2006 State of the Market Report

VOLUME I: INTRODUCTION

MARKET MONITORING UNIT
MARCH 8, 2007

PREFACE

The Market Monitoring Unit of 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 *2006 State of the Market Report* is the ninth such annual report. This report is submitted to the Board of PJM Interconnection pursuant to the PJM Open Access Transmission Tariff (OATT), Attachment M (PJM Market Monitoring Plan):

> The Market Monitoring Unit shall prepare and submit to the PJM Board and to the PJM Members Committee, annual state-of-the-market reports on the state of competition within, and the efficiency of, the PJM Market. In such reports, the Market Monitoring Unit may make recommendations regarding any matter within its purview. The reports to the PJM Board shall include recommendations as to whether changes to the Market Monitoring Unit or the Plan are required.[1]

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.[2]

1 PJM, OATT, "Attachment M: PJM Market Monitoring Plan," Third Revised Sheet No. 452 (Effective July 17, 2006).

2 96 FERC ¶ 61,061 (2001).

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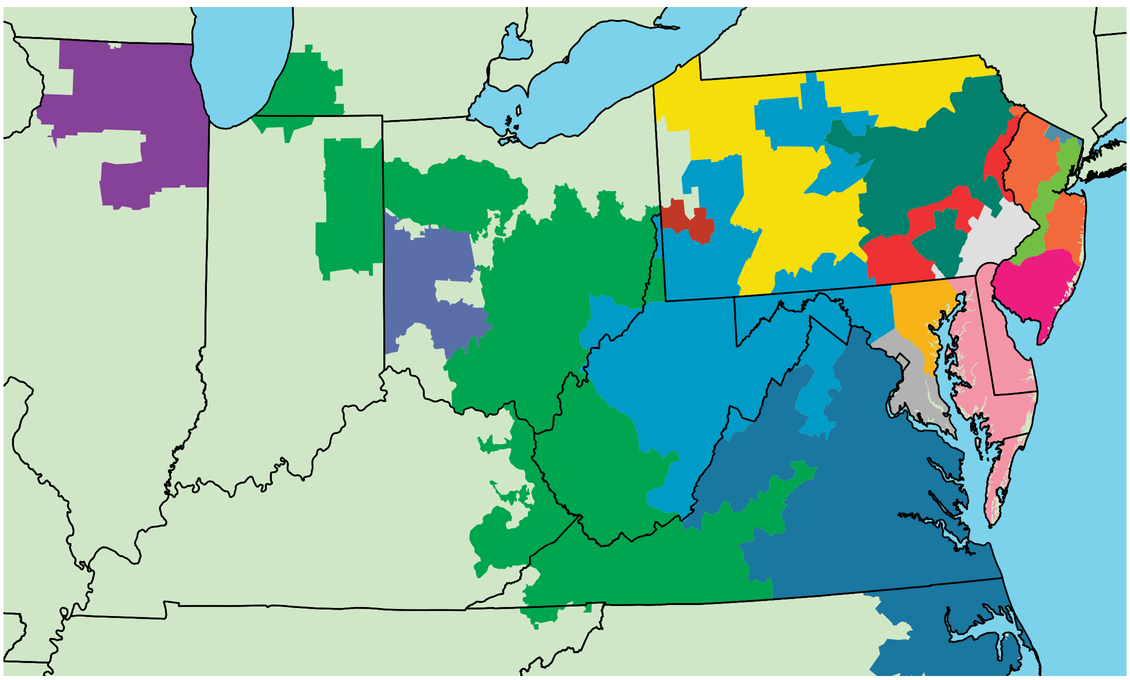
INTRODUCTION

The PJM Interconnection, L.L.C. operates a centrally dispatched, competitive wholesale electric power market that in 2006 had average installed generating capacity of 162,571 megawatts (MW) and more than 450 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. (See Figure 1-1.)[1] As part of that function, PJM coordinates and directs the operation of the transmission grid and plans transmission expansion improvements to maintain grid reliability in this region.

Figure 1-1 PJM's footprint and its zones



Legend

- Allegheny Power Company (AP)
- American Electric Power Co., Inc. (AEP)
- Atlantic Electric Company (AECO)
- Baltimore Gas and Electric Company (BGE)
- The Commonwealth Edison Company (ComEd)
- Dayton Power and Light Company (DAY)
- Delmarva Power and Light (DPL)
- Dominion
- Duquesne Light (DLCO)
- Jersey Central Power and Light Company (JCPL)
- Metropolitan Edison Company (Met-Ed)
- PECO Energy (PECO)
- PPL Electric Utilities (PPL)
- Pennsylvania Electric Company (PENELEC)
- Potomac Electric Power Company (PEPCO)
- Public Service Electric and Gas Company (PSEG)
- Rockland Electric Company (RECO)

1 See *2006 State of the Market Report*, Volume II, Appendix A, "PJM Geography" for maps showing the PJM footprint and its evolution.

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 Synchronized Reserve Markets and the Annual and monthly Balance of Planning Period 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 the Daily Capacity Market on January 1, 1999, and the 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 the 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]

Analysis of 2006 market results requires comparison to prior years. During calendar years 2004 and 2005, PJM integrated five new control zones. When making comparisons to 2004 and 2005, the *2006 State of the Market Report* refers to three phases in calendar year 2004 and two phases in 2005 that correspond to those integrations.[3]

Volume I of the *2006 State of the Market Repor*t is the Introduction. More detailed analysis and results are included in Volume II.

2 See also *2006 State of the Market Report*, Volume II, Appendix B, "PJM Market Milestones."

3 Definitions of these phases are included in the *2006 State of the Market Report*, Volume II, Appendix A, "PJM Geography."

Conclusions

This report assesses the competitiveness of the markets managed by PJM during 2006, including market structure, participant behavior and market performance. This report was prepared by and represents the analysis of PJM's independent Market Monitoring Unit (MMU).

The MMU concludes that in 2006:

- The Energy Market results were competitive;
- The Capacity Market results were competitive;
- The Regulation Market results cannot be determined to have been competitive or to have been noncompetitive;
- The Synchronized Reserve Markets' results were competitive; and
- The FTR Auction Market results were competitive.

Recommendations

The MMU recommends retention of key market rules, specific enhancements to those rules and implementation of new rules that are required for continued competitive results in PJM markets and for continued improvements in the functioning of PJM markets. The recommendations are for continued action where PJM has already identified areas for improvement and for new action in areas where PJM has not yet identified a plan.

Continued Action

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

PJM introduced a new test for local market power in 2006, the three pivotal supplier test. The three pivotal supplier test, as implemented, is consistent with the United States Federal Energy Regulatory Commission's (FERC's) market power tests, encompassed under the delivered price test. This is a flexible, targeted real-time measure of market structure which replaced the offer capping of all units required to relieve a constraint. The application of the three pivotal supplier test successfully limited offer capping in the Energy Market to situations where the local market structure was noncompetitive and where specific owners had structural market power.

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

  The PJM market design includes a variety of rules that effectively limit the incentive to exercise market power and ensure competitive outcomes. These should be retained and every PJM market rule change should be evaluated for its impact on competitive outcomes.

- Implementation of the rules included in PJM's Reliability Pricing Model (RPM) Tariff 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.

  Market power remains a serious concern in the PJM Capacity Market based on market structure conditions in this market including high levels of supplier concentration, frequent occurrences of pivotal suppliers, extreme inelasticity of demand and lack of market power mitigation measures under the market design in place during 2006. The RPM capacity market design explicitly provides that competitive prices can reflect local scarcity while not relying on the exercise of market power to achieve the design objective and explicitly limiting the exercise of market power via the application of the three pivotal supplier test.

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

  PJM and the MMU have been working with the Reserve Market Working Group to develop a set of market design modifications to implement these goals. The process should be completed and the modifications implemented.

- Continued enhancements to 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.

  PJM has significantly improved its approach to the cost-benefit analysis of transmission investments. PJM should continue to evaluate critically its approach, particularly as it applies to constraints with large and persistent market impacts. Developing an approach to weighting and evaluating the multiple metrics in the context of actual transmission projects will require substantial effort. New transmission projects and the lack of existing transmission can have significant impacts on the PJM markets and the goal of transmission planning should ultimately be the incorporation of transmission investment decisions into market-driven processes as much as is practicable.

- Continued enhancement of PJM's posting of market data to promote market transparency.

  PJM has expanded the types and extent of data posted to the Web for public access. PJM should continue to expand data posting consistent with the goal of improving transparency and stimulating competition.

- Provision of data for external control areas to PJM to enable improved analysis of loop flows in order to enhance the efficiency of PJM markets.

  PJM has only limited access to the data required for a complete analysis of loop flow in the Eastern Interconnection. Provision of such data access and completion of the loop flow analysis could significantly enhance the transparency and efficiency of energy markets in both market and non market areas and the efficiency of transactions between market and non market areas. Loop flows have negative impacts on the efficiency of market prices in markets with explicit locational pricing and can be evidence of attempts to game such markets. Loop flows also have poorly understood impacts on non market areas.

- 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.

  PJM and the MMU should continue to ensure that market power is not exercised on the demand side of the market. PJM has improved the design of the demand-side resource rules. The principal barriers to the further development of demand-side response are in the interface between wholesale and retail markets. PJM and the MMU should continue their efforts in that area.

- Based on the experience of the MMU during its eighth 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 FERC. The MMU recommends that the Market Monitoring Plan be further modified consistent with these objectives.[4]

New Action

- Enhancements to PJM's scarcity pricing rules to create stages of scarcity and corresponding stages of locational scarcity pricing in order to ensure competitive prices when scarcity conditions exist in market regions.

  The MMU reviewed the summer of 2006 for scarcity conditions and the market prices that resulted. Based on the results, the MMU suggests that PJM's scarcity pricing mechanism be reviewed and modified. The definition of scarcity should include several steps or states of scarcity, each with an associated price, rather than the single step now in the Tariff. Scarcity pricing should include stages, based on system conditions, with progressive impacts on prices. In addition, the actual market signal needs further refinement. Under the current rules, a scarcity pricing event sets prices for all generators in the defined area at the same level, equal to the highest accepted offer within a scarcity pricing region. The single scarcity price signal should be replaced by locational signals.

- Implementation of targeted, flexible real-time market power mitigation in the Regulation Market.

  PJM consolidated its Regulation Markets into a single Combined Regulation Market, on a trial basis, effective August 1, 2005. The MMU concludes from the analysis of the 2006 data that the PJM Regulation Market in 2006 was characterized by structural market power in 26 percent of the hours, based on the results of the three pivotal supplier test.[5] The MMU also concludes that PJM's consolidation of its Regulation Markets resulted in improved performance and in increased competition compared to the PJM Mid-Atlantic Regulation

4 PJM, OATT, "Attachment M: PJM Market Monitoring Plan," Third Revised Sheet No. 452 (Effective July 17, 2006). Section VII.A. states: "The reports to the PJM Board shall include recommendations as to whether changes to the Market Monitoring Unit or the Plan are required."

5 This is the same conclusion reached in the MMU report on the first year of the Combined Regulation Market. See Market Monitoring Unit, "Analysis of the Combined Regulation Market: August 1, 2005 through July 31, 2006" (October 18, 2006) <http://www.pjm.com/markets/market-monitor/downloads/mmu-reports/20061018-mmu-regulation-market-report.pdf> (76.1 KB).

Market or the Western Region Regulation Market on a stand-alone basis.[6] The MMU concludes that it would be preferable to retain the existing, experimental single PJM Regulation Market as the long-term market if appropriate mitigation can be implemented. Such mitigation, in the form of the three pivotal supplier test, addresses only the hours in which structural market power exists and therefore provides an incentive for the continued development of competition. While suppliers have not provided data on their cost to regulate, an analysis of the Regulation Market based on the MMU's cost estimates indicates that offers above the competitive level set the clearing prices in about 30 percent of the hours. The combined market results include the effects of the current mitigation mechanism which offer caps the two dominant suppliers in every hour. The MMU also recommends that all suppliers be required to provide cost-based regulation offers, consistent with the practice in the energy market.

- Consistent application of local market power rules to all constraints.

  The MMU recommends that the Commission terminate the exemption from offer capping currently applicable to generation resources used to relieve the western, central and eastern reactive limits in the Mid-Atlantic Area Council (MAAC) control zones and the AP South Interface. The MMU recommends that all constraints, including these interfaces, be subject to three pivotal supplier testing as specified in the PJM Amended and Restated Operating Agreement (OA). The exemptions for the identified interfaces are no longer necessary given PJM's dynamic implementation of the three pivotal supplier test based on actual market conditions in real time. It is not necessary to make an *ex ante* decision about the market structure associated with individual interface constraints that applies for an extended period. Prior to the implementation of the three pivotal supplier test, all units required to resolve a constraint were offer capped. For the identified exempt interfaces, this could have resulted in the offer capping of a large number of units even when the relevant market was structurally competitive. That is no longer the case. Under the current PJM dynamic approach, offer capping will be applied only as necessary and will be applied on a non-discriminatory basis for all units operating for all constraints.

- Consideration by the FERC of ending the exemption from offer capping currently applicable to certain units, if those units exercise local market power.

  PJM's offer-capping rules provide that specific units are exempt from offer capping, based on their date of construction. In a January 25, 2005, order, the FERC 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."[7] The FERC 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."[8] A small number of exempt units accounted for a disproportionate share of markup in 2006. Eight exempt units accounted for 33 percent of the overall markup component of PJM prices in 2006.

6 *2005 State of the Market Report* (March 8, 2006), pp. 260-263.

7 110 FERC ¶ 61,053 (2005).

8 110 FERC ¶ 61,053 (2005).

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 Market, bilateral and forward markets and self-supply. Energy transactions analyzed in this report include those in the PJM Day-Ahead and Real-Time Energy Market. These markets provide key benchmarks against which market participants may measure results of transactions in other markets.

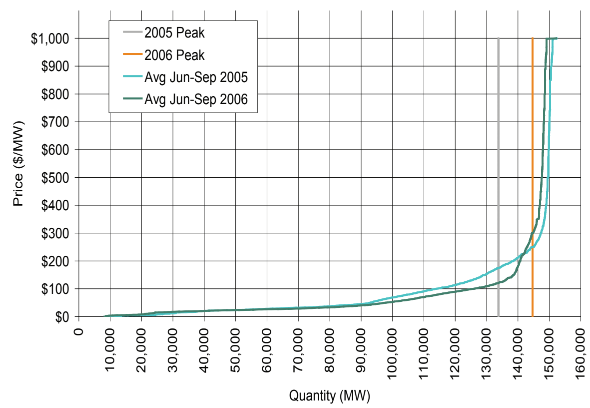
The MMU analyzed measures of market structure, participant conduct and market performance for 2006, including market size, concentration, residual supply index, price-cost markup, net revenue and prices. The MMU concludes that the PJM Energy Market results were competitive in 2006.

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 PJM markets. One of the MMU's primary goals is to identify actual or potential market design flaws.[9] 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 the 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.

Market Structure

- **Supply.** During the June to September 2006 summer period, the PJM Energy Market received an hourly average of 155,600 MW in net supply, including hydroelectric generation, excluding real-time imports or exports. The summer 2006 net supply was 1,160 MW higher than the summer 2005 net supply. (See Figure 1-2.) The increase was comprised of 400 MW of increased hydroelectric power generation and a 760 MW increase in net capacity in the regional transmission organization (RTO) footprint.

Figure 1-2 Average PJM aggregate supply curves: Summers 2005 and 2006



- **Demand.** The PJM system peak load in 2006 was 144,644 MW in the hour ended 1700 EPT on August 2, 2006, while the PJM peak load in 2005 was 133,763 in the hour ended 1600 on July 26, 2005.[10] The 2006 peak load was 10,881 MW, or 8.1 percent, higher than the 2005 peak load and therefore intersected the supply curve at a higher price level than would have occurred with a lower level of demand.

9 See PJM Open Access Transmission Tariff (OATT), "Attachment M: Market Monitoring Plan," Third Revised Sheet No. 452 (Effective July 17, 2006).

10 For the purpose of Volume I and Volume II of the *2006 State of the Market Report*, all hours are presented and all hourly data are analyzed using Eastern Prevailing Time (EPT). See Appendix K, "Glossary," for a definition of EPT and its relationship to Eastern Standard Time (EST) and Eastern Daylight Time (EDT).

- **Market 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.

- **Local Market Structure and Offer Capping.** Noncompetitive local market structure is the trigger for offer capping. PJM implemented a flexible, targeted, real-time approach to offer capping (the three pivotal supplier test) as the trigger for offer capping in 2006. PJM offer caps units only when their owners would otherwise exercise local market power. Offer capping is an effective means of addressing local market power. Offer-capping levels have historically been low in PJM and generally declined in 2006. (See Table 1-1.)

Table 1-1 Annual offer-capping statistics: Calendar years 2002 to 2006

	Real Time		Day Ahead	
	Unit Hours Capped	MW Capped	Unit Hours Capped	MW Capped
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%
2006	1.0%	0.2%	0.4%	0.1%

- **Local Market Structure.** A summary of the results of PJM's application of the three pivotal supplier test is presented for all constraints which occurred for 100 or more hours during calendar year 2006. The analysis of the application of the three pivotal supplier test to local markets demonstrates that it is working successfully to exempt owners when the market structure is competitive and to offer cap only pivotal owners when the market structure is noncompetitive.

  Specific geographic areas of PJM exhibited moderate to high levels of concentration when transmission constraints defined local markets. While PJM's local market power mitigation rules prevented the exercise of market power in these circumstances, the rules do not apply to units exempt from offer capping and therefore did not prevent the exercise of market power by a small number of such units.

- **Characteristics of Marginal Units.** The concentration of ownership of all marginal units in the Energy Market provides additional information about market structure. The higher the level of concentration of ownership of marginal units the greater is the potential market power issue. In 2006, the top four companies accounted for 49 percent of the load-weighted, system average locational marginal price (LMP).

  In 2006, coal-fired units accounted for 70 percent of marginal units and natural gas-fired units accounted for 25 percent of all marginal units.

Market Conduct

- **Price-Cost Markup.** The price-cost markup index is a measure of conduct or behavior by the owners of generating units. For marginal units, the markup index is a measure of market power. A positive markup by marginal units will result in a difference between the observed market price and the competitive market price. The annual average markup index was 0.00 with a monthly average maximum of 0.05 in February and a monthly average minimum of -0.02 in August. The markup at times substantially exceeded these levels and was at times below these levels but the overall results support the conclusion that prices in PJM are set, on average, by marginal units operating at or very close to their marginal costs. This is strong evidence of competitive behavior.

Market Performance: Markup, Load and Locational Marginal Price

- **Markup.** The markup conduct of individual owners and units has an impact on market prices that is not explicitly captured in the conduct markup measure. The MMU has added explicit measures of the price component of marginal unit markups. The markup component of the overall system load-weighted, average LMP was $1.54 per MWh, or 2.9 percent. The markup was $3.08 per MWh during peak hours and -$0.10 per MWh during off-peak hours. The markup component of price at times substantially exceeded these levels and was at times below these levels, but the overall results support the conclusion that prices in PJM are set, on average, by marginal units operating at or very close to their marginal costs. This is strong evidence of competitive behavior and competitive market performance.

  A substantial portion of the markup, $0.60 per MWh or 39 percent occurred on high-load days during the summer of 2006. Markup on high-load days is likely to be the result of appropriate scarcity pricing rather than market power.

  The units that are exempt from offer capping for local market power accounted for $0.56 per MWh, or 36 percent, of the markup for all days. This is a disproportionate share, given that only 43 of 56 exempt units were marginal and that only eight exempt units of the 43 accounted for $0.50, or 90 percent, of this markup component of price. The average markup per exempt unit is about nine times higher than for non-exempt units, and the average markup for the top eight exempt units is about 43 times higher than for non-exempt units.

- **Load.** On average, PJM real-time load increased in 2006 by 1.7 percent over 2005, but this increase reflected the fact that the first four months of 2006 included Dominion load which was not present in the four months of 2005. The 2006 PJM real-time average load, calculated to be directly comparable to 2005 by excluding the 2006 load resulting from the integration of Dominion for the first four months, was lower than in 2005 by about 2.5 percent.

- **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 real-time energy market prices decreased in 2006. The simple average system LMP was 15.2 percent lower in 2006 than in 2005, $49.27 per MWh versus $58.08 per MWh. The load-weighted LMP was 15.9 percent lower in 2006 than in 2005, $53.35 per MWh versus $63.46 per MWh. The fuel-cost-adjusted, load-weighted, average LMP was 5.6 percent lower in 2006 than in 2005, $59.89 per MWh compared to $63.46 per MWh.

Demand-Side Response

- **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 on August 2, 2006 (the peak day in 2006), were 3,511 MW of which 1,679 MW were from active load management, 1,081 MW from the Emergency Load-Response Program and 1,101 MW from the Economic Load-Response Program. There were 350 MW enrolled in both the Load-Response Program and in active load management. When additional demand-side resources as of June 1, 2006, reported by PJM customers in response to a survey, are included, there were 6,703 MW in total DSR resources in the summer of 2006, 4.6 percent of PJM's peak demand. Including the PJM Economic Program and survey responses, there were 2,597 MW of load directly exposed to LMP in 2006, or 1.8 percent of peak load.

Conclusion

The MMU analyzed key elements of PJM energy market structure, participant conduct and market performance for calendar year 2006, including aggregate supply and demand, concentration ratios, local market concentration ratios, price-cost markup, offer capping, participation in demand-side response programs, loads and prices in this section of the report. The next section continues the analysis of the PJM Energy Market including additional measures of market performance.

Aggregate supply increased by about 1,160 MW when comparing the summer of 2006 to the summer of 2005 while aggregate peak load increased by 10,881 MW, modifying the general supply-demand balance from 2005 with a corresponding impact on peak energy market prices. Overall load was lower than in 2005, when measured on a comparable footprint basis, with a corresponding moderating impact on overall average prices. Market concentration levels remained moderate and average markups remained low. A small number of units exempt from offer capping accounted for a disproportionate share of the system markup. 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.

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 between price and marginal cost. 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.

PJM introduced a new test for structural market power in 2006, the three pivotal supplier test. This is a flexible, targeted real-time measure of market structure which replaced the offer capping of all units required to relieve a constraint. A generation owner or group of generation owners is pivotal for a local market if the output of the owners' generation facilities is required in order to relieve a transmission constraint. When a generation owner or group of owners is pivotal, it has the ability to increase the market price above the competitive level. The three pivotal supplier test, as implemented, is consistent with the FERC's market power tests, encompassed under the delivered price test. The three pivotal supplier test is an application of the delivered price test to both the Real-Time Market and hourly Day-Ahead Market. The three pivotal supplier test explicitly incorporates the impact of excess supply and implicitly accounts for the impact of the price elasticity of demand in the market power tests.

The three pivotal supplier test is applied by PJM on an ongoing basis for local energy markets in order to determine whether offer capping is required for constraints not exempt from offer capping. The result of the introduction of the three pivotal supplier test was to limit offer capping to situations when the local market structure was noncompetitive and where specific owners had structural market power. The analysis of the application of the three pivotal supplier test demonstrates that it is working successfully to exempt owners when the local market structure is competitive and to offer cap owners when the local market structure is noncompetitive.

The MMU recommends that the FERC terminate the exemption from offer capping currently applicable to generation resources used to relieve the western, central and eastern reactive limits in the Mid-Atlantic Area Council (MAAC) control zones and the AP South Interface.[11] The MMU recommends that all constraints, including these interfaces, be subject to three pivotal supplier testing as specified in the PJM Amended and Restated Operating Agreement (OA). The exemptions for the identified interfaces are no longer necessary given PJM's dynamic implementation of the three pivotal supplier test based on actual market conditions in real time. It is not necessary to make an *ex ante* decision about the market structure associated with individual interface constraints that applies for an extended period. Prior to the implementation of the three pivotal supplier test, all units required to resolve a constraint were offer capped whenever the constraint was binding. For the identified exempt interfaces, this could have resulted in the inappropriate offer capping of a large number of units even when the relevant market was structurally competitive. That is no longer the case. Under the current PJM dynamic approach, offer capping is applied only as necessary and is applied on a non-discriminatory basis for all units operating for all constraints.

The MMU recommends that the FERC terminate the exemption from offer capping currently applicable to certain units, if those units exercise local market power. PJM's offer-capping rules provide that specific units are exempt from offer capping, based on their date of construction. In a January 25, 2005, order, the FERC 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."[12] The FERC 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."[13] A small number of exempt units accounted for a disproportionate share of markup in 2006. Eight exempt units accounted for 33 percent of the overall markup component of prices in 2006.

The MMU has disaggregated the average, load-weighted system price into its component parts as seen in Table 1-2. Fuel costs accounted for 76.0 percent, emission costs for 13.0 percent and markup for 2.9 percent of the system average LMP in 2006. Of the $1.54 LMP component of markup, exempt units accounted for 36 percent, of which 90 percent was contributed by eight units.

11 See PJM OA, Sections 6.4.1(d)(ii) and 6.4.1(e) (January 19, 2007).

12 110 FERC ¶ 61,053 (2005).

13 110 FERC ¶ 61,053 (2005).

Table 1-2 Components of annual PJM load-weighted, average LMP: Calendar year 2006

Element	Contribution to LMP	Percent
Coal	$20.67	38.7%
Gas	$17.23	32.3%
Oil	$2.65	5.0%
Uranium	$0.00	0.0%
Wind	$0.01	0.0%
NO_x	$1.53	2.9%
SO_2	$5.39	10.1%
VOM	$2.67	5.0%
Markup	$1.54	2.9%
Constrained Off	$1.06	2.0%
NA	$0.59	1.1%

Energy Market results, including prices, for 2006 generally reflected supply-demand fundamentals. Lower nominal and load-weighted prices are consistent with a competitive outcome as the lower prices reflect both lower input fuel costs and lower overall demand. If fuel costs for the year 2006 had been the same as for 2005, the 2006 load-weighted LMP would have been higher than it was, $59.89 per MWh instead of $53.35 per MWh. Fuel-cost reductions were a substantial part (64.7 percent) of the reason for lower LMP in 2006, but prices would have been lower in the absence of the lower fuel costs. The overall market results support the conclusion that prices in PJM are set, on average, by marginal units operating at or very close to their marginal costs. This is strong evidence of competitive behavior and competitive market outcomes. Given the structure of the Energy Market, tighter markets or a change in participant behavior are potential sources of concern in the Energy Market. The MMU concludes that the PJM Energy Market results were competitive in 2006.

Energy Market, Part 2

The MMU analyzed measures of PJM Energy Market structure, participant conduct and market performance for 2006. As part of the review of market performance, the 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.

Generator 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 all PJM markets. 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 2006 net revenue, including both the Day-Ahead and Real-Time Energy Market, indicates that the fixed costs of new peaking, midmerit and coal-fired baseload were not fully covered. During the eight-year period 1999 to 2006, the data lead to the conclusion that net revenues were less than the fixed costs of generation and that this shortfall resulted both from lower, less volatile energy market prices and lower capacity credit market prices in the last several years.

  Under an economic dispatch scenario, the eight-year net revenue averaged $30,212 per installed MW-year for a new entrant combustion turbine

(CT) plant, $56,120 per installed MW-year for a new entrant combined-cycle (CC) plant and $150,939 per installed MW-year for a new entrant pulverized coal (CP) plant. (See Table 1-3.) Thus, under perfect economic dispatch over the eight-year period, the average, net revenue was not adequate to cover the first year's fixed costs for the CT, CC or CP plant.

- **Zonal Net Revenues.** Zonal revenues reflect differentials in LMP across the system and illustrate the substantial impact that locational prices have on economic incentives. For a CT, while the PJM average net revenue in 2006 was $10,996 per MW-day, the maximum zonal CT net revenue was $37,801 in the PEPCO control zone and the minimum was $4,342 in the DAY control zone. For a CC, while the PJM average net revenue in 2006 was $44,692 per MW-day, the maximum zonal CC net revenue was $91,120 in the PEPCO control zone and the minimum was $18,897 in the DLCO control zone. For a CP, while the PJM average net revenue in 2006 was $177,852 per MW-day, the maximum zonal CP net revenue was $254,964 in the PEPCO control zone and the minimum was $102,923 in the DLCO control zone.

  While the maximum zonal CT net revenue was well below the annual fixed costs of a new CT, the maximum CC zonal net revenue was close to the annual fixed costs of a new CC and the maximum CP zonal net revenue was substantially in excess of the annual fixed costs of a new CP. Thus, the higher LMPs in the eastern PJM zones, reflecting transmission limitations and congestion, have a positive impact on the incentive to invest in those areas.

Table 1-3 Total net revenue and 20-year, levelized fixed cost for new entry CT, CC and CP generators: Economic dispatch assumed

	CT		CC		CP	
	Economic Dispatch Net Revenue	20-Year Levelized Fixed Cost	Economic Dispatch Net Revenue	20-Year Levelized Fixed Cost	Economic Dispatch Net Revenue	20-Year Levelized Fixed Cost
1999	$74,537	$72,207	$100,700	$93,549	$118,021	$208,247
2000	$30,946	$72,207	$47,592	$93,549	$134,563	$208,247
2001	$63,462	$72,207	$86,670	$93,549	$129,271	$208,247
2002	$28,260	$72,207	$52,272	$93,549	$112,131	$208,247
2003	$10,565	$72,207	$35,591	$93,549	$169,510	$208,247
2004	$8,543	$72,207	$35,785	$93,549	$133,125	$208,247
2005	$10,437	$72,207	$40,817	$93,549	$228,430	$208,247
2006	$14,948	$80,315	$49,529	$99,230	$182,461	$267,792
Avg	$30,212	$73,221	$56,120	$94,259	$150,939	$215,690

Existing and Planned Generation

- **PJM Installed Capacity.** During the period January 1, through December 31, 2006, PJM installed capacity remained relatively flat with the exception of modest changes in imports and exports. Retirements were offset by new additions and the installed capacity on December 31, 2006, was only 884 MW less than on January 1, 2006.

- **PJM Installed Capacity by Fuel Type.** At the end of 2006, PJM installed capacity was 162,143 MW. Of the total installed capacity, 41.0 percent was coal, 29.0 percent was natural gas, 18.5 percent was nuclear, 6.6 percent was oil, 4.4 percent was hydroelectric and 0.4 percent was solid waste.

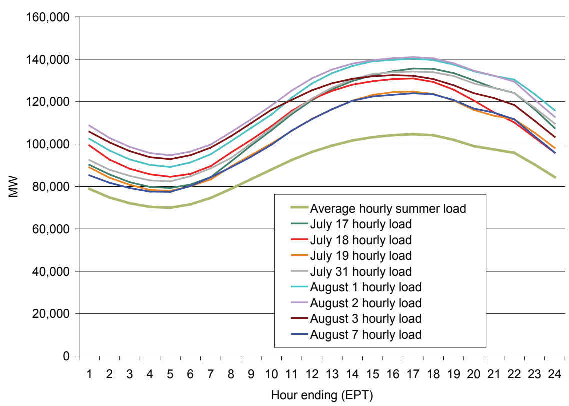
- **Generation Fuel Mix.** During 2006, coal was 56.8 percent, nuclear 34.6 percent, natural gas 5.5 percent, oil 0.3 percent, hydroelectric 2.0 percent, solid waste 0.7 percent and wind 0.1 percent of total generation.

- **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 has potentially significant implications for future congestion, the role of firm and interruptible gas supply and natural gas supply infrastructure.

Scarcity

- **Scarcity.** During the summer of 2006, there were 70 hours of high load that occurred from July 17 through July 19, from July 31 through August 3 and on August 7. Within these 70 hours, there were 10 hours on August 1 and August 2 that met the criteria for potential within-hour scarcity. (See Figure 1-3.)

Figure 1-3 High-load day hourly load and average hourly load: Summer 2006



- **Scarcity Pricing Events in 2006.** PJM implemented administratively based, scarcity pricing rules in 2006.[14] In 2005 it was recognized that changing market dynamics created by PJM's expanded footprint, along with PJM's continued need for administratively employed emergency mechanisms to maintain system reliability under conditions of scarcity, had created a need for an administratively based scarcity pricing mechanism. Based on the definition of scarcity outlined in the Tariff, there were no official scarcity pricing events in 2006, despite record coincident-peak loads recorded across the PJM footprint and within specific zones.

- **Modifications to Scarcity Pricing.** While PJM's use of specific emergency procedures is a reasonable indicator of scarcity conditions, an analysis of 2006 market results suggests that PJM's current set of scarcity pricing rules may need refinement. The MMU reviewed the summer of 2006 for scarcity conditions and the market prices that resulted. Based on the results, the MMU suggests that PJM's scarcity pricing mechanism be reviewed and modified. The definition of scarcity should include several steps or states of scarcity, each with an associated

14 114 FERC ¶61,076 (2006).

price, rather than the single step now in the Tariff. Scarcity pricing should include stages, based on system conditions, with progressive impacts on prices. In addition, the actual market signal needs further refinement. Under the current rules, a scarcity pricing event sets prices for all generators in the defined area at the same level, equal to the highest accepted offer within a scarcity pricing region. The single scarcity price signal should be replaced by locational signals.

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, operating reserve 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 2006.** Operating reserve charges were lower in 2006 by 53 percent. (See Table 1-4.) The reasons for the substantial decrease in the balancing operating reserve charges included decreased fuel costs and improved operating practices by PJM.

Table 1-4 Total day-ahead and balancing operating reserve charges: Calendar years 1999 to 2006[15]

	Total Operating Reserve Credits	Annual Credit Change	Operating Reserve as Percent of Total Billing	Day-Ahead $/MWh	Day-Ahead Change	Balancing $/MWh	Balancing Change
1999	$133,897,428	NA	7.5%	NA	NA	NA	NA
2000	$216,985,147	62.1%	9.6%	$0.341	NA	$0.535	NA
2001	$290,867,269	34.0%	8.7%	$0.275	(19.5%)	$1.070	100.2%
2002	$237,102,574	(18.5%)	5.0%	$0.164	(40.4%)	$0.787	(26.4%)
2003	$289,510,257	22.1%	4.2%	$0.226	38.2%	$1.197	52.0%
2004	$414,891,790	43.3%	4.8%	$0.230	1.7%	$1.236	3.3%
2005	$682,781,889	64.6%	3.0%	$0.076	(66.9%)	$2.758	123.1%
2006	$322,315,152	(52.8%)	1.5%	$0.078	2.6%	$1.331	(51.7%)

15 Calculated values shown in Table 1-4 are based on unrounded underlying data and may differ from calculations based on the rounded values shown in the table.

Conclusion

Wholesale electric power markets are affected by externally imposed reliability requirements. A regulatory authority external to the market makes a determination as to the acceptable level of reliability which is enforced through a requirement to maintain a target level of installed or unforced capacity. 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 reliability requirement results in maintaining a level of capacity in excess of the level that would result from the operation of an energy market alone. The result of that additional capacity 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 electric power market design. Scarcity pricing must be designed to ensure that market prices reflect actual market conditions, that scarcity pricing occurs in well-defined stages with transparent triggers and prices and that there are strong incentives for competitive behavior and strong disincentives to exercise market power. Such administrative scarcity pricing is a key link between energy and capacity markets. With a capacity market design that appropriately reflects scarcity rents in the energy market, scarcity pricing can be a mechanism to appropriately increase reliance on the energy market as a source of revenues and incentives in a competitive market without reliance on the exercise of market power.

While net revenue in PJM has been almost 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 and close to covering those costs in 2006 in some eastern zones, net revenue has generally 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, although the contribution of the Energy Market will be more consistent with reliability signals if the Energy Market appropriately provides for scarcity pricing when scarcity does occur.

A capacity market is a formal mechanism, with both administrative and market-based components, 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 an explicit mechanism for valuing capacity and is preferable to non market and non-transparent mechanisms for that reason.

PJM's 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 Market.

The ultimate test of a competitive market design is whether it provides incentives to invest that are acted upon by market participants, based on incentives endogenous to the competitive market design and not in reliance on the potential or actual exercise of market power. The net revenue performance of the Balancing Energy Market over the last eight years and the Day-Ahead Energy Market over the last seven years illustrates that additional market modifications are necessary if PJM is to pass that test. A combination of the RPM design and enhancements of scarcity pricing are two such modifications.

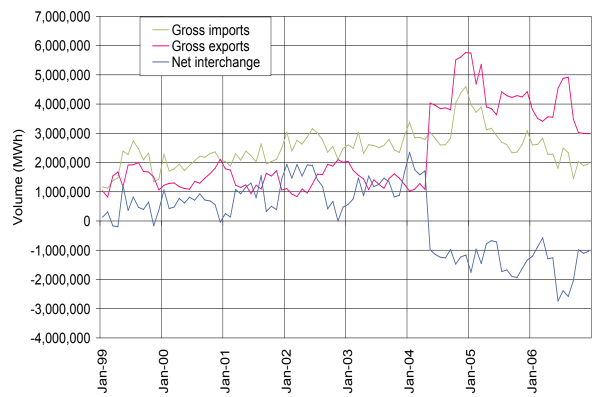
Interchange Transactions

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.

Interchange Transaction Activity

- **Aggregate Imports and Exports.** During 2006, PJM was a net exporter of energy, with monthly net interchange averaging -1.5 million MWh.[16] Gross monthly import volumes averaged 2.2 million MWh while gross monthly exports averaged 3.7 million MWh. (See Figure 1-4.)

Figure 1-4 PJM import and export transaction volume history: Calendar years 1999 to 2006



- **Transactions in the Day-Ahead Energy Market.** While PJM market participants historically imported and exported energy primarily in the Real-Time Energy Market, the share of activity in the Day-Ahead Energy Market has increased substantially. In 2006, gross imports in the Day-Ahead Energy Market were 77 percent of the Real-Time Market's gross imports (50 percent in 2005) while gross exports in the Day-Ahead Market were 86 percent of the Real-Time Market's gross exports (50 percent in 2005) and net interchange in the Day-Ahead Energy Market was almost identical to net interchange in the Real-Time Energy Market.

16 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.

- **Interface Imports and Exports.**[17] There were net exports at 15 of PJM's 21 interfaces in 2006. Three interfaces accounted for 65 percent of the total net exports, PJM/Tennessee Valley Authority (TVA) with 33 percent, PJM/MidAmerican Energy Company (MEC) with 17 percent and PJM/New York Independent System Operator (NYIS) with 15 percent of the net export volume. There were net imports at five of PJM's interfaces. Three interfaces accounted for 97 percent of the net import volume, PJM/Ohio Valley Electric Corporation (OVEC) with 76 percent, PJM/Illinois Power Company (IP) with 12 percent and PJM/Duke Energy Corp. (DUK) with 9 percent of the net import volume.

Interchange Transaction Topics

- **Operating Agreements with Bordering Areas.**
  - **PJM/Midwest ISO Joint Operating Agreement (JOA).** The "Joint Operating Agreement between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C." continued in its second, and final, phase of implementation including market-to-market activity and coordinated market-based congestion management within and between both markets.[18]
  - **PJM, Midwest ISO and TVA Joint Reliability Coordination Agreement.**[19] The Joint Reliability Coordination Agreement (JRCA) executed on April 22, 2005, provides for comprehensive reliability management and congestion relief among the wholesale electricity markets of the Midwest ISO and PJM and the service territory of TVA. The agreement continued to be in effect through 2006.
  - **PJM and Progress Energy Carolinas, Inc. Joint Operating Agreement.**[20] On September 9, 2005, the FERC approved a JOA between PJM and Progress Energy Carolinas, Inc. (PEC), with an effective date of July 30, 2005. The agreement remained in effect through 2006.
- **PJM TLRs.** The number of transmission loading relief procedures (TLRs) issued by PJM declined from 2005. The reduction in TLRs declared by both PJM and the Midwest ISO is evidence that market signals are being used to manage inter area transactions rather than market interventions.
- **PJM Interface Pricing with Organized Markets.**
  - **PJM and Midwest ISO Interface Pricing.** During 2006, the relationship between prices at the PJM/MISO Interface and at the MISO/PJM Interface reflected economic fundamentals as did the relationship between interface price differentials and power flows between PJM and the Midwest ISO.
  - **PJM and New York ISO Interface Pricing.** During 2006, the relationship between prices at the PJM/NYIS Interface and at the New York Independent System Operator (NYISO) PJM proxy bus reflected economic fundamentals as did the relationship between interface price differentials and power flows between PJM and NYISO. As in 2005, both continued to be affected by differences in institutional and operating practices between PJM and NYISO.

17 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.

18 See "Joint Operating Agreement between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C." (December 31, 2003) (Accessed January 8, 2007) <http://www.pjm.com/documents/downloads/agreements/joa-complete.pdf> (1,331 KB).

19 See "Joint Reliability Coordination (JRCA) among the Midwest ISO, PJM and TVA" (April 22, 2005) (Accessed January 17, 2007) <http://www.pjm.com/documents/downloads/agreements/ 20050422-jrca-final.pdf> (145 KB).

20 See "Joint Operating Agreement (JOA) between Progress Energy Carolinas, Inc. and PJM" (July 29, 2005) (Accessed January 17, 2007) <http://www.pjm.com/documents/ferc/ documents/2005/20050729-er05-___-000.pdf> (2.90 MB).

– **Consolidated Edison Company of New York, Inc. (Con Edison) and Public Service Electric and Gas Company (PSE&G) Wheeling Contracts.**[21] PJM continued to operate under the terms of the operating protocol (developed in 2005) during 2006.[22] Con Edison, however, is concerned that there have been apparent departures from protocol requirements. Periodic meetings were held with all participants to discuss the operation and progress towards improved delivery. Formal filings to implement further improvements are expected in 2007.

Interchange Transaction Issues

- **Loop 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. Although PJM's total scheduled and actual flows differed by less than 2 percent in 2006, there were significant differences for individual interfaces. Loop flows are a significant concern because they have negative impacts on the efficiency of market areas with explicit locational pricing, including impacts on locational prices, on FTR revenue adequacy and on system operations, and can be evidence of attempts to game such markets.

- **Loop Flows at the PJM/MECS and PJM/TVA Interfaces.** As in 2005, the PJM/Michigan Electric Coordinated System (MECS) Interface continued to exhibit large imbalances between scheduled and actual power flows, particularly during the overnight off-peak hours. The PJM/TVA Interface also exhibited large mismatches between scheduled and actual power flows. The PJM/MECS differences and the PJM/TVA differences were in opposite directions. The net difference between scheduled flows and actual flows at the PJM/TVA Interface was imports while the net difference at the PJM/MECS Interface was exports.

- **Loop Flows at PJM's Southern Interfaces.** There was a persistent difference between scheduled and actual power flows at PJM's southern interfaces (PJM/TVA and PJM/ Eastern Kentucky Power Corporation (EKPC) to the west and PJM/eastern portion of Carolina Power & Light Company (CPLE), PJM/western portion of Carolina Power & Light Company (CPLW) and PJM/DUK to the east) that grew larger through the summer. In the southwest for example, while actual flows at the PJM/TVA and PJM/EKPC Interfaces were relatively small exports, scheduled energy exports at these interfaces were very large. The scheduled exports increased further in June, July and August.

  In order to reflect the actual flow of transactions associated with the southwest and southeast interface pricing points, on October 1, 2006, PJM began to price imports and exports differently based on their impacts on the PJM transmission system. After the pricing point change, scheduled flows more closely matched actual flows, primarily as a result of reductions in scheduled flows while actual flows remained relatively unchanged. In particular, a significant level of scheduled exports to the southwest stopped after the modification of the pricing points. A small number of market participants had been regularly scheduling large exports and the decline in their scheduling activity was responsible for most of the improved convergence between actual and scheduled flows.

- **Data Required for Full Loop Flow Analysis.** A complete analysis of loop flow across the Eastern Interconnection could enhance overall market efficiency and shed light on the interactions among market and non market areas. This is

21 Prior state of the market reports indicated that this contract is an agreement between Con Edison and PSEG. The contract is between Con Edison and PSE&G, a wholly owned subsidiary of PSEG.

22 111 FERC ¶ 61,228 (2005).

important because loop flows have negative impacts on the efficiency of market prices in markets with explicit locational pricing and can be evidence of attempts to game such markets. Loop flows also have poorly understood impacts on non market areas. More broadly, a complete analysis of loop flow could advance the overall transparency of electricity transactions. The data to fully analyze loop flows affecting PJM are not currently available to PJM.

- **Wisconsin Public Service Corporation Complaint.** On August 15, 2006, the Wisconsin Public Service Corporation (WPS) filed a complaint against PJM and the Midwest ISO at the FERC requesting that the FERC direct PJM and Midwest ISO (the regional transmission organizations (RTOs)) to promptly institute joint unit commitment and dispatch over the entire PJM/MISO footprint. The RTOs responded that an appropriate cost-benefit analysis does not justify joint dispatch at the present time. Nonetheless the RTOs recognize that there are actions that can be taken to address the lack of convergence of shadow prices. The RTOs are developing an approach to improve shadow price convergence.

- **Ramp Reservation Rule Change.** In early 2006 the number of market participant complaints regarding the inability to obtain ramp in a timely manner and complaints about large ramp volume swings became more persistent. The MMU's efforts to publicly identify the issues with such conduct resulted in improved behavior, but similar efforts in the past had only temporary effects. As a result, the MMU developed, PJM proposed, and the membership agreed, to changes in the ramp reservation rules to impose limits on the time that a ramp reservation could be held without an associated energy schedule. The new rules had a significant, positive impact on ramp reservation behavior.

Conclusion

Transactions between PJM and the multiple control areas contiguous to PJM are part of a single energy market. While some of these contiguous control areas are termed market areas and some are termed non market areas, all electricity transactions are part of a single energy market in the Eastern Interconnection. Nonetheless, there are significant differences between market and non market areas. Market areas, like PJM, include essential features such as locational marginal pricing, financial hedging tools (FTRs and ARRs in PJM) and least cost, security-constrained economic dispatch. Non market areas do not include these features. The market areas are extremely transparent and the non market areas are nontransparent.

The MMU analyzed the transactions between PJM and neighboring control areas for 2006 including evolving transactions patterns, economics and issues. PJM continued to be a net exporter of energy and a large share of both import and export activity occurred at a small number of interfaces. Three interfaces accounted for 65 percent of the total net exports and three interfaces accounted for 97 percent of the net import volume. While PJM market participants historically imported and exported energy primarily in the Real-Time Energy Market, the share of activity in the Day-Ahead Energy Market has increased substantially to 77 percent and 86 percent of gross imports and exports, respectively, while net interchange in the Day-Ahead Market is approximately equal to that in the Real-Time Energy Market.

As the data show, there is a substantial level of transactions between PJM and the contiguous control areas. The transactions with other market areas are driven by the market fundamentals within each area and between market areas. However, there is room to improve current market-to-market coordination to ensure that these areas together more closely approach the outcomes and opportunities of a single, transparent market. The transactions with non market areas are driven by a mix of incentives including market fundamentals but are more difficult to manage because of the inherent inconsistency between the contract path approach taken in non market areas and the explicit locational-price-driven approach in market areas. A significant issue is the ability of non market transactions to impose uncompensated costs on market areas in the absence of transparency and appropriate market signals. For interactions with both market and non market areas, the goal is to increase the role of market forces consistent with actual power flows and more closely approach the outcomes and opportunities of a single, transparent market.

In order to manage interactions with other market areas, PJM has entered into formal agreements with a number of control areas. The redispatch agreement between PJM and the Midwest ISO is a model for such agreements and is being continuously improved. As interactions with external areas are increasingly governed by economic fundamentals, interface prices and volumes reflect supply and demand conditions and the number of required interventions in the market has declined, as measured for example by the reduction in TLRs declared by both PJM and the Midwest ISO in 2006.

In order to manage interactions with non market areas, PJM has entered into coordination agreements with other control areas as a first step. In addition, PJM has attempted to address loop flows by creating and modifying interface prices that reflect actual power flows, regardless of contract path. Loop flows are also managed through the use of redispatch and TLR procedures. PJM has entered into dynamic scheduling agreements with generation owners to permit transparent, market-based signals and responses. PJM has modified the rules governing the use of limited transaction ramp capability between PJM and contiguous control areas to help ensure that transactions are free to respond to market signals and to reduce the ability to game or hoard ramp.

Loop flows are measured as the difference between actual and scheduled (contract path) flows at one or more specific interfaces. Loop flows do not exist within markets because power flows are explicitly priced under locational marginal pricing, but markets can create loop flows in external control areas. PJM attempts to manage loop flows by creating interface prices that reflect the actual power flows, regardless of contract path. As one approach to a specific loop flow issue, the southeast and southwest pricing points were consolidated into a single pricing point with separate import and export pricing. But this approach cannot be completely successful as long as it is possible to schedule a transaction and be paid based on that schedule, regardless of how the power flows.

PJM continues to face significant loop flows for reasons that are not yet fully understood, in large part as a result of inadequate access to the required data. A complete analysis of loop flow across the Eastern Interconnection could improve overall market efficiency and enhance the transparency of the interactions among market and non market areas. This is important because loop flows have negative impacts on the efficiency of market prices in markets with explicit locational pricing and can be evidence of attempts to game such markets. Loop flows also have poorly understood impacts on non market areas.

Market participants at times request and receive ramp reservations that are not actually used for an energy transaction. When this happens, other market participants can be prevented from obtaining ramp reservations and PJM operations and markets can be affected by the large, last minute changes in expected external power flow. This behavior can reflect attempts to manipulate PJM prices, attempts to disadvantage competitors, mistakes by participants or unanticipated failures to complete the underlying transaction.

In response, the MMU developed, PJM proposed, and the membership supported, changes in the import and export ramp reservation rules to impose limits on the time that a ramp reservation could be held without an associated energy schedule. These changes became effective on August 7, 2006. The distributed nature of automatic expirations under the new rule has improved the efficiency of ramp usage.

PJM has also successfully used other approaches to enhance the efficiency of interactions with neighboring control areas. The Con Edison/PSE&G wheeling contracts continue to be managed under a FERC-approved protocol that has improved operations and resulted in more explicit pricing for the associated power flows.

Capacity Market

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 (CCM) 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.[23]

The PJM Capacity Credit Market[24] 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,[25] Monthly and Multimonthly CCM. The PJM CCM is intended to provide a transparent, market-based mechanism for 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 CCM permits LSEs to match capacity resources with short-term shifts in retail load while the Interval, Monthly and Multimonthly CCMs provide mechanisms to match longer-term obligations with capacity resources.

23 See *2006 State of the Market Report*, Volume II, Appendix K, "Glossary," for definitions of PJM Capacity Credit Market terms.

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

25 PJM defines three intervals for its Capacity Market. 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.

In June 2007, it is expected that the current capacity market construct will be replaced with the RPM capacity market construct.

From June 2004 through May 2005, a separate ComEd capacity credit market had operated under PJM rules, but with capacity obligations and capabilities measured in installed MW. That changed on June 1, 2005, when all ComEd capacity markets became fully integrated into the PJM capacity marketplace. To analyze PJM Capacity Market performance during 2006 as compared to 2005, the *2006 State of the Market Report* limits the relevant 2005 period to the one that started on June 1, 2005, and ended on December 31, 2005, when all capacity became measured by unforced MW. The report refers to it as the 2005 ComEd post capacity integration (PCI) period (i.e., the 2005 ComEd PCI period).[26]

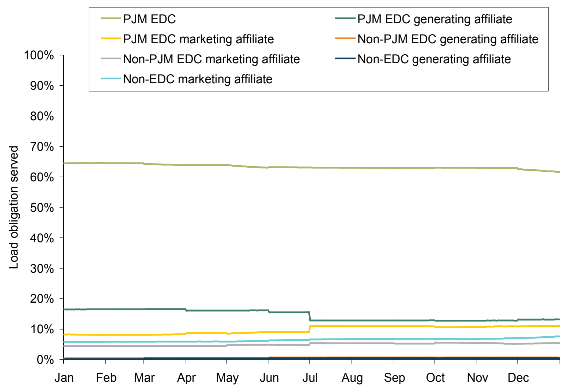
Market Structure

- **Supply.** Unforced capacity remained relatively constant in the PJM CCM in 2006 compared to the 2005 ComEd PCI period. Average unforced capacity decreased by 298 MW or 0.2 percent to 152,482 MW. Capacity resources exceeded capacity obligations every day by an average of 9,531 MW, a decrease of 466 MW from the average net excess of 9,997 MW for the 2005 ComEd PCI period. (See Table 1-5)

- **Demand.** Unforced obligations remained relatively constant in the PJM CCM in 2006 compared to the 2005 ComEd PCI period. Average load obligations increased by 168 MW or 0.1 percent to 142,951 MW. PJM electricity distribution companies (EDCs) and their affiliates maintained a large market share of load obligations in the PJM CCM in 2006, together averaging 87.6, down slightly from 88.5 percent for the 2005 ComEd PCI period. (See Figure 1-5.)

26 For further information on the ComEd PCI period, see *2006 State of the Market Report*, Volume II, Appendix E, "Capacity Market."

Figure 1-5 PJM capacity market load obligation served (Percent): Calendar year 2006



- **Market Concentration.** Structural analysis of the PJM CCM found that, on average, the Daily CCM exhibited moderate concentration levels while the Monthly and Multimonthly CCM exhibited high concentration levels during 2006. The highest market share for any entity in one daily auction was 44.9 percent, while the highest average daily market share for any entity across all of the daily auctions was 28.8 percent. Of 365 daily auctions, 82 (22.5 percent) had a Herfindahl-Hirschman Index (HHI) greater than 1800. HHIs for the longer-term Monthly and Multimonthly CCM averaged 3611, with a maximum of 10000 and a minimum of 1691 (three firms with equal market shares would result in an HHI of 3333). The highest market share for any entity in one monthly/multimonthly auction was 100.0 percent, while the highest average market share for any entity across all of the monthly/multimonthly auctions was 30.5 percent. All but one of the 65 monthly/multimonthly auctions (98.5 percent) had an HHI greater than 1800. The PJM CCM accounted for 6.4 percent of total capacity obligations. The MMU also analyzed ownership in the PJM Capacity Market as a whole in order to develop a more complete assessment of market structure for capacity. Ownership in the PJM Capacity Market exhibited low concentration levels throughout the year, with HHIs at 925 on January 1 and December 31. The highest market share declined from 16.7 percent to 16.4 percent. There was a single pivotal supplier throughout the year, with four individual suppliers who were each pivotal on a stand-alone basis.

- **External and Internal Capacity Transactions.** In 2006, imports averaged 3,093 MW, which was a decrease of 904 MW or 22.6 percent from the 2005 ComEd PCI period average of 3,997 MW. Exports averaged 4,958 MW, which was a decrease of 74 MW or 1.5 percent from the 2005 ComEd PCI period average of 5,032 MW. Average net exchange decreased 830 or 80.2 percent to -1,865 MW from the 2005 ComEd PCI period average of -1,035 MW. Internal bilateral transactions averaged 160,952 MW, which was an increase of 4,581 MW or 2.9 percent from the 156,371 MW average for the 2005 ComEd PCI period.

- **Active Load Management (ALM).** In 2006, ALM credits in the PJM CCM averaged 1,828 MW, down 214 MW (10.5 percent) from 2,042 MW in the 2005 ComEd PCI period. (See Table 1-5.)

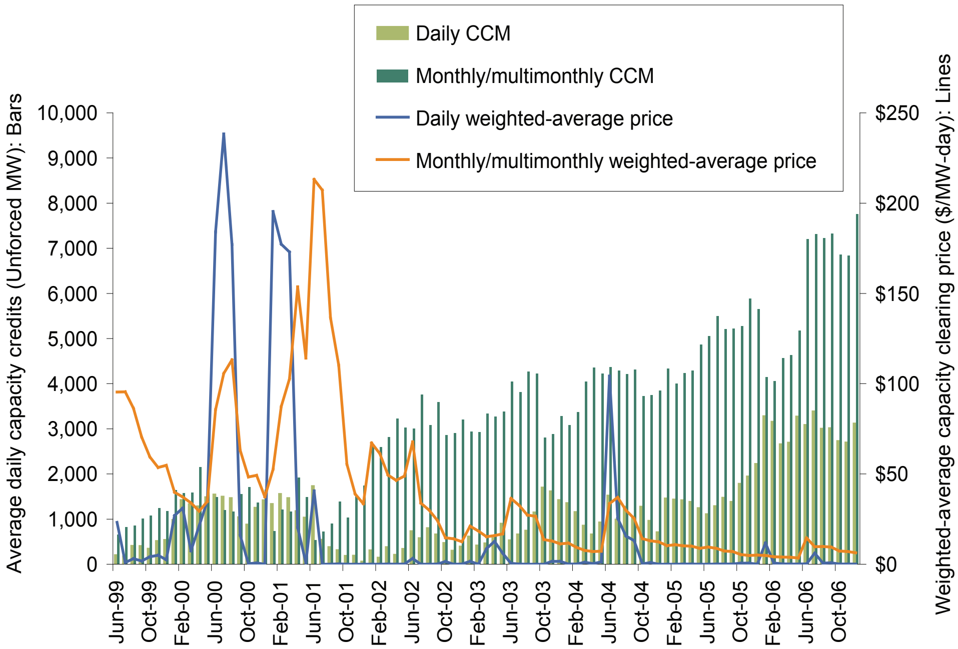
Table 1-5 PJM capacity summary (MW): Calendar year 2006

	Mean	Standard Deviation	Minimum	Maximum
Installed Capacity	162,571	349	162,008	163,097
Unforced Capacity	152,482	186	152,176	152,887
Obligation	142,951	121	142,461	143,152
Sum of Excess	9,531	205	9,037	10,047
Sum of Deficiency	0	0	0	0
Net Excess	9,531	205	9,037	10,047
Imports	3,093	201	2,769	3,333
Exports	4,958	404	4,401	5,668
Net Exchange	(1,865)	560	(2,616)	(1,114)
Unit-Specific Transactions	15,548	504	14,694	16,044
Capacity Credit Transactions	145,404	3,742	140,345	155,060
Internal Bilateral Transactions	160,952	3,543	155,750	170,680
Daily Capacity Credits	3,013	332	2,268	3,962
Monthly Capacity Credits	1,572	382	996	2,067
Multimonthly Capacity Credits	4,533	1,154	2,484	5,783
All Capacity Credits	9,118	1,424	7,103	11,720
ALM Credits	1,828	180	1,642	2,042

Market Performance

- **CCM Volumes and Prices.** During 2006, total PJM CCM transactions averaged 9,118 MW (6.4 percent of obligation), which was 2,113 MW higher than the 2005 ComEd PCI period average of 7,005 MW (4.9 percent of obligation). Total PJM CCM prices averaged $5.73 per MW-day, which was $0.46 per MW-day higher than the 2005 ComEd PCI period average of $5.27 per MW-day. Daily CCM volume declined from 2.5 percent of average obligation in 2000 to 2.1 percent in 2006. Monthly and multimonthly CCM volume increased from 3.0 percent of obligation in 2000 to 4.3 percent of average obligation in 2006. CCM prices increased from 1999 through 2001 and have declined and remained relatively stable since 2001 with the exception of the summers of 2004 and 2006 and the first few days of January 2006. (See Figure 1-6.)

Figure 1-6 PJM Daily and Monthly/Multimonthly CCM performance: June 1999 to December 2006



Generator Performance

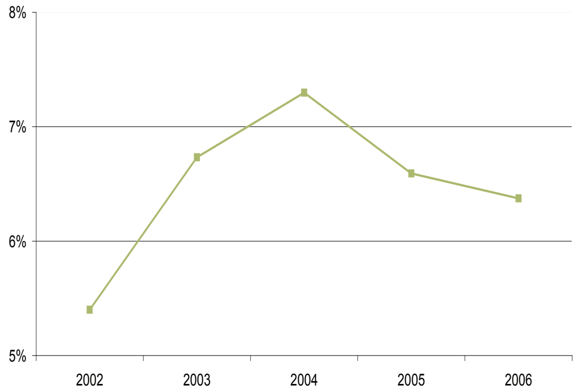
The existence of a capacity market that links payments for capacity to the level of unforced capacity and therefore to the forced outage rate creates an incentive to improve forced outage rates. These incentives are somewhat attenuated in the current capacity market design. The Energy Market also provides incentives for improved performance with somewhat different characteristics. Generators want to maximize their sales of energy when prices are high. If they are successful, this will also result in lower forced outage rates. The design of the RPM provides additional incentives for reduced outages during high-load periods and scarcity pricing could also provide strong, complementary incentives for reduced outages during high-load periods.

As Figure 1-7 shows, from 2002 to 2004, the average PJM equivalent demand forced outage rate (EFORd) increased, from 5.4 percent in 2002 to 6.7 percent in 2003 and 7.3 percent in 2004.[27] In 2005, the average PJM EFORd decreased to 6.6 percent and again decreased in 2006 to 6.4 percent. The decrease in EFORd from 2005 to 2006 was the result of decreased forced outage rates across all unit types with the exception of steam and diesel generators. These forced outage rates are for the entire PJM Control Area.[28]

27 As a general matter, the annual EFORd data presented in state of the market reports may be revised based on final data submitted after the publication of the reports.

28 In some cases, data for the AEP, DAY, DLCO, Dominion and ComEd Control Zones may be incomplete for the years 2002 and 2003. Only data that have been reported to PJM were used.

Figure 1-7 Trends in the in the PJM equivalent demand forced outage rate (EFORd): Calendar years 2002 to 2006[29]



Conclusion

Perhaps the most important fact about the PJM Capacity Market is that it will change significantly in 2007 as the result of the implementation of the RPM capacity market design. The conclusions here are based both on the details of the capacity market structure, conduct and performance under the existing market designs and on the underlying facts about the ownership structure of capacity and the obligations of load. While the detailed conclusions apply primarily to the existing capacity market design, there are significant conclusions that apply to any capacity market design.

The MMU analyzed market structure and market performance in the PJM Capacity Market for calendar year 2006, including supply, demand, concentration ratios, pivotal suppliers, volumes, prices, outage rates and reliability. Given the basic features of market structure in the PJM Capacity Market, including significant market structure issues, inelastic demand, tight supply-demand conditions, 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 continues to be high. Market power is endemic to the existing structure of the PJM Capacity Market.

The RPM capacity market design explicitly addresses the underlying issues of ensuring that competitive prices can reflect local scarcity while not relying on the exercise of market power to achieve the design objective and explicitly limiting the exercise of market power.

The Capacity Market is, by design, always tight in the sense that total supply is generally only slightly larger than demand. This is the case for the existing capacity market design as well as for the RPM. The market may be long at times, but that is not the equilibrium state. Capacity in excess of demand is not sold and, if it does not earn adequate revenues in other markets, will retire. The demand for capacity includes expected peak load plus a reserve margin. Thus, the reliability goal is to have total supply equal to or slightly above the demand for capacity. Demand is almost entirely inelastic because the market rules require loads to purchase their share of the system capacity requirement. The result is that any supplier that owns more capacity than the difference between total supply and the defined demand is pivotal. In PJM, in 2006, the excess supply was 9,531 MW. There were four individual suppliers who were each larger than 9,531 MW and who were, therefore, each pivotal on a stand-alone basis. In other words, the market design for capacity leads, almost unavoidably, to structural market power. This is not surprising in that the Capacity Market is the result of a regulatory/administrative decision to require a specified level of reliability and the related decision to require all load-serving entities to purchase a share of the capacity required to provide that reliability. But, it is important to keep these basic facts in mind when designing and evaluating capacity markets. The capacity market is unlikely ever to approach the economist's view of a competitive market structure in the absence of a substantial and

29 Data for 2002 and 2003 are incomplete for some units in newly integrated areas. Available information supports the conclusion that there is no significant impact on the results of the analysis.

unlikely structural change that results in much more diversity of ownership.[30]

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. This may result from the short-run, net position of individual suppliers with structural market power. 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 in the PJM Capacity Market. 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 2006. The PJM Capacity Market results were competitive during 2006.

The new RPM capacity market design represents a significant advance over the current capacity market design because RPM has explicit market power mitigation rules designed to permit competitive, locational capacity prices while limiting the exercise of market power. The RPM construct appears consistent with the appropriate market design objectives of permitting competitive prices to reflect local scarcity conditions while explicitly limiting market power. The MMU recommends the implementation of the rules included in PJM's filed RPM Tariff 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. The RPM capacity market design explicitly provides that competitive prices can reflect local scarcity while not relying on the exercise of market power to achieve that design objective and explicitly limits the exercise of market power via the application of the three pivotal supplier test.

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 -- synchronized reserve services; and 6) operating reserve -- supplemental reserve services.[31] Of these, PJM currently provides regulation, energy imbalance and synchronized reserve services through market-based mechanisms.[32] PJM provides energy imbalance service through the Real-Time Energy Market. PJM provides the remaining ancillary services on a cost basis.

Regulation matches generation with very short-term changes in load by moving the output of selected generators up and down via an automatic control signal.[33] Regulation is provided, independent of economic signal, by generators with a short-term response capability (less than five minutes) or by DSR.

30 The market could be competitive if there were many more suppliers and all were relatively small compared to the size of the market and the level of excess capacity, but this is unlikely to occur.

31 75 FERC ¶ 61,080 (1996).

32 The term "spinning reserve" has been replaced with "synchronized reserve," consistent with modifications made to PJM manuals. This change reflects the fact that demand-side resources may now provide synchronized reserve and such resources are not literally spinning reserve in every case, as are generators.

33 Regulation is used to help control the area control error (ACE). See *2006 State of the Market Report,* Volume II, Appendix F, "Ancillary Service Markets," for a full definition and discussion of ACE.

Longer-term deviations between system load and generation are met via primary and secondary reserve and generation responses to economic signals. Synchronized reserve is a form of primary reserve. To provide synchronized reserve a generator must be synchronized to the system and capable of providing output within 10 minutes. Synchronized reserve can also be provided by DSR. The term, "synchronized reserve market" refers only to the supply of and demand for Tier 2 synchronized reserve.

Both the Regulation and Synchronized Reserve Markets are cleared on a real-time basis. A unit can be selected for either regulation or synchronized reserve, but it cannot be selected for both. The Regulation and Synchronized Reserve Markets are cleared simultaneously and cooptimized with the Energy Market and operating reserve requirements to minimize the cost of the combined products subject to reactive limits, resource constraints, unscheduled power flows, inter-area transfer limits, resource distribution factors, self-scheduled resources, limited fuel resources, bilateral transactions, hydrological constraints, generation requirements and reserve requirements.

PJM does not provide a market for reactive power, but does ensure its adequacy through member requirements and scheduling.[34] 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.

On August 1, 2005, PJM integrated what had been five regulation control zones into one combined Regulation Market for a trial period. After the trial period and after a report by the MMU, PJM stakeholders will vote on whether to keep the combined market. The MMU provided that report on October 18, 2006, and it is under review by PJM members.[35]

PJM operates four Synchronized Reserve Markets: one for the Mid-Atlantic Region, one for the Western Region, one for the Southern Region (Dominion) and one for the ComEd Control Zone.

Regulation Market

Market Structure

- **Supply.** The supply of offered and eligible regulation in PJM was generally both stable and adequate. Potential regulation supply was enhanced during 2006 by allowing demand-side resources to offer regulation and to satisfy up to 25 percent of the regulation requirement, although no demand-side resources offered regulation during 2006. The ratio of eligible regulation offered to regulation required averaged 2.60 throughout 2006.

- **Demand.** The regulation requirement is set daily for the entire day by PJM to be 1.0 percent of the forecast-peak load for PJM. This requirement was established in August 2006.

- **Market Concentration.** During 2006, the PJM Regulation Market had an average HHI of 1256 which is classified as "moderately concentrated."[36] The largest hourly market share was 40 percent, and 43 percent of all hours had a maximum market share greater than 20 percent. There were no suppliers with annual average market shares greater than, or equal to, 20 percent. Approximately 26 percent of hours had three pivotal suppliers. The MMU concludes from these results that the PJM Combined Regulation Market in 2006 was characterized by structural market power in 26 percent of the hours.

34 See PJM "Manual 11: Scheduling Operations," Revision 29 (August 11, 2006), p. 76.

35 See Market Monitoring Unit, "Analysis of the Combined Regulation Market: August 1, 2005 through July 31, 2006" (October 18, 2006) <http://www.pjm.com/markets/market-monitor/downloads/mmu-reports/20061018-mmu-regulation-market-report.pdf> (76.1 KB).

36 See *2006 State of the Market Report,* Volume II, Section 2, "Energy Market, Part I," at "Market Concentration" for a more complete discussion of concentration ratios and the HHI.

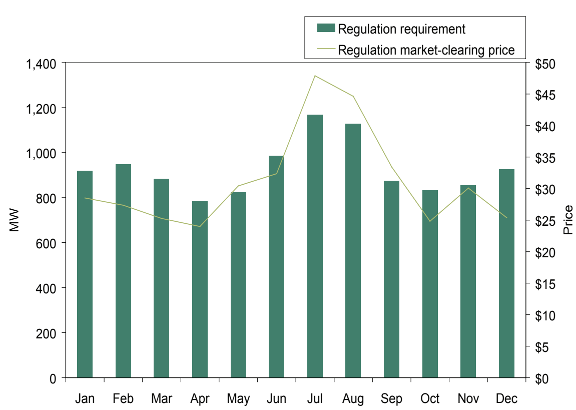
Market Conduct

- **Offers.** The offer price is provided by the unit owner, is applicable for the entire operating day and, with lost opportunity cost (LOC), comprises the total offer to the Regulation Market. The regulation offer price is subject to a $100 per MWh offer cap, with the exception of the dominant suppliers, whose offers are capped at marginal cost plus $7.50 per MWh plus lost opportunity cost. All suppliers are paid the market-clearing price. Based on MMU estimates of the marginal cost of regulation, 33 percent of offers exceeded competitive levels in 2006.

Market Performance

- **Price.** For the PJM Regulation Market during 2006 the average price per MWh (regulation market-clearing price including lost opportunity cost) associated with meeting PJM's demand for regulation was $32.69. This represents a decrease of $19.17 from the average price for regulation during 2005. In 2006, based on MMU estimates of the marginal cost of regulation, offers at levels greater than competitive levels set the clearing price for regulation in about 30 percent of all hours. (See Figure 1-8.)

Figure 1-8 Monthly average regulation demand (required) vs. price: Calendar year 2006



Synchronized Reserve Market

The structure of each Synchronized Reserve Market (the term, "synchronized reserve market" refers only to Tier 2 synchronized reserve) 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. As a result of these requirements, the conduct of market participants within these market structures has been consistent with competition, and the market performance results have been competitive. Prices for synchronized reserve in the PJM Mid-Atlantic Region, the ComEd Control Zone, the Western Region and Southern Region are market-clearing prices determined by the supply curve and the administratively defined demand. The cost-based synchronized reserve offers are defined to be the unit-specific incremental cost of providing synchronized reserve plus a margin of $7.50 per MWh plus lost opportunity cost calculated by PJM.

Market Structure

- **Supply.** For the PJM Mid-Atlantic Synchronized Reserve Region, the offered and eligible excess supply ratio was 1.64. For the ComEd Synchronized Reserve Control Zone, the ratio was 1.46.[37] These excess supply ratios are determined using the administratively required synchronized reserve. The actual requirement for Tier 2 synchronized reserve is lower because there is usually a significant amount of Tier 1 synchronized reserve available. In August 2006 DSR resources began participating in PJM Synchronized Reserve Markets. As of the end of 2006, the MW contribution of DSR resources to the supply of synchronized reserve remained small, but increasing. Market rules limit the contribution of DSR resources to 25 percent of the administratively required synchronized reserve. (See Figure 1-9.)

37 The Synchronized Reserve Markets in the Western Region and Southern Region cleared in so few hours that related data for those markets are not meaningful.

Figure 1-9 PJM Tier 2 synchronized reserve cleared MW: Calendar year 2006

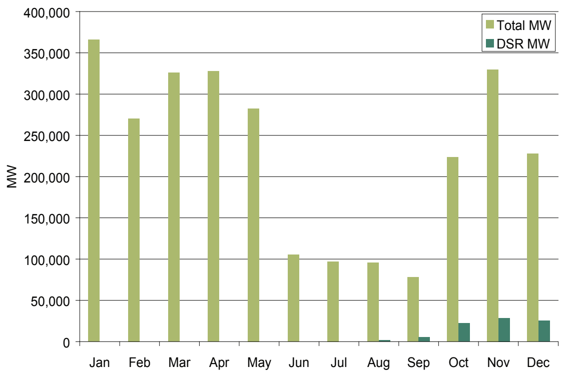
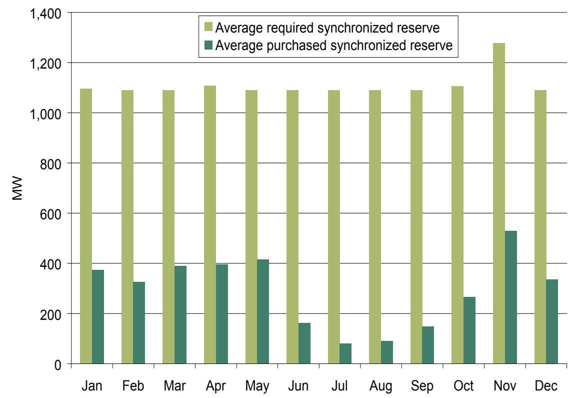


Figure 1-10 PJM Mid-Atlantic Tier 2 Synchronized Reserve Region's monthly required vs. purchased: Calendar year 2006



- **Demand.** The average synchronized reserve requirement was: 1,109 MW for the Mid-Atlantic Synchronized Reserve Region; 222 MW for the ComEd Synchronized Reserve Control Zone; 423 MW for the Western Synchronized Reserve Region; and 9 MW for the Southern Synchronized Reserve Region. These requirements are a function of administratively determined, regional requirements. Market demand is less than the requirement by the amount of Tier 1 synchronized reserve available at the time a Synchronized Reserve Market is cleared. The average demand for synchronized reserve was: 293 MW for the Mid-Atlantic Synchronized Reserve Region; 59 MW for the ComEd Synchronized Reserve Control Zone; 0 MW for the Southern Synchronized Reserve Region; and 3 MW for the Western Synchronized Reserve Region. (See Figure 1-10.)

- **Market Concentration.** In 2006, market concentration was high in the Tier 2 Synchronized Reserve Markets. The average cleared synchronized reserve market HHI for the Mid-Atlantic Synchronized Reserve Region throughout 2006 was 5686. The average HHI for the ComEd Synchronized Reserve Control Zone was 8305. The average HHI for the Western Synchronized Reserve Region was 7944. The HHI for the Southern Synchronized Reserve Region was always 10000.

Market Conduct

- **Offers.** The offer price is provided by the unit owner, is applicable for the entire operating day and, with lost opportunity cost calculated by PJM, comprises the total offer price to the Synchronized Reserve Market. The synchronized reserve offer made by the unit owner is subject to an offer cap of marginal cost plus $7.50 per MWh, plus lost opportunity cost. All suppliers are paid the higher of the market-clearing price or their offer plus their unit-specific opportunity cost.

Market Performance

- **Price.** The load-weighted, average PJM price for Tier 2 synchronized reserve was $14.94 per MW in 2006, a $0.53 per MW increase from 2005. The load-weighted, average price in 2006 for Tier 2 synchronized reserve was $14.57 per MW in the Mid-Atlantic Synchronized Reserve Region, $16.69 in the ComEd Synchronized Reserve Control Zone, $9.14 in the Western Synchronized Reserve Region and $23.49 in the Southern Synchronized Reserve Region.

Conclusion

PJM consolidated its Regulation Markets into a single Combined Regulation Market, on a trial basis, effective August 1, 2005. The MMU concludes from the analysis of the 2006 data that the PJM Regulation Market in 2006 was characterized by structural market power in 26 percent of the hours.[38] This conclusion is based on the results of the three pivotal supplier test. The MMU also concludes that PJM's consolidation of its Regulation Markets resulted in improved performance and in increased competition compared to the PJM Mid-Atlantic Regulation Market or the Western Region Regulation Market on a stand-alone basis.[39] The MMU also concludes that the performance of the Regulation Market was more competitive in calendar year 2006 than during the first 12 months of the Regulation Market, August 1, 2005, through July 31, 2006. These conclusions are based on improved HHI results and fewer hours during which there were three pivotal suppliers. The combined market results include the effects of the current mitigation mechanism which offer caps the two dominant suppliers in every hour. The MMU concludes that it would be preferable to retain the existing, experimental single PJM Regulation Market as the long-term market if appropriate mitigation can be implemented that addresses only the hours in which structural market power exists and which therefore provides an incentive for the continued development of competition.

With respect to mitigation, the MMU recommends that real-time, hourly market structure tests be implemented in the Regulation Market; that market power mitigation be applied only for hours in which the market structure is noncompetitive, and that market power mitigation be applied only to the companies failing the market structure tests. More specifically, the MMU recommends that the three pivotal supplier test be applied hourly in the Regulation Market using a market definition of all eligible offers less than or equal to 1.50 times the clearing price and that mitigation be applied to only those regulation-owning companies that fail the test in that hour.[40]

This more flexible and real-time approach to mitigation represents an improvement over the current approach to mitigation which requires cost-based offers from the dominant companies at all times. The proposed approach to mitigation also represents an improvement over prior methods of simply defining the market to be noncompetitive and limiting all offers to cost-based offers. The real-time approach recognizes that at times the market is structurally competitive and therefore no mitigation is required; that at times the market is not structurally competitive and mitigation is required, and that at times generation owners other than the designated dominant suppliers may have structural market power that requires mitigation. The MMU also recommends that the overall $100 regulation offer cap remain in effect. The retention of an overall offer cap together with a real-time, three pivotal supplier test for market structure is identical to PJM's current practice in the Energy Market.

The conclusions related to the structure of the Regulation Market are consistent with the conclusions reached in the *2005 State of the Market Report,* which stated: "The structure of the Mid-Atlantic Region and

38 This is the same conclusion reached in the MMU report on the first year of the Combined Regulation Market. See Market Monitoring Unit, "Analysis of the Combined Regulation Market: August 1, 2005 through July 31, 2006" (October 18, 2006) <http://www.pjm.com/markets/market-monitor/downloads/mmu-reports/20061018-mmu-regulation-market-report.pdf> (76.1 KB).

39 *2005 State of the Market Report* (March 8, 2006), pp. 260-263.

40 See *2006 State of the Market Report*, Volume II, Appendix J, "Three Pivotal Supplier Test."

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 2005 report also stated, "The Regulation Markets produced competitive results throughout calendar year 2005 based on the regulation market-clearing price."[41] The MMU cannot conclude that the Regulation Market in 2006 produced competitive results or noncompetitive results, based on our analysis of the relationship between the offer prices and marginal costs of units providing regulation. That is one of the reasons that the MMU recommends that all suppliers be required to provide cost-based regulation offers as part of real-time market power mitigation.

PJM's Synchronized 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 these approaches to Ancillary Service Markets. Even in the presence of structurally noncompetitive markets, there can be transparent, market-clearing prices based on competitive offers that account explicitly and accurately for opportunity costs. This is consistent with the market design goal of ensuring competitive outcomes that provide appropriate incentives without reliance on the exercise of market power and with explicit mechanisms to prevent the exercise of market power.

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.

Overall, the MMU concludes that the Regulation Market's results cannot be determined to have been competitive or to have been noncompetitive. The MMU concludes that the Synchronized Reserve Markets' results were competitive.

Congestion

Congestion occurs when available, least-cost energy cannot be delivered to all loads for a period because transmission facilities are not adequate to deliver that energy to some loads. When the least-cost available energy cannot be delivered to load in a transmission-constrained area, higher cost units in the constrained area must be dispatched to meet that load.[42] 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. Locational marginal prices (LMPs) reflect the price of the lowest-cost resources available to meet loads, taking into account actual delivery constraints imposed by the transmission system. Thus LMP is an efficient way to price energy 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 good nor bad but is a direct measure of the extent to which there are differences in the cost of generation that cannot be equalized because of transmission constraints. A complete set of markets would permit direct competition between investments in transmission and generation. The transmission system provides a 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, ARRs/FTRs are

41 *2005 State of the Market Report* (March 8, 2006), pp. 250-251.

42 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.

not guaranteed to be a complete hedge against congestion, ARRs/FTRs do provide a substantial offset to the cost of congestion to firm load.[43]

Congestion Cost

- **Total Congestion.** Total congestion costs decreased by $489 million or 23 percent, from $2.092 billion in calendar year 2005 to $1.603 billion in calendar year 2006. Day-ahead congestion costs decreased by $650 million or 28 percent, from $2.357 billion in calendar year 2005 to $1.707 billion in calendar year 2006. Balancing congestion costs increased by $161 million or 61 percent, from -$265 million in calendar year 2005 to -$104 million in calendar year in 2006. Total congestion costs have ranged from 7 percent to 10 percent of PJM annual total billings since 2002. Congestion costs were 8 percent of total PJM billings for 2006, compared to 9 percent in 2005. Total PJM billings for 2006 were $20.945 billion, a 7 percent decrease from the $22.630 billion billed in 2005. (See Table 1-6.)

Table 1-6 Total annual PJM congestion [Dollars (millions)]: Calendar years 2002 to 2006

	Congestion Charges	Percent Change	Total PJM Billing	Percent of PJM Billing
2002	$453	NA	$4,700	10%
2003	$464	2%	$6,900	7%
2004	$750	62%	$8,700	9%
2005	$2,092	179%	$22,630	9%
2006	$1,603	(23%)	$20,945	8%
Total	$5,362		$63,875	8%

- **Monthly Congestion.** Fluctuations in monthly congestion costs continued to be substantial. In 2006, 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.** The total of ARR and FTR revenues hedged 99 percent of the congestion costs in the Day-Ahead and Balancing Energy Market within PJM for the 2005 to 2006 planning period and 98.4 percent of the congestion costs in PJM in the first seven months of the 2006 to 2007 planning period.[44] The total value of the hedge provided by FTRs reflects the fact that FTRs were paid at 91 percent of the target allocation level for the 12-month planning period that ended May 31, 2006. FTRs were paid at 100 percent of the target allocation level through December 31, 2006, for the planning period ending May 31, 2007. ARR and FTR revenue adequacy results are aggregate results and all those paying congestion charges were not necessarily hedged at that level as aggregate numbers do not reveal the underlying distribution of FTR holders, their revenues or those paying congestion.

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 as the difference between zonal LMP and the Western Hub LMP. Price separation between eastern and western control zones in PJM was primarily a result of congestion on the Bedington-Black Oak Interface, the Kammer and Wylie Ridge transformers and the 5004/5005 Interface. These constraints generally had the effect of increasing prices in eastern control zones located on the constrained side of the affected facilities while reducing prices in the unconstrained western control zones.

43 See *2006 State of the Market Report*, Volume II, Section 8, "Financial Transmission and Auction Revenue Rights," at "ARR and FTR Revenue and Congestion."

44 See *2006 State of the Market Report*, Volume II, Section 8, "Financial Transmission and Auction Revenue Rights," at Table 8-20, "ARR and FTR congestion hedging: Planning periods 2005 to 2006 and 2006 to 2007."

- **Congested Facilities.** As was the case in 2005, congestion frequency was significantly higher in the Day-Ahead as compared to the Real-Time Market in 2006.[45] Day-ahead congestion frequency increased slightly in calendar year 2006 as compared to 2005. In 2006, there were 56,299 day-ahead, congestion-event hours as compared to 55,705 congestion-event hours in 2005. Day-ahead, congestion-event hours increased on lines and Midwest Independent Transmission System Operator, Inc. (Midwest ISO) flowgates, while transformers and interfaces saw decreases. Real-time congestion frequency decreased in calendar year 2006 as compared to 2005. In 2006, there were 19,510 real-time, congestion-event hours as compared to 24,109 congestion-event hours in 2005. Real-time, congestion-event hours increased on Midwest ISO flowgates, while lines, transformers and interfaces saw decreases. The Bedington – Black Oak Interface was the largest contributor to congestion costs in both 2005 and 2006 and, with $492 million in total congestion costs, accounted for 31 percent of the total PJM congestion costs in 2006. The top four constraints in terms of congestion costs together contributed $780 million, or 49 percent, of the total PJM congestion costs in 2006. The top four constraints also included the 5004/5005 Interface, Mount Storm – Pruntytown and Kanawha – Matt Funk lines. (See Table 1-7.)

Table 1-7 Congestion summary (By facility type): Calendar years 2005 to 2006

	2005				2006			
	Event Hours		Congestion Costs (Millions)		Event Hours		Congestion Costs (Millions)	
Type	Day Ahead	Real Time	Day Ahead	Balancing	Day Ahead	Real Time	Day Ahead	Balancing
Flowgate	824	359	$8.8	$6.4	1,350	859	$5.2	($11.2)
Interface	11,738	3,910	$1,073.3	($50.6)	8,273	2,792	$752.4	$11.6
Line	30,819	12,253	$636.3	($132.3)	34,558	11,447	$585.5	($89.6)
Transformer	12,324	7,587	$626.8	($88.4)	12,118	4,412	$349.2	($14.6)
Unclassified	NA	NA	$11.6	$0.0	NA	NA	$14.9	$0.0
Total	55,705	24,109	$2,356.8	($264.9)	56,299	19,510	$1,707.1	($103.8)

45 Prior state of the market reports measured real-time congestion frequency using the convention that a congestion-event hour exists if the particular facility is constrained for four or more of the 12 five-minute intervals comprising that hour. In the *2006 State of the Market Report*, in order to have a consistent metric for real-time and day-ahead congestion frequency, real-time congestion frequency is measured using the convention that an hour is constrained if any of its component five-minute intervals is constrained. Comparisons to previous periods use the new standard for both current and prior periods.

- **Zonal Congestion.** In calendar year 2006, the AP Control Zone experienced the highest congestion cost of any control zone in PJM. The $340 million in congestion costs in the AP Control Zone represented a 26 percent decrease from the $460 million in congestion costs the zone had experienced in 2005. The Bedington – Black Oak Interface and Meadow Brook transformer constraints together contributed $208 million, or 61 percent of the total AP Control Zone congestion cost. The AEP Control Zone had the second highest congestion cost in PJM in 2006. The $242 million in congestion costs in the AEP Control Zone represented an 18 percent increase from the $204 million in congestion costs the zone had experienced in 2005. The Kanawha – Matt Funk line and the Bedington – Black Oak Interface constraints together contributed $104 million, or 43 percent of the total AEP Control Zone congestion cost. (See Table 1-8.)

Table 1-8 Congestion cost summary (By zone): Calendar years 2005 to 2006

	Congestion Costs (Millions)					
	2005			2006		
Control Zone	Day Ahead	Balancing	Total	Day Ahead	Balancing	Total
AECO	$70.4	$13.5	$83.8	$62.0	$5.3	$67.2
AEP	$351.2	($147.0)	$204.2	$302.1	($60.4)	$241.7
AP	$508.7	($48.9)	$459.9	$379.4	($39.3)	$340.1
BGE	$44.4	$52.8	$97.1	$64.3	$40.7	$105.0
ComEd	$60.5	$140.5	$201.0	$87.6	$61.3	$149.0
DAY	$31.5	($16.6)	$14.9	$21.8	($8.1)	$13.6
DLCO	$94.3	($50.9)	$43.4	$50.2	($21.8)	$28.4
Dominion	$236.1	($55.6)	$180.5	$259.4	($34.7)	$224.7
DPL	$109.3	$8.8	$118.1	$72.7	$14.5	$87.3
JCPL	$153.3	$9.2	$162.4	$94.8	$1.1	$95.9
Met-Ed	$38.4	($10.7)	$27.7	$27.3	($13.2)	$14.2
PECO	$33.5	($55.5)	($22.0)	($26.7)	($27.6)	($54.3)
PENELEC	$158.4	($3.7)	$154.7	$113.7	($10.3)	$103.4
PEPCO	$191.1	$1.6	$192.7	$155.3	$25.7	$181.0
PJM	$96.3	($61.3)	$34.9	($36.0)	($17.6)	($53.7)
PPL	($52.0)	($15.8)	($67.8)	($31.7)	($6.0)	($37.7)
PSEG	$212.7	($23.3)	$189.4	$99.4	($13.9)	$85.6
RECO	$18.8	($1.9)	$16.9	$11.5	$0.5	$12.0

Economic Planning Process

- **Process Revision.** PJM's current planning process for economic transmission expansions provides that when unhedgeable congestion reaches certain thresholds, a one-year market window is opened during which time market solutions may be proposed by market participants. In its September 8, 2006, filing, PJM proposed to replace the unhedgeable congestion approach with an evaluation based on additional congestion metrics. The metrics will be applied to evaluating all types of transmission projects, including whether to modify or accelerate reliability enhancements already in the Regional Transmission Expansion Plan (RTEP) that could also relieve one or more economic constraints and whether to propose new, economic transmission projects that could relieve one or more economic constraints. PJM will also evaluate whether demand response resources or new generation could eliminate the need for an economic upgrade. The revised economic planning process includes enhanced stakeholder participation. The proposed economic planning revisions incorporate improvements over the existing process but require ongoing development. The approach to weighting and evaluating the metrics in the context of actual transmission projects will require substantial effort. New transmission projects, and the lack of existing transmission, can have significant impacts on the PJM markets and the goal of transmission planning should ultimately be the incorporation of transmission investment decisions into market-driven processes as much as is practicable.

Conclusion

Congestion reflects the underlying characteristics of the power system, including the nature and capability of transmission facilities and the cost and geographical distribution of generation facilities. Total congestion costs decreased by $489 million or 23 percent, from $2.092 billion in calendar year 2005 to $1.603 billion in calendar year 2006. Day-ahead congestion costs decreased by $650 million or 28 percent, from $2.357 billion in calendar year 2005 to $1.707 billion in calendar year 2006. Balancing congestion costs increased by $161 million or 61 percent, from -$265 million in calendar year 2005 to -$104 million in calendar year in 2006. Congestion costs were significantly higher in the Day-Ahead Market than in the Balancing Market. Congestion frequency was also significantly higher in the Day-Ahead Market than in the Real-Time Market. In the Day-Ahead Market in 2006, there were 56,299 congestion-event hours compared to 55,705 congestion-event hours in 2005. In the Real-Time Energy Market in 2006, there were 19,510 congestion-event hours compared to 24,109 congestion-event hours in 2005.

As a result of the geographic growth of PJM, efficient redispatch displaced the less efficient management of borders via transmission loading relief (TLR) procedures and ramp limits. Redispatch is more efficient and, at the same time, revealed the underlying inability of the transmission system 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 over the broad PJM footprint for the first time, is an essential input to a rational market and planning process. PJM has made significant steps in the transmission planning process.

ARRs and FTRs served as an effective hedge against congestion. In total, ARR and FTR revenues hedged 99 percent of congestion costs in the Day-Ahead and Balancing Energy Market within PJM for the 2005 to 2006 planning period and 98.4 percent of the congestion costs in PJM in the first seven months of the 2006 to 2007 planning period. FTRs were paid at 91 percent of their target allocation for the planning year ended May 31, 2006, and at 100 percent for the first seven months of the current planning year.

One constraint accounted for almost a third of total congestion costs in 2006 and the top four constraints accounted for about half of total congestion costs. The largest constraint has been a persistent source of large congestion costs for several years. This suggests that these constraints should receive special attention in the economic planning process. The Bedington – Black Oak Interface was the largest contributor to congestion costs in both 2005 and 2006 and, with $492 million in total congestion costs, accounted for 31 percent of the total PJM congestion costs in 2006. The top four constraints in terms of congestion costs together accounted for 49 percent of the total PJM congestion costs in 2006.

Financial Transmission and Auction Revenue Rights

FTRs and ARRs give firm transmission customers an offset against congestion costs. An FTR provides holders revenues, or charges, equal to the difference in prices in the Day-Ahead Energy Market across the specific FTR transmission path. An ARR is a related product that provides holders revenues, or charges, based on the price differences across the specific ARR transmission path that result from the Annual FTR Auction. FTRs and ARRs provide a hedge against congestion costs, but neither FTRs nor ARRs provide a guarantee that firm transmission customers will not pay congestion charges. 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.

In PJM, FTRs have been 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.[46] Effective June 1, 2003, PJM replaced the allocation of FTRs with an allocation of ARRs and an associated Annual FTR Auction.[47] Firm transmission customers can take allocated ARRs or the underlying FTRs through a process called self-scheduling.

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

The *2006 State of the Market Report* focuses on two FTR/ARR planning periods: the 2005 to 2006 planning period which covers June 1, 2005, through May 31, 2006, and the 2006 to 2007 planning period which covers June 1, 2006, through May 31, 2007.[48]

FTRs

Market Structure

- **Supply.** PJM operates an Annual FTR Auction for all control zones in the PJM footprint. In addition to the Annual FTR Auction, PJM conducts regular monthly Balance of Planning Period FTR Auctions for the remaining months of the planning period, to allow participants to buy and sell any residual transmission capability.[49] FTR products include FTR obligations and FTR options. Each of these is available for 24-hour, on-peak and off-peak periods. FTRs have terms varying from one month to one year. PJM submitted to the FERC revisions to the PJM Open Access Transmission Tariff (OATT) to include long-term ARRs and FTRs that would be in effect for 10 planning periods.[50] Long-term FTRs would be obtained by directly converting long-term ARRs into self-scheduled FTRs. FTR supply is limited by the capability of the transmission system to accommodate simultaneously the set of requested FTRs and the numerous combinations of FTRs. The principal

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

47 87 FERC ¶ 61,054 (1999).

48 Annual FTR accounting changed from calendar year to planning period beginning with the 2003 to 2004 planning period. Transition to this new accounting period required that 2003 calendar year accounting be extended by five months and encompass January 1, 2003, through May 31, 2004.

49 The monthly Balance of Planning Period FTR Auctions for the 2006 to 2007 planning period are referred to as Monthly FTR Auctions in any figure, table or text that also contains data for Monthly FTR Auctions prior to June 2006.

50 *PJM Interconnection, L.L.C.*, PJM Interconnection, L.L.C. submits revisions to the Amended and Restated Operating Agreement, Docket No. ER06-1218-000 (July 3, 2006).

binding constraints limiting the supply of FTRs in the Annual FTR Auction for the 2006 to 2007 planning period include the Laurel–Woodstown line and the Bedington-Black Oak Interface. Prorating of FTRs is in direct proportion to the MW level requested and in inverse proportion to the effect on the binding constraints.

- **Demand.** There is no limit on FTR demand in any FTR auction. When a new control zone is integrated into PJM, the participants in that control zone must choose to receive either an FTR allocation or an ARR allocation before the start of the Annual FTR Auction for two consecutive years following their integration date. In the Annual FTR Auction for the 2006 to 2007 planning period, total demand was 1,608,422 MW, up from 871,841 MW during the 2005 to 2006 planning period. The Annual FTR Auction cleared 168,167 MW (10.5 percent of demand), leaving 1,440,255 MW (89.5 percent of demand) of uncleared bids. In the monthly Balance of Planning Period FTR Auctions for the first seven months (June through December 2006) of the 2006 to 2007 planning period, the total demand was 6,331,707 MW. The monthly Balance of Planning Period FTR Auctions cleared 380,147 MW (6 percent of demand), leaving 5,951,560 MW (94 percent of demand) of uncleared bids.

- **Market Concentration.** Ownership of FTR products is moderately concentrated and maximum market shares exceed 20 percent in some cases based on the results of the Annual FTR Auction. The FTR options market is more concentrated than the market for FTR obligations. Given PJM's Annual and monthly Balance of Planning Period FTR Auctions, the market shares may fluctuate when FTR-owning entities trade, buy or sell the instruments. The level of concentration is only descriptive and is not a measure of the competitiveness of FTR market structure as the ownership positions resulted from a competitive auction.

Market Performance

- **Volume.** Of 1,652,218 MW in annual FTR requests, including FTR allocations, for the 2006 to 2007 planning period, 208,068 MW (12.6 percent) were cleared. Of 914,483 MW in annual FTR requests for the 2005 to 2006 planning period, 180,608 MW (19.7 percent) were cleared. This volume included the demand and supply for directly allocated FTRs for the AEP, DAY, DLCO and Dominion Control Zones.

- **Price.** For the 2006 to 2007 planning period, 87.2 percent of the Mid-Atlantic Region, AP and ComEd Control Zones' annual FTRs were purchased for less than $1 per MWh and 91.5 percent for less than $2 per MWh. For the 2006 to 2007 planning period, the weighted-average prices paid for annual buy-bid FTR obligations were $1.95 per MWh for 24-hour FTRs and $0.78 per MWh for both on-peak and off-peak FTRs. Comparable, weighted-average prices for the 2005 to 2006 planning period were $1.63 per MWh for 24-hour, $0.45 per MWh for on-peak and $0.19 per MWh for off-peak FTRs. The weighted-average prices paid for 2006 to 2007 planning period annual buy-bid FTR obligations and options were $1.12 per MWh and $0.29 per MWh, respectively, compared to $0.79 per MWh and $0.21 per MWh, respectively, in the 2005 to 2006 planning period.[51] The weighted-average price paid in the monthly Balance of Planning Period FTR Auctions for the first seven months (June through December 2006) of the 2006 to 2007 planning period was $0.29 per MWh, compared with $0.23 per MWh in the Monthly FTR Auctions for the 2005 to 2006 planning period.

51 Weighted-average prices for FTRs in the Annual FTR Auction and monthly Balance of Planning Period FTR Auctions for the 2006 to 2007 planning period are the average prices weighted by the MW and hours in a time period (planning period or month) for each FTR class type: 24-hour, on peak and off peak.

- **Revenue.** Congestion revenues are allocated to FTR holders based on FTR target allocations. PJM collected $1,117 million of FTR revenues during the first seven months (June through December 2006) of the 2006 to 2007 planning period and $2,219 million during the 12-month 2005 to 2006 planning period.[52]

- **Revenue Adequacy.** FTRs were 91 percent revenue adequate for the 2005 to 2006 planning period. FTRs were paid at 100 percent of the target allocation level for the first seven months (June through December 2006) of the 2006 to 2007 planning period.[53] For the first seven months of the 2006 to 2007 planning period, the top sink and top source with the highest positive FTR target allocations were the AP Control Zone and the Western Hub, respectively. Similarly, the top sink and top source with the largest negative FTR target allocations were the Western Hub and the Eastern Hub, respectively.

ARRs

Market Structure

- **Supply.** ARR supply is limited by the capability of the transmission system to simultaneously accommodate the set of requested ARRs and the numerous combinations of ARRs that are feasible. PJM submitted to the FERC revisions to the PJM OATT to include long-term ARRs for a duration of 10 planning periods.[54]

- **Demand.** Total demand in the annual ARR allocation was 99,412 MW for the 2006 to 2007 planning period with 56,705 MW bid in Stage 1 and 42,707 MW bid in Stage 2. This is up from 84,088 MW for the 2005 to 2006 planning period with 50,955 MW bid in Stage 1 and 33,133 MW bid in Stage 2.[55] ARR demand is limited by the total amount of network and long-term, firm point-to-point transmission service.

- **ARR Reassignment for Retail Load Switching.** When retail load switches among LSEs, a proportional share of the ARRs and their associated revenue are reassigned from the LSE losing load to the LSE gaining load. ARR reassignment occurs only if the LSE losing load has ARRs with a net positive economic value. An LSE gaining load in the same zone is allocated a proportional share of positively valued ARRs within the zone based on the shifted load. There were 15,358 MW of ARRs associated with $307,500 per MW-day of revenue that were reassigned in the first seven months (June through December 2006) of the 2006 to 2007 planning period.

Market Performance

- **Volume.** Of 99,412 MW in ARR requests for the 2006 to 2007 planning period, 67,568 MW (68 percent) were allocated. There were 54,430 MW allocated in Stage 1 and 13,138 MW allocated in Stage 2. Eligible market participants self-scheduled 38,301 MW (56.7 percent) of these allocated ARRs as annual FTRs. Demand for ARRs increased because of load growth and the eligibility of the ComEd Control Zone to take ARR allocations, instead of direct allocation FTRs. Of 84,088 MW in ARR requests for the 2005 to 2006 planning period, 59,410 MW (70.7 percent) were allocated. There were 49,577 MW allocated in Stage 1 and 9,833 MW allocated in Stage 2. Eligible market participants self-scheduled 32,631 MW (54.9 percent) of these allocated ARRs as annual FTRs.

52 See *2006 State of the Market Report,* Volume II, Section 7, "Congestion," at Table 7-5, "Monthly PJM congestion accounting summary [Dollars (millions)]: By planning period."

53 See *2006 State of the Market Report*, Volume II, Section 7, "Congestion," at Table 7-5, "Monthly PJM congestion accounting summary [Dollars (millions)]: By planning period" for an additional discussion of FTR revenue adequacy.

54 *PJM Interconnection, L.L.C.*, PJM Interconnection, L.L.C. submits revisions to the Amended and Restated Operating Agreement, Docket No. ER06-1218-000 (July 3, 2006).

55 The demand for the 2005 to 2006 planning period was listed as 82,343 MW in the *2005 State of the Market Report.* This number excluded individual ARR bid requests that did not clear any MW.

- **Revenue.** As ARRs are allocated to qualifying customers rather than sold, there is no ARR revenue comparable to the revenue that results from the FTR auctions.

- **Revenue Adequacy.** During the 2005 to 2006 planning period, ARR holders received $870 million in ARR credits, with an average hourly ARR credit of $1.67 per MWh. During the 2005 to 2006 planning period, the ARR target allocations were $870 million while PJM collected $898 million from the combined Annual and Monthly FTR Auctions, making ARRs revenue adequate. During the 2006 to 2007 planning period, ARR holders will receive $1,405 million in ARR credits, with an average hourly ARR credit of $2.37 per MWh. For the 2006 to 2007 planning period, the ARR target allocations were $1,405 million while PJM collected $1,432 million from the combined Annual and monthly Balance of Planning Period FTR Auctions through the end of calendar year 2006, making ARRs revenue adequate.

- **ARR Proration Issues.** When ARRs were allocated for the 2006 to 2007 planning period, some of the requested ARRs were prorated as a result of binding transmission constraints. For the 2006 to 2007 planning period, one of the major constraints affecting the allocation of ARRs was the Bedington-Black Oak Interface which usually has power flow from the west to the east. Over 700 MW of Stage 1 ARRs were denied to participants whose requested ARRs affected that transmission constraint. On August 1, 2006, two municipalities, the Borough of Chambersburg, Pennsylvania, and the Town of Front Royal, Virginia, filed a complaint with the FERC for review of the proration of their requested ARRs.[56] PJM filed an answer to the complaint on August 23, 2006.[57] The FERC denied the complaint on November 22, 2006.[58]

- **ARR and FTR Revenue and Congestion.** The effectiveness of ARRs and FTRs as a hedge against actual congestion can be measured several ways. The first is to compare the revenue received by ARR holders against the congestion costs experienced by these ARR holders. The second is to compare the revenue received by FTR holders against the total congestion costs within PJM. The final and comprehensive method is to compare the revenue received by all ARR and FTR holders to total actual congestion costs in the Day-Ahead and Balancing Energy Market within PJM. During the 2005 to 2006 planning period, total ARR and FTR revenues hedged 99 percent of the congestion costs within PJM. For the first seven months (June through December 2006) of the 2006 to 2007 planning period, all ARRs and FTRs hedged 98.4 percent of the congestion costs within PJM. (See Table 1-9.)

56 *Front Royal, Town of*, Complaint of the Borough of Chambersburg, PA, and the Town of Front Royal, VA, against PJM Interconnection, L.L.C., Docket No. EL06-94-000 (August 1, 2006).

57 *Front Royal, Town of*, Answer of PJM Interconnection, L.L.C. to complaint, Docket No. EL06-94-000 (August 23, 2006).

58 117 FERC ¶ 61,219 (2006).

Table 1-9 ARR and FTR congestion hedging by control zone: Planning period 2005 to 2006

Control Zone	ARR Credits	FTR Credits	FTR Auction Revenue	Total ARR and FTR Hedge	Congestion	Total Hedge - Congestion Difference
AECO	$31,276,088	$45,920,643	$42,074,184	$35,122,547	$85,668,131	($50,545,584)
AEP	$16,585,860	$441,211,478	($15,723,909)	$473,521,247	$280,012,369	$193,508,878
AP	$361,469,998	$555,983,348	$286,893,310	$630,560,036	$483,593,991	$146,966,045
BGE	$34,661,561	$99,105,743	$38,738,484	$95,028,820	$120,054,110	($25,025,290)
ComEd	$18,303,358	($1,114,514)	$6,699,398	$10,489,446	$211,614,849	($201,125,403)
DAY	$530,510	($4,941,077)	($1,360,475)	($3,050,092)	$17,881,685	($20,931,777)
DLCO	$4,975,801	($8,712,557)	($2,058,290)	($1,678,466)	$43,665,845	($45,344,311)
Dominion	$15,272,576	$303,302,735	$2,301,529	$316,273,782	$235,274,973	$80,998,809
DPL	$21,623,521	$31,778,673	$68,793,242	($15,391,048)	$122,049,540	($137,440,588)
JCPL	$37,324,433	$45,242,267	$51,158,477	$31,408,223	$157,969,491	($126,561,268)
Met-Ed	$26,625,842	$67,782,208	$40,371,152	$54,036,898	$27,068,919	$26,967,979
PECO	$106,838,594	$115,947,529	$118,291,396	$104,494,727	($68,894,565)	$173,389,292
PENELEC	$20,595,178	$32,497,904	$3,022,325	$50,070,757	$132,652,047	($82,581,290)
PEPCO	$18,332,199	$233,047,816	$69,380,488	$181,999,527	$232,932,481	($50,932,954)
PJM	$2,106,635	$23,394,836	$1,702,640	$23,798,831	($1,896,592)	$25,695,423
PPL	$55,370,821	$58,023,715	$50,806,886	$62,587,650	($76,131,684)	$138,719,334
PSEG	$97,257,083	$169,053,611	$133,431,947	$132,878,747	$182,384,671	($49,505,924)
RECO	$1,163,157	$2,949,755	$3,392,076	$720,836	$17,996,930	($17,276,094)
Total	$870,313,215	$2,210,474,113	$897,914,860	$2,182,872,468	$2,203,897,191	($21,024,723)

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 and the monthly Balance of Planning Period FTR Auctions provide a market valuation of FTRs. The FTR Auction Market results for the 2006 to 2007 planning year were competitive and succeeded in providing all qualified market participants with equal access to FTRs. The rules for ARR reassignment when load shifts should address the fact that in the case of ARRs self-scheduled as FTRs, the underlying FTRs do not follow the load while the ARR does. ARRs were 100 percent revenue adequate for both the 2005 to 2006 and the 2006 to 2007 planning periods. FTRs were paid at 91 percent of the target allocation level for the 12-month period of the 2005 to 2006 planning period, and at 100 percent of the target allocation level for the first seven months (June through December 2006) of the 2006 to 2007 planning period. The total of ARR and FTR revenues hedged 99 percent of the congestion costs in the Day-Ahead and Balancing Energy Market within PJM for the 2005 to 2006 planning period and 98.4 percent of the congestion costs in PJM in the first seven months of the 2006 to 2007 planning period. The ARR and FTR revenue adequacy results are aggregate results and 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.

Revenue adequacy must be distinguished from the adequacy of FTRs as a hedge against congestion. Revenue adequacy is a narrower concept that compares the revenues available to cover congestion across specific paths for which FTRs were available and purchased. The adequacy of FTRs as a hedge against congestion compares FTR revenues to total congestion on the system as a measure of the extent to which FTRs hedged market participants against actual, total congestion across all paths, regardless of the availability or purchase of FTRs.