2007 State of the Market Report

VOLUME 2: DETAILED ANALYSIS

MARKET MONITORING UNIT

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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 *2007 State of the Market Report* is the tenth 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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SECTION 1 – INTRODUCTION

The PJM Interconnection, L.L.C. operates a centrally dispatched, competitive wholesale electric power market that, as of December 31, 2007, had installed generating capacity of 163,498 megawatts (MW) and more than 500 market buyers, sellers and traders of electricity in a region including approximately 51 million people in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia.[1] 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.

PJM Market Background

PJM operates the Day-Ahead Energy Market, the Real-Time Energy Market, the Reliability Pricing Model (RPM) Capacity Market, 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] PJM introduced the RPM Capacity Market effective June 1, 2007.

Volume I of the *2007 State of the Market Report* is the Introduction. More detailed analysis and results are included in Volume II.[3]

Conclusions

This report assesses the competitiveness of the markets managed by PJM during 2007, 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 2007:

- 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.

1 See the *2007 State of the Market Report*, Volume II, Appendix A, "PJM Geography" for maps showing the PJM footprint and its evolution.

2 See also the *2007 State of the Market Report,* Volume II, Appendix B, "PJM Market Milestones."

3 Analysis of 2007 market results requires comparison to 2006 and to certain prior years. During calendar years 2004 and 2005, PJM conducted the phased integration of five control zones: ComEd, American Electric Power (AEP), The Dayton Power & Light Company (DAY), Duquesne Light Company (DLCO) and Dominion. By convention, control zones bear the name of a large utility service provider working within their boundaries. The nomenclature applies to the geographic area, not to any single company. For additional information on the integrations, their timing and their impact on the footprint of the PJM service territory, see the *2007 State of the Market Report*, Volume II, Appendix A, "PJM Geography."

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 applies the three pivotal supplier test to determine whether local energy markets are structurally competitive. 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. The test is a flexible, targeted real-time measure of market structure which replaced the previous mitigation method of offer capping of all units required to relieve a constraint. The application of the three pivotal supplier test successfully limits offer capping in the Energy Market to situations where the local market is structurally noncompetitive and where specific owners have structural market power, except in cases where either specific units or interfaces are exempt from the application of this rule.

- 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 enforced and any proposed PJM market rule change should be evaluated for its impact on competitive outcomes.

- Retention and application of the rules included in PJM's 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 limit market power by the application of clear and explicit market power mitigation rules. Implementation of enhancements to incentives for capacity resource performance to ensure stronger, market-based incentives for actual performance when needed.

  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 and extreme inelasticity of demand. The RPM Capacity Market design explicitly allows competitive prices to reflect local scarcity without relying on the exercise of market power to achieve the objectives of the Capacity Market design and explicitly limits the exercise of market power via the application of the three pivotal supplier test.

- Implementation of enhancements to PJM's rules governing operating reserve credits to generators.

  The operating reserve rules should ensure that credits and corresponding charges to market participants are consistent with incentives for efficient market outcomes and should reduce gaming incentives. PJM is expected to file proposed changes, approved by the membership, to the operating reserve rules with the FERC in 2008.

- Continued enhancements to the cost-benefit analysis of congestion and transmission investments to relieve 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. New transmission projects and the lack of existing transmission can have significant impacts on the PJM markets. The goal of transmission planning should ultimately be the incorporation of transmission investment decisions into market-driven processes as much as is practicable.

- Modification of rules governing demand-side programs to ensure appropriate levels of payment and to ensure appropriate measurement and verification of demand-side response. Evaluation of additional actions to address institutional issues which may inhibit the evolution of demand-side price response.

  PJM and the MMU should continue efforts to ensure that market power is not exercised on the demand side of the market, particularly via gaming of the measurement and verification process. The rules governing measurement and verification need to be tightened substantially. The principal barriers to the further development of demand-side response are in the interface between wholesale and retail markets.

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

  PJM and other control area operators have 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 as well as permit market-based congestion management across the Eastern Interconnection. 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. PJM has taken some actions to address this issue and should give a high priority to continued actions to achieve this.

- Continued enhancement of mechanisms used to manage flows at the interfaces between PJM and surrounding areas.

  Changes in net interchange affect PJM operations and markets as they require increases or decreases in generation to meet load. As a result of the fact that ramp is free but is a valuable resource, there are strong incentives to game the ramp rules. The same is true of spot import service.

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

  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 market efficiency and stimulating competition.

- Based on the outcome of the active, public process that addressed the independence of market monitoring during the MMU's ninth year, the MMU is confident that the market monitoring function will be independent, well-organized, well-defined, clear to market participants and consistent with the policies of the FERC.[4, 5]

New Action

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

  The MMU reviewed the summer of 2007 for scarcity conditions and the market prices that resulted. Based on the results, the MMU recommends that PJM's scarcity pricing mechanism be reviewed and modified. The definition of scarcity should include several stages of scarcity, each with an associated administrative 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 that are consistent with economic dispatch, consistent with locational pricing and consistent with competitive market outcomes. PJM should also consider adding new scarcity pricing regions.

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

  The MMU concludes from the analysis of the 2007 data that the PJM Regulation Market in 2007 was characterized by structural market power in 80 percent of the hours, based on the results of the three pivotal supplier test. 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, adjusted to reflect the modified cost definitions implemented in 2007, indicates that offers above the competitive level set the clearing prices in 26 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 PJM Mid-Atlantic 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

4 PJM. "Open Access Transmission Tariff (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 On December 19, 2007, the parties filed a settlement with the Federal Energy Regulatory Commission, pursuant to the September 20, 2007, order in Docket Nos. EL07-56-000 and EL07-58-000 (consolidated).

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 nondiscriminatory basis for all units operating for all constraints. It would be reasonable to implement this change at the same time as the recommended changes to the scarcity pricing rules.

- Consistent application of local market power rules to all units, including those currently exempt from offer capping.

  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."[6] 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."[7] A small number of exempt units accounted for a disproportionate share of markup in 2007. Eight exempt units accounted for 20 percent of the overall markup component of PJM prices in 2007.

  The rationale for grandfathering the specific 56 exempt units was that their owners might have relied on the exemption in deciding whether to invest. Given the substantial changes in PJM markets, including the introduction of the RPM Capacity Market and scarcity pricing, the rationale for grandfathering no longer holds. The combination of RPM and scarcity pricing has had a substantial impact on unit revenues, as demonstrated in the "Net Revenue" section of the *2007 State of the Market Report.* Rather than devise a special market power test for exempt units or go through a separate process for each such unit, it would be reasonable to remove the exemption on a going forward basis.

6 110 FERC ¶ 61,053 (2005).

7 110 FERC ¶ 61,053 (2005).

SECTION 2 – ENERGY MARKET, PART 1

The PJM Energy Market comprises all types of energy transactions, including the sale or purchase of energy in PJM's Day-Ahead and Real-Time Energy Markets, bilateral and forward markets and self-supply. Energy transactions analyzed in this report include those in the PJM Day-Ahead and Real-Time Energy Markets. These markets provide key benchmarks against which market participants may measure results of transactions in other markets.

The PJM Market Monitoring Unit (MMU) analyzed measures of market structure, participant conduct and market performance for 2007, including market size, concentration, residual supply index, price-cost markup, net revenue and price.[1] The MMU concludes that the PJM Energy Market results were competitive in 2007.

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.[2] 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.

Overview

Market Structure

- Supply. During the June to September 2007 summer period, the PJM Energy Market received an hourly average of 154,944 MW in net supply including hydroelectric generation.[3] The summer 2007 net supply was 615 MW lower than the summer 2006 net supply of 155,559. The decrease was comprised of 377 MWh of decreased hydroelectric power generation and 237 MWh of reduced offers from non-hydroelectric capacity.[4]

1 The MMU also compared 2007 market results to 2006 and certain other prior years. During calendar years 2004 and 2005, PJM conducted the phased integration of five control zones: ComEd, American Electric Power (AEP), The Dayton Power & Light Company (DAY), Duquesne Light Company (DLCO) and Dominion. By convention, control zones bear the name of a large utility service provider working within their boundaries. The nomenclature applies to the geographic area, not to any single company. For additional information on the control zones, the integrations, their timing and their impact on the footprint of the PJM service territory, see the *2007 State of the Market Report*, Volume II, Appendix A, "PJM Geography."

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

3 Calculated values shown in Section 2, "Energy Market, Part 1," are based on unrounded, underlying data and may differ from calculations based on the rounded values shown in tables.

4 The *2006 State of the Market Report* reported a summer 2006 net capacity of 155,600 MW, which was rounded to the nearest 100 MW.

- **Demand.** The PJM system peak load in 2007 was 139,428 MW in the hour ended 1600 EPT on August 8, 2007, while the PJM peak load in 2006 was 144,644 in the hour ended 1700 on August 2, 2006.[5] The 2007 peak load was 5,216 MW, or 3.6 percent, lower than the 2006 peak load.

- **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 and continued to apply the test in 2007. PJM offer caps units only when the local market structure is noncompetitive. Offer capping is an effective means of addressing local market power. Offer-capping levels have historically been low in PJM. In the Day-Ahead Energy Market offer-capped unit hours fell from 0.4 percent in 2006 to 0.2 percent in 2007. In the Real-Time Energy Market offer-capped unit hours rose from 1.0 percent in 2006 to 1.1 percent in 2007.

- **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 2007. 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 2007, the top four companies accounted for 40 percent of the system's load-weighted, average locational marginal price (LMP).

  In 2007, coal-fired units accounted for 70 percent of marginal units and natural gas-fired units accounted for 24 percent of all marginal units.

5 For the purpose of Volume I and Volume II of the *2007 State of the Market Report*, all hours are presented and all hourly data are analyzed using Eastern Prevailing Time (EPT). See Appendix M, "Glossary," for a definition of EPT and its relationship to Eastern Standard Time (EST) and Eastern Daylight Time (EDT).

Market Conduct

- Price-Cost Markup. The price-cost markup index is a measure of conduct or behavior by the owners of generating units and not a measure of market impact. 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 0.09 with a monthly average maximum of 0.22 in June and a monthly average minimum of 0.03 in January. The overall results support the conclusion that prices in PJM are set, on average, by marginal units operating at or 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 measured by the price-cost markup index. The MMU calculates explicit measures of the impact of marginal unit markups on LMP. The LMP impact is a measure of market power. The price impact of markup must be interpreted carefully. The price impact is not based on a full redispatch of the system, but such a full redispatch is practically impossible as it would require reconsideration of all dispatch decisions and unit commitments. The markup impact includes the maximum impact of the identified markup conduct on a unit-by-unit basis, but the inclusion of negative markup impacts has an offsetting effect. The markup analysis does not distinguish between intervals in which a unit has local market power or has a price impact in an unconstrained interval. The markup analysis is a more general measure of the competitiveness of the Energy Market.

  The markup component of the overall system load-weighted, average LMP was $5.86 per MWh, or 10 percent. The markup was $8.59 per MWh during peak hours and $2.91 per MWh during off-peak hours. The overall results support the conclusion that prices in PJM are set, on average, by marginal units operating at or close to their marginal costs. This is strong evidence of competitive behavior and competitive market performance.

  A substantial portion of the markup, $0.57 per MWh or 10 percent occurred on high-load days during the summer of 2007. 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 $1.34 per MWh, or 23 percent, of the markup for all days. This is a disproportionate share, given that only 44 of 56 exempt units were marginal and that only eight exempt units of the 44 accounted for $1.15, or 86 percent, of this markup component of price. The average markup per exempt unit is about four times higher than for non-exempt units, and the average markup for the top eight exempt units is about 21 times higher than for non-exempt units.

- Load. On average, PJM real-time load increased in 2007 by 2.8 percent over 2006, rising from 79,471 MW to 81,681 MW.

- 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 rose in 2007 over 2006. The system simple average LMP was 16.9 percent higher in 2007 than in 2006, $57.58 per MWh versus $49.27 per MWh. The load-weighted LMP was 15.6 percent higher in 2007 than in 2006, $61.66 per MWh versus $53.35 per MWh. The fuel-cost-adjusted, load-weighted, average LMP was 18.1 percent higher in 2007 than in 2006, $63.00 per MWh compared to $53.35 per MWh. Fuel costs in 2007 contributed to downward pressure on LMP rather than upward pressure.

- Load and Spot Market. Real-time load is served by a combination of self-supply, bilateral market purchases and spot market purchases. From the perspective of a single PJM billing organization that serves load, its load could be supplied by any combination of its own generation, net bilateral market purchases and net spot market purchases. For 2007, 95.9 percent of real-time load was supplied by bilateral contracts, 3.9 percent by spot market purchases and 0.2 percent by self-supply. Compared with 2006, reliance on bilateral contracts increased by 3.1 percentage points; reliance on spot supply decreased by 2.3 percentage points and reliance on self-supply decreased by 0.8 percentage points in 2007.

Demand-Side Response

- Demand-Side Response (DSR). Markets require both a supply side and a demand side to function effectively. PJM wholesale market, demand-side programs should be understood as one relatively small part of a transition to a fully functional demand side for its Energy Market. A fully developed demand side will include retail programs and an active, well-articulated interaction between wholesale and retail markets. There are significant issues with the current approach to measuring demand-side response MW, which is the basis on which program participants are paid. The current approach can lead to payments when the customer has taken no action to respond to market prices. A substantial improvement in measurement and verification methods must be implemented in order to ensure the credibility of PJM demand-side programs. Total demand-side response resources available in PJM on August 8, 2007 (the peak day in 2007), were 2,145.30 capacity MW and 9.25 energy MW from the Emergency Load-Response Program and 2,498.03 energy MW from the Economic Load-Response Program.

Conclusion

The MMU analyzed key elements of PJM Energy Market structure, participant conduct and market performance for calendar year 2007, 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 decreased by about 600 MW when comparing the summer of 2007 to the summer of 2006 while aggregate peak load decreased by 5,216 MW, modifying the general supply-demand balance from 2006 with a corresponding impact on-peak Energy Market prices. Overall load was higher than in

2006 and there were twice as many high-load days, with a corresponding impact on overall average prices. Market concentration levels remained moderate and average markups remained relatively low although markups increased. 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. The Energy Market was tighter than in 2006 and this explains, at least in part, higher prices and higher markups in 2007. 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 for individual unit offers. LMP is a broader indicator of the level of competition. While PJM has experienced price spikes, these have been limited in duration and, in general, prices in PJM have been well below the marginal cost of the highest cost unit installed on the system. The significant price spikes in PJM have been directly related to scarcity conditions. In PJM, prices tend to increase as the market approaches scarcity conditions as a result of generator offers and the associated shape of the aggregate supply curve. The pattern of prices within days and across months and years illustrates how prices are directly related to demand conditions and thus also illustrates the potential significance of price elasticity of demand in affecting price.

The 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. 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 United States Federal Energy Regulatory Commission's (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 result of the introduction of the three pivotal supplier test was to limit offer capping to times when the local market structure was noncompetitive and 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.[6] 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 nondiscriminatory basis for all units operating for all constraints.

The MMU also recommends that the FERC terminate the exemption from offer capping currently applicable to exempt units. 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 had 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] Exempt units exercised market power in 2006 and in 2007.

The rationale for grandfathering the specific 56 exempt units was that their owners might have relied on the exemption in deciding whether to invest. Given the substantial changes in PJM markets, including the introduction of the Reliability Pricing Model (RPM) construct and scarcity pricing, the rationale for grandfathering no longer holds. The combination of RPM and scarcity pricing has had a substantial impact on unit revenues, as demonstrated in the "Net Revenue" section of the *2007 State of the Market Report*. Rather than devise a special market power test for exempt units or go through a separate process for each such unit, it would be reasonable to remove the exemption on a going forward basis.

Energy Market results, including prices, for 2007 generally reflected supply-demand fundamentals. Higher nominal and load-weighted prices are consistent with a competitive outcome as the higher prices reflect higher overall demand and tighter supply-demand conditions. Fuel costs do not explain the increase in prices in 2007. If fuel costs for the year 2007 had been the same as for 2006, the 2007 load-weighted LMP would have been higher than it was. The overall market results support the conclusion that prices in PJM are set, on average, by marginal units operating at, or close to, their marginal costs. This is 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 2007.

6 See PJM. "Amended and Restated Operating Agreement (OA)," Sections 6.4.1(d)(ii) and 6.4.1(e) (January 19, 2007).

7 110 FERC ¶ 61,053 (2005).

8 110 FERC ¶ 61,053 (2005).

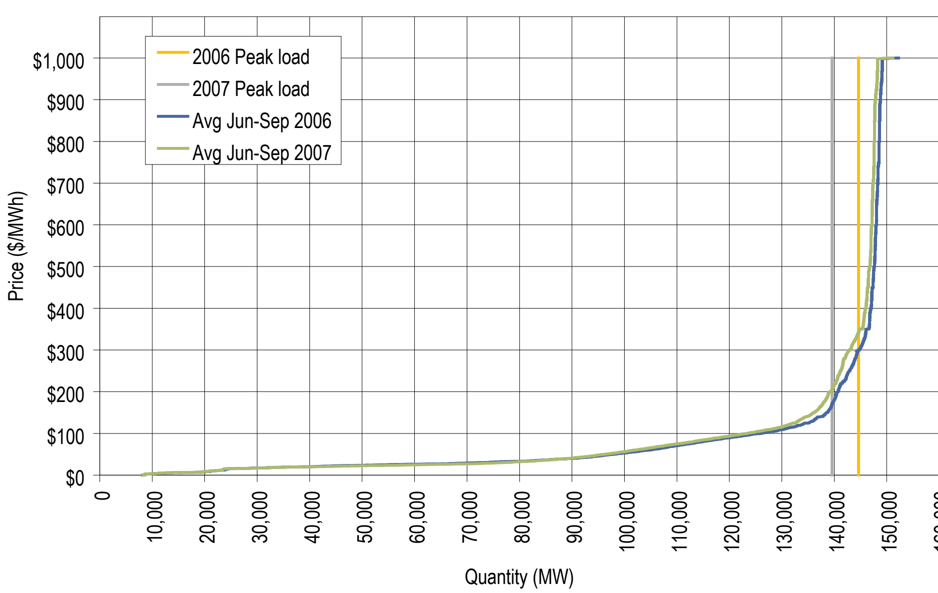
Market Structure

Supply

During the June to September 2007 summer period, the PJM Energy Market received an hourly average of 154,944 MW in net supply including hydroelectric generation. The summer 2007 net supply was 615 MW lower than the summer 2006 net supply of 155,559. The decrease was comprised of 377 MWh of decreased hydroelectric power generation and 237 MWh of reduced offers from non-hydroelectric capacity. During the summer of 2007, the peak demand was 5,216 MW, or 3.6 percent, lower than the 2006 peak and therefore intersected the supply curve at a lower price level. (See Figure 2-1.)

Offer prices on the 2007 supply curve are higher than on the 2006 supply curve from total supply levels of about 90,000 MW to 140,000 MW, corresponding to 2007 offers from about $41 per MWh to about $217 per MWh. During 2007, this range of offers consisted primarily of natural gas-fired steam, combined-cycle (CC) and efficient combustion turbine (CT) units. Approximately 78 percent of all gas-fired generation fell in this portion of the offer curve. The increase in the offer curve was in part the result of higher natural gas prices for summer 2007 compared to summer 2006. The average price of natural gas increased from $6.75 per MBtu for summer 2006 to $7.08 per MBtu for summer 2007, or 4.9 percent. Between about 145,000 MW and 150,000 MW the 2007 supply curve shifted left and parallel to the 2006 supply curve, meaning that incremental offers and MW are comparable between the two years. In aggregate, however, the 2007 supply curve shifted to the left by 895 MW. This shift was the result of a decrease of approximately 280 MW in offers of $500 per MWh to $1,000 per MWh and the 615 MW of decreased net supply. Total 2007 offers in the $500 to $1,000 per MWh range were approximately 7,380 MW.

Figure 2-1 Average PJM aggregate supply curves: Summers 2006 and 2007



During the 12 months ended September 30, 2007, 135 MW of generation entered service in the RTO.[9] The additions consisted of 128 MW in upgrades to existing generation and 7 MW in new generation, of which 5 MW were wind generation and 2 MW were diesel generation. Upgrades to existing facilities included 2 MW of combustion turbine generation, 5 MW of combined-cycle generation, 2 MW of coal-fired steam, 73 MW of gas/oil-fired steam, 13 MW of nuclear steam, 5 MW of wind generation, 25 MW of diesel generation and 3 MW of hydroelectric generation. After accounting for offsetting decreases of 356 MW from the derating of 66 MW of generation, 2 MW removed from RTO dispatch to behind the meter service and the retirement of 288 MW, the net decrease in capacity was 221 MW.

Of the 66 MW of derated generation, 22 MW were combustion turbine generation, 6 MW coal-fired steam, 10 MW gas/oil-fired steam, 4 MW nuclear steam, 8 MW wind generation and 16 MW diesel generation. The 2 MW of generation removed from PJM dispatch were diesel generation. Of the 288 MW of retirements, 280 MW were coal-fired steam, and 8 MW were diesel generation.

The net result of generation additions and subtractions, holding other factors constant, was a slight shift to the left of the PJM aggregate supply curve as a high proportion (97 percent) of retired generation was coal-fired steam generation. The shape of the aggregate supply curve changed only slightly since the net decrease of generation was less than 0.5 percent of the system supply.

Table 2-1 shows the PJM units that retired from October 1, 2006, to September 30, 2007.[10]

Table 2-1 Retired units: October 1, 2006, to September 30, 2007

Unit Name	Installed Capacity (MW)	Unit Type	Retire Date
PECO Delaware Diesel	3	Diesel	10/24/06
PPL Martins Creek 1	140	Steam	9/15/07
PPL Martins Creek 2	140	Steam	9/15/07
PPL Martins Creek D1-D2	5	Diesel	9/15/07
Total	288		

Demand

Table 2-2 shows the actual coincident summer peak loads for the years 1999 through 2007.[11] The 2007 actual summer peak load of 139,428 MW was 5,216 MW less than the 2006 summer peak load of 144,644.

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

10 Retired unit parameters obtained from PJM.

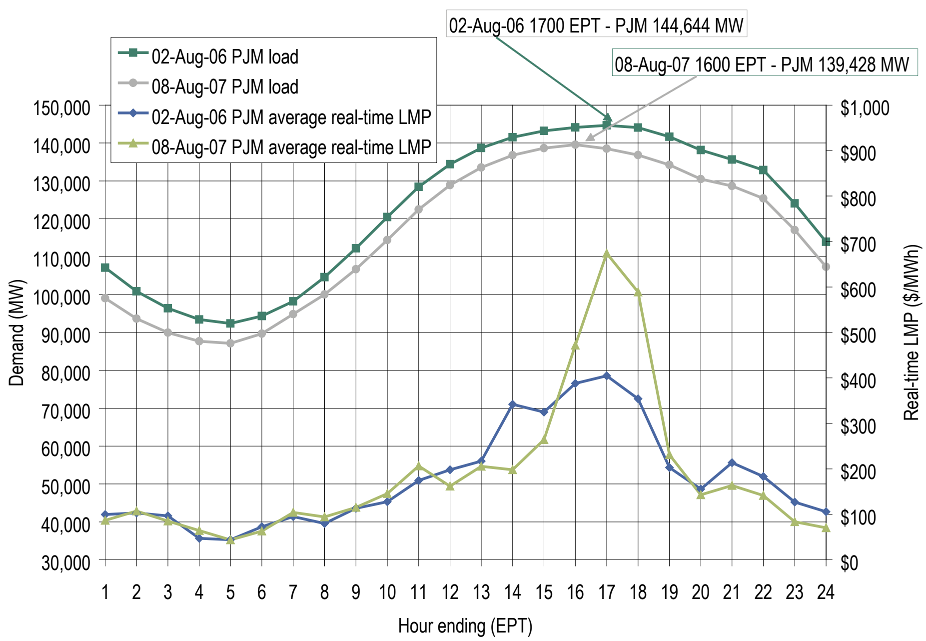
11 Peak loads shown are eMTR load. See the *2007 State of the Market Report*, Volume II, Appendix I, “Load Definitions,” for detailed definitions of load.

Table 2-2 Actual PJM footprint summer peak loads: 1999 to 2007

Year	Date	Hour Ending (EPT)	PJM Load (MW)	Difference (MW)
1999	06-Jul-99	1400	59,365	NA
2000	26-Jun-00	1600	56,727	(2,638)
2001	09-Aug-01	1500	54,015	(2,712)
2002	14-Aug-02	1600	63,762	9,747
2003	22-Aug-03	1600	61,500	(2,262)
2004	03-Aug-04	1700	77,887	16,387
2005	26-Jul-05	1600	133,763	55,876
2006	02-Aug-06	1700	144,644	10,881
2007	08-Aug-07	1600	139,428	(5,216)

The hourly load and average PJM LMP for the 2007 and 2006 summer peak days are shown in Figure 2-2.

Figure 2-2 PJM summer peak-load comparison: Wednesday, August 2, 2006, and Wednesday, August 8, 2007



Market Concentration

During 2007, concentration in the PJM Energy Market was moderate overall. Analyses of supply curve segments indicate moderate concentration in the baseload segment, but high concentration in the intermediate and peaking segments.[12] High concentration levels, particularly in the peaking segment,

12 For the market concentration analysis, supply curve segments are based on a classification of units that generally participate in the PJM Energy Market at varying load levels. Unit class is a primary factor for each classification; however, each unit may have different characteristics that influence the exact segment for which it is classified.

increase the probability that a generation owner will be pivotal during high demand periods. When transmission constraints exist, local markets are created with ownership that is typically significantly more concentrated than the overall Energy Market. PJM offer-capping rules that limit the exercise of local market power and generation owners' obligations to serve load were effective in most cases in preventing the exercise of market power in these areas during 2007. If those obligations were to change or the rules were to change, however, the market-power-related incentives and impacts would change as a result. In addition, units that are exempt from PJM's offer-capping rules did exercise market power in some local markets in 2007.

Concentration ratios are a summary measure of market share, a key element of market structure. High concentration ratios indicate that comparatively small numbers of sellers dominate a market; low concentration ratios mean larger numbers of sellers split market sales more equally. The best tests of market competitiveness are direct tests of the conduct of individual participants and their impact on price. The price-cost markup index is one such test and direct examination of offer behavior by individual market participants is another. Low aggregate market concentration ratios establish neither that a market is competitive nor that participants are unable to exercise market power. High concentration ratios do, however, indicate an increased potential for participants to exercise market power.

Despite their significant limitations, concentration ratios provide useful information on market structure. The concentration ratio used here is the Herfindahl-Hirschman Index (HHI), calculated by summing the squares of the market shares of all firms in a market. Hourly PJM Energy Market HHIs were calculated based on the real-time energy output of generators, adjusted for hourly net imports by owner. (See Table 2-3.)

Actual net imports and import capability were incorporated in the hourly Energy Market HHI calculations because imports are a source of competition for generation located in PJM. Energy can be imported into PJM under most conditions. The hourly HHI was calculated by combining all export and import transactions from each market participant with its generation output from each hour. A market participant's market share increases with imports and decreases with exports.

Hourly HHIs were also calculated for baseload, intermediate and peaking segments of generation supply. Hourly Energy Market HHIs by supply curve segment were calculated based on hourly Energy Market shares, unadjusted for imports.

The "Merger Policy Statement" of the FERC states that a market can be broadly characterized as:

- Unconcentrated. Market HHI below 1000, equivalent to 10 firms with equal market shares;

- Moderately Concentrated. Market HHI between 1000 and 1800; and

- Highly Concentrated. Market HHI greater than 1800, equivalent to between five and six firms with equal market shares.[13]

13 77 FERC ¶ 61,263 (2006), "Inquiry Concerning the Commission's Merger Policy under the Federal Power Act: Policy Statement," Order No. 592, pp. 64-70.

PJM HHI Results

Calculations for hourly HHI indicate that by the FERC standards, the PJM Energy Market during 2007 was moderately concentrated. (See Table 2-3.) Based on the hourly Energy Market measure, average HHI was 1205 with a minimum of 879 and a maximum of 1545 in 2007. The highest hourly market share was 29 percent and the highest average market share for 2007 was 21 percent.

Table 2-3 PJM hourly Energy Market HHI: Calendar year 2007

	Hourly Market HHI
Average	1205
Minimum	879
Maximum	1545
Highest market share (One hour)	29%
Highest market share (All hours)	21%
# Hours	8760
# Hours HHI > 1800	0
% Hours HHI > 1800	0%

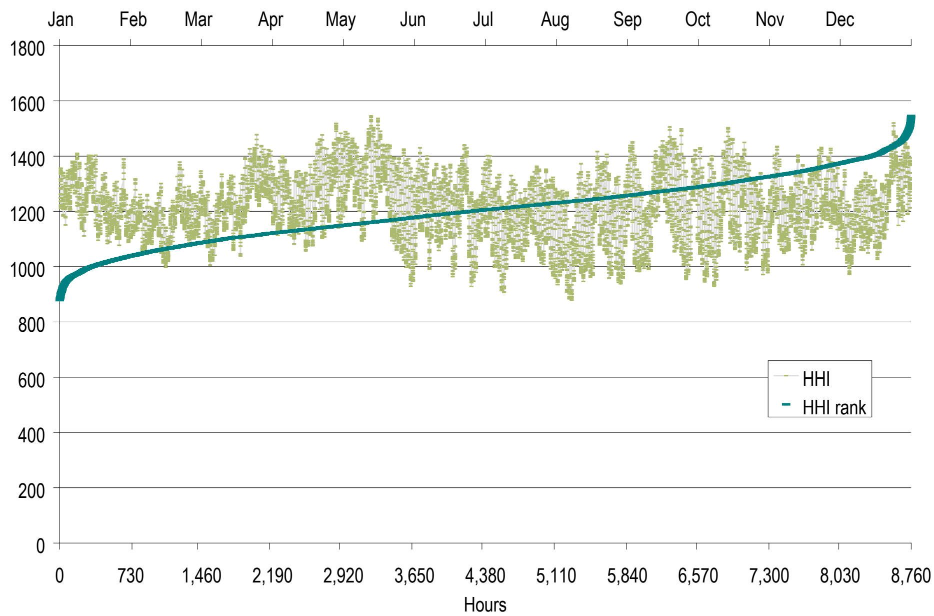
Table 2-4 includes 2007 HHI values by supply curve segment, including base, intermediate and peaking plants. The hourly measure indicates that, on average, intermediate and peaking segments of the supply curve are highly concentrated, while the baseload segment is moderately concentrated.

Table 2-4 PJM hourly Energy Market HHI (By segment): Calendar year 2007

	Minimum	Average	Maximum
Base	1239	1392	1603
Intermediate	664	2158	6365
Peak	596	3746	10000

Figure 2-3 presents the 2007 hourly HHI values in chronological order and an HHI duration curve that shows 2007 HHI values in ascending order of magnitude. The HHI values were in the unconcentrated range for 4 percent of the hours while HHI values were in the moderately concentrated range in the remaining 96 percent of hours, with a maximum value of 1545, as shown in Table 2-3.

Figure 2-3 PJM hourly Energy Market HHI: Calendar year 2007



Local Market Structure and Offer Capping

In the PJM Energy Market, offer capping occurs only as a result of structurally noncompetitive local markets and noncompetitive offers in the Day-Ahead and Real-Time Energy Markets. There are no explicit rules governing market structure or the exercise of market power in the aggregate Energy Market. PJM's market power mitigation goals have focused on market designs that promote competition and that limit market power mitigation to situations where market structure is not competitive and thus where market design alone cannot mitigate market power.

PJM has clear rules limiting the exercise of local market power.[14] The rules provide for offer capping when conditions on the transmission system create a structurally noncompetitive local market (as measured by the three pivotal supplier test), when units in that local market have made noncompetitive offers and when such offers would set the price above the competitive level in the absence of mitigation. Offer caps are set at the level of a competitive offer. Offer-capped units receive the higher of the market price or their offer cap. Thus, if broader market conditions lead to a price greater than the offer cap, the unit receives the higher market price. The rules governing the exercise of local market power recognize that units in certain areas of

14 See PJM. "Amended and Restated Operating Agreement (OA)," Schedule 1, Section 6.4.2. (January 19, 2007).

the system would be in a position to extract monopoly profits, but for these rules. The offer-capping rules exempt certain units from offer capping based on the date of their construction. Such exempt units can, and do, exercise market power, at times, that would not be permitted if the units were not exempt.

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

PJM's three pivotal supplier test represents the practical application of the FERC market power tests in real time.[15] The three pivotal supplier test is passed if no three generation suppliers in a load pocket are jointly pivotal. Stated another way, if the incremental output of the three largest suppliers in a load pocket is removed and enough incremental generation remains available to solve the incremental demand for constraint relief, where the relevant competitive supply includes all incremental MW at a cost less than, or equal, to 1.5 times the clearing price, then offer capping is suspended.

Levels of offer capping have historically been low in PJM, as shown in Table 2-5.

Table 2-5 Annual offer-capping statistics: Calendar years 2003 to 2007

	Real Time		Day Ahead	
	Unit Hours Capped	MW Capped	Unit Hours Capped	MW Capped
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%
2007	1.1%	0.2%	0.2%	0.0%

Table 2-6 presents data on the frequency with which units were offer capped in 2007. Table 2-6 shows the number of generating units that met the specified criteria for total offer-capped run hours and percentage of total run hours that were offer-capped for 2007.[16] For example, in 2007, 15 units were offer-capped for greater than, or equal to, 80 percent and less than 90 percent of their run hours and had 500 or more offer-capped run hours.

15 See the *2007 State of the Market Report*, Volume II, Appendix L, "Three Pivotal Supplier Test."

16 Offer-capped statistics in Table 2-6 are presented in a different format than previous years. The offer-capped percentage categories were also changed slightly to be consistent with the criteria for FMU eligibility. For example, the greater than 60 percent category was changed to greater than, or equal to, 60 percent which is consistent with the criteria for the Tier 1 adder (greater than, or equal to, 60 percent and less than 70 percent). Offer-capped statistics for prior years are shown in the revised format and with the revised percentage categories in the *2007 State of the Market Report,* Volume II, Appendix C, "Energy Market." Data quality improvements have caused values in these tables to vary slightly from previously published results.

Table 2-6 Offer-capped unit statistics: Calendar year 2007

	2007 Offer-Capped Hours					
Run Hours Offer-Capped, Percent Greater Than Or Equal To:	Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
90%	2	1	3	2	6	0
80% and < 90%	15	3	0	14	13	6
75% and < 80%	0	0	0	0	2	4
70% and < 75%	0	0	2	0	1	3
60% and < 70%	0	0	0	1	3	24
50% and < 60%	1	0	0	0	0	21
25% and < 50%	0	0	0	0	0	51
10% and < 25%	0	0	0	3	12	37

Table 2-6 shows that a small number of units are offer capped for a significant number of hours or for a significant proportion of their run hours. For example, only 47 units (about 4 percent of all units) that had offer-capped run hours of at least 200 hours (about 2 percent of all hours) in 2007 were offer capped for 10 percent or more of their run hours. Only 22 units (or about 2 percent of all units) had greater than, or equal to, 400 offer-capped run hours.

When compared to the 2006 offer-capped statistics, 25 percent of the categories show an increase in the number of units; 29 percent of the categories show no change and 46 percent of the categories show a decrease in the number of units.[17]

When compared to the 2005 offer-capped statistics, 31 percent of the categories show an increase in the number of units; 21 percent of the categories show no change and 48 percent of the categories show a decrease in the number of units.[18]

Units that are offer capped for greater than, or equal to, 60 percent of their run hours are designated as frequently mitigated units (FMUs). An FMU or units that are associated with the FMU (AUs) are entitled to include adders in their cost-based offers that are a form of local scarcity pricing.

Local Market Structure

In 2007, the PSEG, AP, AEP, Met-Ed, JCPL, PENELEC, Dominion, DPL, AECO and DLCO control zones experienced congestion resulting from one or more constraints binding for 100 or more hours. Using the three pivotal supplier results for calendar year 2007, actual competitive conditions associated with each of these frequently binding constraints were analyzed in real time.[19] The ComEd, BGE, PECO, PPL, RECO, Pepco and DAY control zones were not affected by constraints binding for 100 or more hours.

17 See the *2007 State of the Market Report*, Volume II, Appendix C, "Energy Market" Table C-22 for 2006 data.

18 See the *2007 State of the Market Report*, Volume II, Appendix C, "Energy Market" Table C-21 for 2005 data.

19 See the *2007 State of the Market Report*, Volume II, Appendix L, "Three Pivotal Supplier Test" for a more detailed explanation of the three pivotal supplier test.

The three pivotal supplier test is applied by PJM on an ongoing basis in order to determine whether offer capping is required to prevent the exercise of local market power for any constraint not exempt from offer capping. The MMU analyzed the results of the three pivotal supplier tests conducted by PJM for the Real-Time Energy Market for the period January 1, 2007, through December 31, 2007.

Overall, the results confirm that the three pivotal supplier test results in offer capping when the local market is structurally noncompetitive and does not result in offer capping when that is not the case. Local markets are noncompetitive when there is a small number of suppliers. The number of hours in which one or more suppliers pass the three pivotal supplier test and are exempt from offer capping increases as the number of suppliers in the local market increases. For example, the regional constraints have a larger number of suppliers and more than 59 percent of the three pivotal supplier tests have one or more passing owners. In contrast, more local constraints like Gardners – Hunterstown in the Met-Ed Control Zone have only two suppliers and therefore are always structurally noncompetitive.

The fact that some non-exempt constraints never had any generation resources that failed the three pivotal supplier test during the period analyzed does not lead to the conclusion that such constraints should always be exempt from offer capping for local market power. The same logic applies to currently exempt interface constraints. Even if no generation resources associated with any of the exempt interface constraints failed the three pivotal suppler test during the period analyzed, that does not mean that such interfaces should always be exempt from offer capping for local market power. The fact that one or more generation resources, required to resolve these interfaces, did fail the three pivotal supplier test at times simply reinforces the point. If the generation resources associated with these interfaces always pass the three pivotal supplier test, there will be no offer capping; and conversely if such resources at times fail the three pivotal supplier test, appropriate offer capping will be applied.

The MMU also recommends that three pivotal supplier testing be applied to all constraints in the clearing of the PJM Day-Ahead Energy Market. While PJM applies three pivotal supplier testing to the exempt interfaces in real time, the test is not applied consistently to the exempt interfaces in the Day-Ahead Market and the results of the test are not saved. As a result, it is not possible to analyze the market structure associated with the exempt interfaces in the Day-Ahead Market. The currently exempt interfaces accounted for $167.6 million in day-ahead and -$5.3 million in balancing congestion costs during 2007. The exempt interfaces were constrained for more hours in the Day-Ahead Market than in the Real-Time Market. During 2007, the exempt interfaces were constrained 2,703 hours in the Day-Ahead Market and 501 hours in the Real-Time Market.

Information is provided for each constraint including the number of tests applied and the number of tests in which one or more owners passed and/or failed the three pivotal supplier test.[20] Additional information is provided for each constraint including the average MW required to relieve a constraint, the average supply available, the average number of owners included in each test and the average number of owners that passed or failed each test.

- Regional 500 kV Constraints. In 2007, several regional transmission constraints occurred for more than 100 hours. The Kammer 765/500 kV transformer, along with four interface constraints (5004/5005,

20 The three pivotal supplier test in the Real-Time Energy Market is applied by PJM as necessary and may be applied multiple times within a single hour for a specific constraint. Each application of the test is done in a five-minute interval.

AP South, Bedington – Black Oak and West) all experienced more than 100 hours of congestion.[21] The three pivotal supplier test was applied to all of these constraints. The AP South and West interfaces are two of the four interfaces for which generation owners are exempt from offer capping.

Table 2-7 includes information on the three pivotal supplier test results for the regional constraints.[22] For the three regional constraints that are not exempt, the percentage of tested intervals resulting in one or more owners passing ranged from 81 percent to 89 percent while 21 percent to 34 percent of the tests show one or more owners failing. For the AP South and West interfaces, which are exempt from offer capping, the percentage of tested intervals resulting in one or more owners passing ranged from 59 percent to 96 percent while 8 percent to 54 percent of the tests show one or more owners failing.

Table 2-7 Three pivotal supplier results summary for regional constraints: Calendar year 2007

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
5004/5005 Interface	Peak	646	576	89%	147	23%
	Off peak	274	228	83%	84	31%
AP South	Peak	276	176	64%	140	51%
	Off peak	157	92	59%	85	54%
Bedington - Black Oak	Peak	3,184	2,577	81%	1,071	34%
	Off peak	5,000	4,291	86%	1,405	28%
Kammer	Peak	1,487	1,327	89%	318	21%
	Off peak	2,518	2,114	84%	746	30%
West	Peak	718	689	96%	59	8%
	Off peak	656	618	94%	58	9%

Table 2-8 shows that, on average, during 2007 peak periods, the local markets created by the 5004/5005 Interface and the Kammer transformer had 21 owners with available supply and 20 owners with available supply, respectively. Of those owners, an average of 18 passed the test for the 5004/5005 Interface and an average of 17 passed the test for the Kammer transformer.[23] Bedington – Black Oak, on average, had 13 owners with available supply and 10 owners passed the test. For AP South, on average, 10 out of 17 owners passed the test during both on-peak and off-peak periods. For the West Interface, on average, 19 out of 20 owners passed the test during on-peak periods, and 17 out of 18 owners passed the test during off-peak periods.

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

22 The number of tests with one or more failing owners plus the number of tests with one or more passing owners can exceed the total number of tests applied. A single test can result in one or more owners passing and one or more owners failing. In such a case, the interval would be counted as including one or more passing owners and one or more failing owners.

23 The average number of owners passing and the average number of owners failing are rounded to the nearest whole number and may not sum to the average number of owners, also rounded to the nearest whole number.

Table 2-8 Three pivotal supplier test details for regional constraints: Calendar year 2007

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
5004/5005 Interface	Peak	109	424	21	18	3
	Off peak	96	356	17	14	3
AP South	Peak	96	306	17	10	7
	Off peak	91	301	17	10	7
Bedington - Black Oak	Peak	62	234	13	10	3
	Off peak	63	240	11	9	2
Kammer	Peak	87	377	20	17	3
	Off peak	72	307	16	12	3
West	Peak	158	758	20	19	1
	Off peak	146	716	18	17	1

- East Interface and Central Interface. The remaining two exempt interfaces, the East and Central interface constraints occurred for fewer than 100 hours. The East Interface constraint occurred for five hours in 2007, while the Central Interface constraint occurred for 25 hours in 2007. Table 2-9 shows that the percentage of tested intervals resulting in one or more owners passing ranged from 56 percent to 97 percent while 14 percent to 100 percent of the tests showed one or more owners failing.

Table 2-9 Three pivotal supplier results summary for the East and Central interfaces: Calendar year 2007

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
Central	Peak	28	24	86%	5	18%
	Off peak	29	28	97%	4	14%
East	Peak	9	5	56%	7	78%
	Off peak	1	0	0%	1	100%

Table 2-10 shows that, on average, the local market created by the East Interface had 15 owners during peak periods and seven passed the test. No owners passed the test during off-peak periods in 2007. The local market created by the Central Interface had 19 owners during off-peak periods and all passed the test. During on-peak periods, 17 of 19 passed the test for the Central Interface.

Table 2-10 Three pivotal supplier test details for the East and Central interfaces: Calendar year 2007

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Central	Peak	87	445	19	17	3
	Off peak	168	914	19	19	1
East	Peak	363	1,009	15	7	8
	Off peak	187	694	12	0	12

- PSEG Control Zone Constraints. In 2007, five constraints in the PSEG Control Zone occurred for more than 100 hours. Table 2-11 and Table 2-12 show the results of the three pivotal supplier tests applied to these constraints. For four of the five constraints, the average number of owners with available supply was four or less. The three pivotal supplier test results reflect this, as the average number of owners that passed is significant only for the Cedar Grove – Roseland 230 kV line, which had more than four owners, on average. The Cedar Grove – Roseland 230 kV line had more owners and more effective supply and thus a higher percentage of tests with one or more owners that passed the three pivotal supplier test.

Table 2-11 Three pivotal supplier results summary for constraints located in the PSEG Control Zone: Calendar year 2007

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
Branchburg - Flagtown	Peak	227	0	0%	227	100%
	Off peak	90	0	0%	90	100%
Branchburg - Readington	Peak	1,780	119	7%	1,760	99%
	Off peak	689	27	4%	683	99%
Brunswick - Edison	Peak	164	0	0%	164	100%
	Off peak	84	0	0%	84	100%
Cedar Grove - Roseland	Peak	148	26	18%	132	89%
	Off peak	210	28	13%	198	94%
Edison - Meadow Rd	Peak	270	0	0%	270	100%
	Off peak	34	0	0%	34	100%

Table 2-12 Three pivotal supplier test details for constraints located in the PSEG Control Zone: Calendar year 2007

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Branchburg - Flagtown	Peak	23	21	3	0	3
	Off peak	26	4	3	0	3
Branchburg - Readington	Peak	27	64	4	0	3
	Off peak	23	68	4	0	4
Brunswick - Edison	Peak	11	84	1	0	1
	Off peak	10	76	1	0	1
Cedar Grove - Roseland	Peak	51	124	8	1	7
	Off peak	50	140	9	1	8
Edison - Meadow Rd	Peak	7	37	1	0	1
	Off peak	5	25	1	0	1

- **AP Control Zone Constraints.** In 2007, there were nine constraints that occurred for more than 100 hours in the AP Control Zone. Table 2-13 and Table 2-14 show the results of the three pivotal supplier tests applied to the constraints in the AP Control Zone. For six of the nine constraints, the average number of owners with available supply was six or less. The three pivotal supplier test results reflect this, as the average number of owners that passed is significant only for the three constraints with a larger number of owners, on average. Three constraints, the Mount Storm – Pruntytown 500 kV line, the Sammis – Wylie Ridge 345 kV line and the Wylie Ridge transformer had more owners and more effective supply and thus a higher percentage of tests with one or more owners that passed.

Table 2-13 Three pivotal supplier results summary for constraints located in the AP Control Zone: Calendar year 2007

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
Bedington	Peak	2,017	4	0%	2,017	100%
	Off peak	548	0	0%	548	100%
Bedington - Nipetown	Peak	603	0	0%	603	100%
	Off peak	153	0	0%	153	100%
Elrama - Mitchell	Peak	975	209	21%	915	94%
	Off peak	1,930	397	21%	1,834	95%
Meadow Brook	Peak	1,974	0	0%	1,974	100%
	Off peak	213	0	0%	213	100%
Mitchell - Shepler Hill	Peak	344	0	0%	344	100%
	Off peak	325	0	0%	325	100%
Mitchell - Union Jct	Peak	265	0	0%	265	100%
	Off peak	113	0	0%	113	100%
Mount Storm - Pruntytown	Peak	168	132	79%	82	49%
	Off peak	481	410	85%	148	31%
Sammis - Wylie Ridge	Peak	39	18	46%	23	59%
	Off peak	394	285	72%	169	43%
Wylie Ridge	Peak	1,283	594	46%	759	59%
	Off peak	1,895	1,436	76%	712	38%

Table 2-14 Three pivotal supplier test details for constraints located in the AP Control Zone: Calendar year 2007

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Bedington	Peak	27	4	2	0	2
	Off peak	29	6	2	0	2
Bedington - Nipetown	Peak	9	5	2	0	2
	Off peak	15	5	2	0	2
Elrama - Mitchell	Peak	27	75	6	1	5
	Off peak	28	50	5	1	5
Meadow Brook	Peak	34	1	2	0	2
	Off peak	20	1	2	0	2
Mitchell - Shepler Hill	Peak	8	10	2	0	2
	Off peak	10	7	2	0	2
Mitchell - Union Jct	Peak	13	47	2	0	2
	Off peak	13	29	2	0	2
Mount Storm - Pruntytown	Peak	127	368	13	9	4
	Off peak	104	379	11	9	2
Sammis - Wylie Ridge	Peak	42	73	15	8	7
	Off peak	43	110	16	10	5
Wylie Ridge	Peak	34	104	11	9	2
	Off peak	50	167	16	12	4

- AEP Control Zone Constraints. In 2007, there were five constraints that occurred for more than 100 hours in the AEP Control Zone. Table 2-15 and Table 2-16 show the results of the three pivotal supplier tests applied to the constraints in the AEP Control Zone. For three of the five constraints, the average number of owners with available supply was two or less. The three pivotal supplier test results reflect this, as the average number of owners that passed is significant only for the two constraints with the largest number of owners, on average. Two constraints, the Cloverdale – Lexington 500 kV line and the Cloverdale transformer, had more owners and more effective supply and thus a higher percentage of tests with one or more owners that passed.

Table 2-15 Three pivotal supplier results summary for constraints located in the AEP Control Zone: Calendar year 2007

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
Amos	Peak	529	0	0%	529	100%
	Off peak	89	0	0%	89	100%
Cloverdale	Peak	122	60	49%	82	67%
	Off peak	460	317	69%	227	49%
Cloverdale - Lexington	Peak	1,955	1,482	76%	874	45%
	Off peak	7,494	5,287	71%	3,819	51%
Darwin - Eugene	Peak	792	0	0%	792	100%
	Off peak	19	0	0%	19	100%
Mahans Lane - Tidd	Peak	340	0	0%	340	100%
	Off peak	474	0	0%	474	100%

Table 2-16 Three pivotal supplier test details for constraints located in the AEP Control Zone: Calendar year 2007

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Amos	Peak	33	19	2	0	2
	Off peak	24	19	2	0	2
Cloverdale	Peak	91	215	12	5	7
	Off peak	74	232	11	7	4
Cloverdale - Lexington	Peak	101	352	17	12	5
	Off peak	97	290	14	9	6
Darwin - Eugene	Peak	30	61	1	0	1
	Off peak	38	74	2	0	2
Mahans Lane - Tidd	Peak	10	16	1	0	1
	Off peak	20	12	1	0	1

- Met-Ed Control Zone Constraints. In 2007, there were four constraints that occurred for more than 100 hours in the Met-Ed Control Zone. Table 2-17 and Table 2-18 show the results of the three pivotal supplier tests applied to the constraints in the Met-Ed Control Zone. For three of the four constraints, the average number of owners with available supply was two or less. The three pivotal supplier test results reflect this, as the average number of owners that passed is significant only for the one constraint with the largest number of owners, on average. The Brunner Island – Yorkana 230 kV line had more owners and more effective supply and thus a higher percentage of tests with one or more owners that passed.

Table 2-17 Three pivotal supplier results summary for constraints located in the Met-Ed Control Zone: Calendar year 2007

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
Brunner Island - Yorkana	Peak	531	277	52%	354	67%
	Off peak	230	105	46%	194	84%
Gardners - Hunterstown	Peak	375	1	0%	375	100%
	Off peak	58	0	0%	58	100%
Hunterstown	Peak	209	0	0%	209	100%
	Off peak	12	0	0%	12	100%
Jackson	Peak	290	0	0%	290	100%
	Off peak	5	0	0%	5	100%

Table 2-18 Three pivotal supplier test details for constraints located in the Met-Ed Control Zone: Calendar year 2007

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Brunner Island - Yorkana	Peak	28	70	12	7	5
	Off peak	32	65	9	5	5
Gardners - Hunterstown	Peak	9	14	2	0	2
	Off peak	9	17	2	0	2
Hunterstown	Peak	10	27	2	0	2
	Off peak	8	41	2	0	2
Jackson	Peak	14	18	2	0	2
	Off peak	7	17	1	0	1

- JCPL Control Zone Constraints. In 2007, the Atlantic — Larrabee 230 kV line was the only constraint in the JCPL Control Zone to occur for more than 100 hours. Table 2-19 and Table 2-20 show the results of the three pivotal supplier tests applied to this constraint. The average number of owners with available supply was five on peak and three off peak. The three pivotal supplier test results reflect this, as 91 percent of the tests applied on peak and 100 percent of the tests applied off peak resulted in one or more owners failing the test.

Table 2-19 Three pivotal supplier results summary for constraints located in the JCPL Control Zone: Calendar year 2007

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
Atlantic - Larrabee	Peak	175	35	20%	160	91%
	Off peak	320	9	3%	320	100%

Table 2-20 Three pivotal supplier test details for constraints located in the JCPL Control Zone: Calendar year 2007

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Atlantic - Larrabee	Peak	32	25	5	1	5
	Off peak	35	36	3	0	3

- PENELEC Control Zone Constraints. In 2007, the East Towanda transformer and the East Towanda – South Troy line were the only constraints to occur for more than 100 hours in the PENELEC Control Zone. Table 2-21 and Table 2-22 show the results of the three pivotal supplier tests applied to the constraints in the PENELEC Control Zone. The average number of owners with available supply was three on peak and three off peak for the East Towanda transformer and one on peak and one off peak for the East Towanda – South Troy line. The three pivotal supplier test results reflect this, as all tests were failed.

Table 2-21 Three pivotal supplier results summary for constraints located in the PENELEC Control Zone: Calendar year 2007

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
East Towanda	Peak	1,813	14	1%	1,806	100%
	Off peak	342	0	0%	342	100%
East Towanda - S.Troy	Peak	3	0	0%	3	100%
	Off peak	19	0	0%	19	100%

Table 2-22 Three pivotal supplier test details for constraints located in the PENELEC Control Zone: Calendar year 2007

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
East Towanda	Peak	12	4	3	0	3
	Off peak	6	4	3	0	3
East Towanda - S.Troy	Peak	4	17	1	0	1
	Off peak	7	3	1	0	1

- Dominion Control Zone Constraints. In 2007, there were three constraints in the Dominion Control Zone that occurred for more than 100 hours. Table 2-23 and Table 2-24 show the results of the three pivotal supplier test applied to the constraints in the Dominion Control Zone. The average number of owners with available supply was one on peak and one off peak for the Beechwood – Kerr Dam and the Halifax – Mount Laurel lines and six on peak and six off peak for the Clover transformer constraint. The three pivotal supplier test results reflect this, as nearly all tests were failed.

Table 2-23 Three pivotal supplier results summary for constraints located in the Dominion Control Zone: Calendar year 2007

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
Beechwood - Kerr Dam	Peak	649	0	0%	649	100%
	Off peak	62	0	0%	62	100%
Clover	Peak	620	149	24%	601	97%
	Off peak	47	12	26%	47	100%
Halifax - Mount Laurel	Peak	584	46	8%	538	92%
	Off peak	384	54	14%	330	86%

Table 2-24 Three pivotal supplier test details for constraints located in the Dominion Control Zone: Calendar year 2007

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Beechwood - Kerr Dam	Peak	6	5	1	0	1
	Off peak	5	4	1	0	1
Clover	Peak	39	110	6	1	5
	Off peak	58	101	6	0	6
Halifax - Mount Laurel	Peak	11	2	1	0	1
	Off peak	11	2	1	0	1

- DPL Control Zone Constraints. In 2007, the Greenbush — Hallwood 69 kV line was the only constraint in the DPL Control Zone to occur for more than 100 hours. Table 2-25 and Table 2-26 show the results of the three pivotal supplier test applied to this constraint. The average number of owners with available supply was one. The three pivotal supplier test results reflect this, as all tests were failed.

Table 2-25 Three pivotal supplier results summary for constraints located in the DPL Control Zone: Calendar year 2007

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
Greenbush - Hallwood	Peak	73	0	0%	73	100%
	Off peak	37	0	0%	37	100%

Table 2-26 Three pivotal supplier test details for constraints located in the DPL Control Zone: Calendar year 2007

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Greenbush - Hallwood	Peak	3	11	1	0	1
	Off peak	3	14	1	0	1

- **AECO Control Zone Constraints.** In 2007, there were two constraints in the AECO Control Zone that occurred for more than 100 hours. Table 2-27 and Table 2-28 show the results of the three pivotal supplier test applied to the constraints in the AECO Control Zone. The average number of owners with available supply was one. The three pivotal supplier test results reflect this, as all tests were failed.

Table 2-27 Three pivotal supplier results summary for constraints located in the AECO Control Zone: Calendar year 2007

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
Beckett - Paulsboro	Peak	885	0	0%	885	100%
	Off peak	277	0	0%	277	100%
Churchtown	Peak	203	0	0%	203	100%
	Off peak	177	0	0%	177	100%

Table 2-28 Three pivotal supplier test details for constraints located in the AECO Control Zone: Calendar year 2007

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Beckett - Paulsboro	Peak	5	5	1	0	1
	Off peak	2	6	1	0	1
Churchtown	Peak	28	22	1	0	1
	Off peak	3	26	1	0	1

- **DLCO Control Zone Constraints.** In 2007, two constraints in the DLCO Control Zone experienced more than 100 hours of congestion. Table 2-29 and Table 2-30 show the results of the three pivotal supplier test applied to the constraints in the DLCO Control Zone. The average number of owners with available supply was one on peak and one off peak for the Cheswick – Evergreen line and two on peak and two off peak for the Collier – Elwyn line. The three pivotal supplier test results reflect this, as nearly all tests were failed.

Table 2-29 Three pivotal supplier results summary for constraints located in the DLCO Control Zone: Calendar year 2007

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
Cheswick - Evergreen	Peak	263	0	0%	263	100%
	Off peak	21	0	0%	21	100%
Collier - Elwyn	Peak	415	1	0%	414	100%
	Off peak	296	0	0%	296	100%

Table 2-30 Three pivotal supplier test details for constraints located in the DLCO Control Zone: Calendar year 2007

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Cheswick - Evergreen	Peak	9	42	1	0	1
	Off peak	10	37	1	0	1
Collier - Elwyn	Peak	29	10	2	0	2
	Off peak	14	19	2	0	2

Characteristics of Marginal Units

Ownership of Marginal Units

Table 2-31 shows the contribution to PJM annual, load-weighted LMP by individual generation owner, utilizing generator sensitivity factors.[24] The contribution of each marginal unit to price at each load bus is calculated for the year and summed by the company that offers the unit into the Energy Market. The results show that, during calendar year 2007, the offers of one company contributed 13 percent of the annual load-weighted, average PJM system LMP and that the offers of the top four companies contributed 40 percent of the annual load-weighted, average PJM system LMP. There were 46 companies with individual contributions less than 4 percent and a combined contribution of 29 percent.

Table 2-31 Marginal unit contribution to PJM annual, load-weighted LMP (By company): Calendar year 2007

Company	Percent of Price
1	13%
2	10%
3	9%
4	8%
5	8%
6	7%
7	7%
8	5%
9	4%
Other (46 companies)	29%

24 See the *2007 State of the Market Report*, Volume II, Appendix K, "Calculation and Use of Generator Sensitivity/Unit Participation Factors."

Marginal Unit Fuel

Table 2-32 shows the type of fuel used by marginal units.[25] In 2007, coal-fired units accounted for 70 percent of marginal units and natural gas-fired units accounted for 24 percent of all marginal units.[26]

Table 2-32 Type of fuel used (By marginal units): Calendar years 2005 to 2007

Fuel Type	2005	2006	2007
Coal	69%	70%	70%
Misc	1%	1%	2%
Natural gas	23%	25%	24%
Nuclear	0%	0%	0%
Petroleum	8%	5%	5%

Market Conduct

Unit Markup

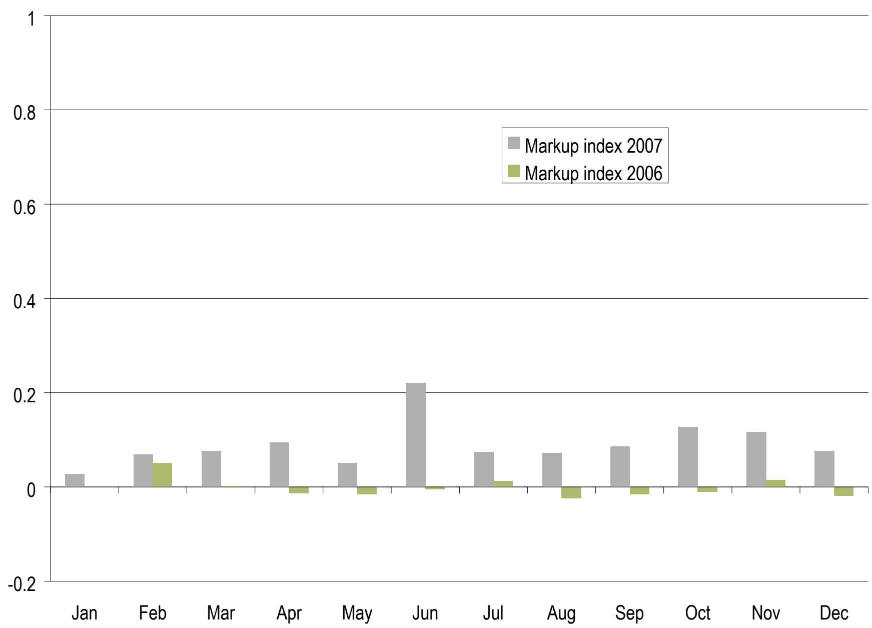
The price-cost markup index is a measure of conduct or behavior by the owners of generating units and not a measure of market impact. For marginal units, the markup index is a measure of market power. For units not on the margin, the markup index is a measure of the intent to exercise market power or, in cases where the markup results in higher-priced units replacing lower-priced units in the dispatch, also a measure of market power. A positive markup by marginal units results in a difference between the observed market price and the competitive market price. The goal of the markup analysis is both to calculate the actual markups by marginal units (market conduct) and to estimate the impact of those markups on the difference between the observed market price and the competitive market price (market impact or market performance). The results must be interpreted carefully, however, because the impact is not based on a full redispatch of the system.

25 These percentages represent the proportion of the five-minute intervals that units of the specified fuel type were marginal compared to the total number of marginal unit intervals. For any interval with multiple marginal units, each unit is credited with an equal share of the interval. This methodology is the same one used to develop the marginal fuel type data posted to the PJM Web site at http://www.pjm.com/markets/jsp/marg-fuel-type-data.jsp. For example, a coal unit is on the margin during the first half of one hour. In the second half of the hour, two units are on the margin: a coal and a natural gas unit. Coal and gas are jointly marginal for the second half-hour. Coal is marginal for six five-minute intervals and jointly marginal for six five-minute intervals. Gas is jointly marginal for six five-minute intervals. Coal has a weight of 1.0 for the first six intervals and coal and gas each have a weight of 0.5 for the second six intervals. In this example, coal would be marginal for 75 percent of the hour and natural gas would be marginal for 25 percent of the hour.

26 The separate impact of each type of fuel on load-weighted, average LMP for 2007 is defined in the *2007 State of the Market Report*, Volume II, Section 2, "Energy Market, Part 1," at "Components of Real-Time, Load-Weighted LMP," Table 2-59, "Components of PJM annual, load-weighted, average LMP."

Figure 2-4 shows the load-weighted, unit markup index. The markup index for each marginal unit is calculated as (Price – Cost)/Price.[27] The markup index is normalized and can vary from -1.00 when the offer price is less than marginal cost, to 1.00 when the offer price is higher than marginal cost.[28] This index calculation method weights the impact of individual unit markups using sensitivity factors.[29] In 2007, the annual average markup index was 0.09 with a maximum of 0.22 in June and a minimum of 0.03 in January. The annual average markup index was higher than in 2006. In 2006, the annual average markup index was 0.00 with a maximum of 0.05 in February and a minimum of -0.02 in August.

Figure 2-4 Load-weighted unit markup index: Calendar years 2006 to 2007



27 A marginal unit's offer price does not always correspond to the LMP at the unit's bus. As a general matter the LMP at a bus is equal to the unit's offer. However in practice, actual, security-constrained dispatch can create conditions where the LMP at a marginal unit bus does not correspond to the unit's offer. The unit offer price and associated cost are used when calculating measures of participant behavior or conduct, like markup.

28 In order to normalize the index results (i.e., bound the results between +1.00 and -1.00), the index is calculated as (Price – Cost)/Price when price is greater than cost, and (Price – Cost)/Cost when price is less than cost.

29 In prior state of the market reports, the impact of each marginal unit on load and LMP was based on an estimate when there were multiple marginal units. Sensitivity factors define the impact of each marginal unit on LMP at every bus on the system. See the *2007 State of the Market Report*, Volume II, Appendix K, "Calculation and Use of Generator Sensitivity/Unit Participation Factors." See also "PJM 101: The Basics" (September 14, 2006) <http://www.pjm.com/services/training/downloads/pjm101part1.pdf> (5.7 MB), p. 107.

Unit Markup Characteristics

In order to contribute to a more complete description of markup behavior, this section includes information on markup by unit and fuel type and by offer price category.

Table 2-33 shows the annual average unit markup for marginal units, by unit type and primary fuel.

Table 2-33 Average marginal unit markup index (By primary fuel and unit type): Calendar year 2007

Fuel Type	Unit Type	Average Markup Index	Average Dollar Markup
Coal	Steam	0.03	$5.44
Heavy oil	Steam	0.01	$1.93
Hydroelectric	Hydroelectric	0.00	$0.00
Light oil	CT	0.10	$39.96
Light oil	Diesel	0.07	$16.48
Misc	Misc	0.01	($1.26)
Natural gas	CC	0.08	$22.37
Natural gas	CT	0.04	$7.06
Natural gas	Diesel	0.04	$9.72
Natural gas	Steam	0.02	$7.37
Nuclear	Steam	(0.00)	$0.23

Table 2-34 shows the average markup of marginal units, by offer price category. A unit is assigned to a price category for each interval in which it was marginal, based on its offer price at that time.

Table 2-34 Average marginal unit markup index (By price category): Calendar year 2007

Price Category	Average Markup Index	Average Dollar Markup
< $25	(0.09)	($2.36)
$25 to $50	(0.02)	($1.43)
$50 to $75	0.06	$0.01
$75 to $100	0.13	$9.50
$100 to $125	0.17	$18.33
$125 to $150	0.19	$25.88
> $150	0.14	$51.01

Market Performance: Markup

The markup index is a summary measure of the behavior or conduct of individual marginal units. However the markup conduct measure does not explicitly capture the impact of this behavior on market prices. As an example, if unit A has a $90 cost and a $100 price, while unit B has a $9 cost and a $10 price, both would show a markup of 10 percent, but the price impact of unit A's markup at the generator bus would be $10 while the price impact of unit B's markup at the generator bus would be $1. Depending on each unit's location on the transmission system, those bus-level impacts could also translate to different impacts on total system price.

The MMU calculates the impact on system prices of marginal unit price-cost markup, based on analysis using sensitivity factors. These measures include the impact of markup on system prices and the impact of markup on zonal prices. In addition, the impact of the markup of specific subsets of units on system and zonal prices is analyzed, including units exempt from offer capping, units on high-load days and frequently mitigated units.

In each case, the calculation shows the markup component of price based on a comparison between the price-based offer and the cost-based offer of each actual marginal unit on the system.[30] The calculation is not based on a full redispatch of the system to determine the marginal units and their marginal costs that would have occurred if all units had made all offers at marginal cost. Thus the results do not reflect a counterfactual market outcome based on the assumption that all units made all offers at marginal cost. It is important to note that a full redispatch analysis is practically impossible and a limited redispatch analysis would not be dispositive. Nonetheless, such a hypothetical counterfactual analysis would reveal the extent to which the actual system dispatch is less than competitive if it showed a difference between dispatch based on marginal cost and actual dispatch. It is possible that the unit-specific markup, based on a redispatch analysis, would be lower than the markup component of price if the reference point were an inframarginal unit with a lower price and a higher cost than the actual marginal unit. If the actual marginal unit has marginal costs that would cause it to be inframarginal, a new unit would be marginal. If the offer of that new unit were greater than the cost of the original marginal unit, the markup impact would be lower than the MMU measure. If the newly marginal unit is on a price-based schedule, the analysis would have to capture the markup impact of that unit as well.

The MMU calculates explicit measures of the impact of marginal unit markups on LMP. The price impact of markup must be interpreted carefully. The price impact is not based on a full redispatch of the system, but such a full redispatch is practically impossible as it would require reconsideration of all dispatch decisions and unit commitments. The markup impact includes the maximum impact of the identified markup conduct on a unit-by-unit basis, but the inclusion of negative markup impacts has an offsetting effect. The markup analysis does not distinguish between intervals in which a unit has local market power or has a price impact in an unconstrained interval. The markup analysis is a more general measure of the competitiveness of the Energy Market.

30 This is the same method used to calculate the fuel-cost-adjusted LMP and the components of LMP.

Markup Component of System Price

The price component measure uses load-weighted, price-based LMP and load-weighted LMP computed using cost-based offers for all marginal units. The price component of markup is computed by calculating the system price, based on the price-based offers of the marginal units and comparing that to the system price, based on the cost-based offers of the marginal units. Both results are compared to the actual system price to determine how much of the LMP can be attributed to markup.

Table 2-35 shows the markup component of average prices and of average monthly on-peak and off-peak prices. In 2007, $5.86 per MWh of the PJM load-weighted average LMP was attributable to markup. In 2007, the markup component of LMP was $2.91 per MWh off peak and $8.59 per MWh on peak. Of the markup component, $0.57 per MWh, or 10 percent, occurred on high-load days. Markup on high-load days is likely to be the result of appropriate scarcity pricing rather than market power.[31]

Table 2-35 Monthly markup components of load-weighted LMP: Calendar year 2007

	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
Jan	$1.85	$3.22	$0.36
Feb	$6.54	$10.18	$2.82
Mar	$5.93	$8.20	$3.53
Apr	$6.75	$9.78	$3.55
May	$3.39	$5.85	$0.54
Jun	$3.50	$5.51	$1.18
Jul	$4.70	$6.71	$2.55
Aug	$5.37	$7.04	$3.23
Sep	$5.79	$9.33	$2.43
Oct	$10.09	$14.06	$5.18
Nov	$10.44	$15.23	$5.47
Dec	$6.95	$9.92	$4.30
2007	$5.86	$8.59	$2.91

Markup Component of Zonal Prices

The annual average price component of unit markup is shown for each zone in Table 2-36. The smallest zonal all hours' markup component was in the DLCO Control Zone, $3.95 per MWh, while the highest all hours' zonal markup component was in the RECO Control Zone, $7.33 per MWh. On peak, the smallest zonal markup was in the DLCO Control Zone, $6.56 per MWh, while the highest markup was in the RECO Control Zone, $10.18 per MWh. Off peak, the smallest zonal markup was in the DLCO Control Zone, $1.16 per MWh, while the highest markup was in the RECO Control Zone, $3.94 per MWh. The MMU calculates explicit measures of the impact of marginal unit markups on LMP. The price impact of markup must be

31 For a definition and list of high-load days, see the *2007 State of the Market Report*, Volume II, Section 3, "Energy Market, Part 2," at "High-Load Events, Scarcity and Scarcity Pricing Events." For the analysis of components of LMP, 25 days are included when high-load days are referenced. These days are June 1, 26 and 27; July 9, 10, 18, 26, 27, 30 and 31; and August 1 to 3, 6 to 10, 13, 15 to 17, 24, 28 and 29, 2007. The three scarcity hours on August 8 are not included.

interpreted carefully. The markup impact includes the maximum impact of the identified markup conduct on a unit-by-unit basis, but the inclusion of negative markup impacts has an offsetting effect. The markup analysis does not distinguish between intervals in which a unit has local market power or has a price impact in an unconstrained interval.

Table 2-36 Average zonal markup component: Calendar year 2007

	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
AECO	$6.43	$9.22	$3.46
AEP	$4.57	$7.03	$2.02
AP	$4.81	$6.86	$2.65
BGE	$6.93	$9.89	$3.80
ComEd	$4.73	$7.23	$1.96
DAY	$4.86	$7.42	$2.02
DLCO	$3.95	$6.56	$1.16
Dominion	$6.61	$9.56	$3.47
DPL	$6.69	$9.69	$3.51
JCPL	$6.75	$9.57	$3.57
Met-Ed	$6.27	$8.88	$3.40
PECO	$6.74	$9.74	$3.50
PENELEC	$5.56	$8.22	$2.69
Pepco	$6.83	$9.62	$3.78
PPL	$6.41	$9.15	$3.43
PSEG	$7.02	$10.07	$3.62
RECO	$7.33	$10.18	$3.94

Markup by System Price Levels

Table 2-37 shows the average markup component of observed price when the PJM system LMP was in the identified price range.

Table 2-37 Average markup (By price category): Calendar year 2007

	Average Markup Component	Frequency
Below $20	($1.83)	3%
$20 to $39.99	($0.56)	35%
$40 to $59.99	$3.70	23%
$60 to $79.99	$7.88	18%
$80 to $99.99	$12.19	12%
$100 to $119.99	$15.24	5%
$120 to $139.99	$15.50	2%
$140 to $159.99	$21.57	1%
Above $160	$38.09	1%

Exempt Unit Markup

PJM's offer-capping rules provide that specific units are exempt from offer capping, based on their date of construction. During 2005, two orders issued by the FERC modified the rules governing exemptions from the offer-capping rules. In the 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."[32] 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."[33] In the July 5, 2005, order, the FERC modified the dates governing unit exemptions by zone.[34] The effect of these orders was to reduce the number of units exempt from local market power mitigation rules from 215 to 56 as of the end of 2005 and that number did not change in 2006 or in 2007.

Table 2-38 compares the markup components of price of exempt and non-exempt units in 2007. Of the 56 generators that are exempt from offer capping, 44 were marginal in 2007. The 44 marginal exempt units accounted for $1.34, 23 percent, of the total markup component of LMP in 2007. Of the 44 units, the top eight exempt units contributed 86 percent of the total markup component of exempt units, or 20 percent of the total markup component for all of PJM. The average markup per exempt unit is about four times higher than for non-exempt units, and the average markup for the top eight exempt units is about 21 times higher than for non-exempt units. This analysis does not address whether these units would have been offer

32 110 FERC ¶ 61,053 (2005).
33 110 FERC ¶ 61,053 (2005).
34 112 FERC ¶ 61,031 (2005).

capped had they not been exempt and therefore does not address how much the contribution to LMP would have changed if the exemption had been removed. The markup analysis does not distinguish between intervals in which a unit has local market power or has a price impact in an unconstrained interval. The markup analysis is a more general measure of the competitiveness of the Energy Market.

Table 2-38 Comparison of exempt and non-exempt markup component: Calendar year 2007

	Units Marginal	Markup Component
Non-exempt units	684	$4.52
Exempt units	44	$1.34

Frequently Mitigated Unit and Associated Unit Adders – Component of Price

On January 25, 2005, the FERC ordered that frequently offer-capped units be provided additional compensation as a form of scarcity pricing, consistent with a recommendation of the MMU.[35] A frequently mitigated unit (FMU) was defined to be a unit that was offer capped for 80 percent or more of its run hours during the prior calendar year. FMUs were allowed either a $40 adder to their cost-based offers in place of the 10 percent adder, or the unit-specific, going-forward costs of the affected unit as a cost-based offer.

In the second half of 2005, discussions were held regarding scarcity pricing and local market power mitigation that led to a settlement agreement accepted by the FERC on January 27, 2006.[36] The settlement agreement revised the definition of FMUs to provide for a set of graduated adders associated with increasing levels of offer capping.[37] Units capped for 60 percent or more of their run hours and less than 70 percent are entitled to an adder of either 10 percent of their cost-based offer or $20 per MWh. Units capped 70 percent or more of their run hours and less than 80 percent are entitled to an adder of either 15 percent of their cost-based offer (not to exceed $40) or $30 per MWh. Units capped 80 percent or more of their run hours are entitled to an adder of $40 per MWh or the unit-specific, going-forward costs of the affected unit as a cost-based offer.[38] These categories are designated Tier 1, Tier 2 and Tier 3, respectively.

The settlement agreement further amended the OA to designate associated units (AUs), also at the recommendation of the MMU. An AU is a unit that is electrically and economically identical to an FMU, but does not qualify for the same adder. The settlement agreement provides for monthly designation of FMUs and AUs, where a unit's capping percentage is based on a rolling 12-month average, effective with a one-month lag.[39]

For example, if a generating station had two identical units, one of which was offer capped for more than 80 percent of its run hours, that unit would be designated a Tier 3 FMU. If the second unit were capped for 30 percent of its run hours, that unit would be an AU and receive the same Tier 3 adder as the FMU at the

35 110 FERC ¶ 61,053 (2005).

36 114 FERC ¶ 61,076 (2006).

37 *PJM Interconnection, L.L.C.*, Settlement Agreement, Docket Nos. EL03-236-006, EL04-121-000 (consolidated) (November 16, 2005).

38 OA, Fifth Revised Sheet No. 131B (Effective July 3, 2007).

39 OA, Fifth Revised Sheet No. 132 (Effective July 3, 2007). In 2007, the FERC approved OA revisions to clarify the AU criteria.

site, to ensure that the associated unit is not dispatched in place of the FMU, resulting in no effective adder for the FMU. In the absence of the AU designation, the associated unit would be an FMU after its dispatch and the FMU would be dispatched in its place after losing its FMU designation.

As another example, if a generating station had two identical units, one of which was offer capped for more than 80 percent of its run hours, that unit would be designated a Tier 3 FMU. If the second unit were capped for 72 percent of its run hours, that unit would be eligible for a Tier 2 FMU adder. However, the second unit is an AU to the first unit and would, therefore, be eligible for the higher Tier 3 adder.

Table 2-39 shows the number of FMUs and AUs in each month of 2007. For example, in December 2007, there were 15 FMUs and AUs in Tier 1, 13 FMUs and AUs in Tier 2, and 73 FMUs and AUs in Tier 3.

Table 2-39 Frequently mitigated units and associated units (By month): Calendar year 2007

	FMUs and AUs			Total Eligible
	Tier 1	Tier 2	Tier 3	for Any Adder
January	22	56	53	131
February	18	49	63	130
March	24	46	58	128
April	16	52	58	126
May	14	62	52	128
June	16	66	46	128
July	15	45	68	128
August	25	30	76	131
September	23	21	81	125
October	13	22	84	119
November	22	13	76	111
December	15	13	73	101

Table 2-40 shows the number of months FMUs and AUS were eligible for any adder (Tier 1, Tier 2 or Tier 3) during 2007. Of the 142 units eligible in at least one month during 2007, 121 units (85 percent) were FMUs or AUs for more than eight months. Approximately two-thirds of the units (93 units or 65 percent) were eligible every month during the year. This demonstrates that the group of FMUs and AUs is fairly stable, although units may move between the tier levels, month-to-month.

Table 2-40 Frequently mitigated units and associated units total months eligible: Calendar year 2007

Months Adder-Eligible	FMU & AU Count
1	5
2	2
3	1
4	5
5	0
6	1
7	2
8	5
9	10
10	10
11	8
12	93
Total	142

Table 2-41 shows the impact of the offer-cap adders for frequently mitigated units and associated units on LMP in each zone.[40] The impact is calculated, using sensitivity factors, by comparing the actual LMP to what the LMP would have been in the absence of the FMU and AU adders. The zone reflects where the price impact occurs, not the location of the FMUs or AUs. The additional energy cost is the affected load multiplied by the locational price impacts. The MMU calculates explicit measures of the impact of the FMU and AU adders on LMP. The price impact must be interpreted carefully. The price impact includes the maximum impact of the FMU and AU adders.

40 The PJM total includes load at certain buses which are dynamically dispatched by PJM, but which are not part of a PJM control zone. As a result, the PJM total is not equal to the sum of zonal totals in this analysis.

Table 2-41 Cost impact of FMUs and AUs (By zone): Calendar year 2007

	FMU and AU Marginal Energy Impacts (Millions)	Total Energy Cost (Millions)	Percent	LMP Impact
AECO	$21.88	$837.91	2.61%	$1.87
AEP	$35.83	$7,371.00	0.49%	$0.24
AP	$36.99	$2,986.31	1.24%	$0.76
BGE	$41.15	$2,659.35	1.55%	$1.18
ComEd	$23.93	$5,235.91	0.46%	$0.23
DAY	$4.48	$969.72	0.46%	$0.23
DLCO	$1.77	$721.39	0.25%	$0.12
DPL	$15.30	$1,366.27	1.12%	$0.78
Dominion	$80.60	$6,996.28	1.15%	$0.84
JCPL	$21.30	$1,811.21	1.18%	$0.85
Met-Ed	$16.52	$1,093.38	1.51%	$1.05
PECO	$27.28	$2,871.28	0.95%	$0.64
PENELEC	$10.09	$1,059.66	0.95%	$0.55
Pepco	$38.81	$2,509.29	1.55%	$1.19
PPL	$30.38	$2,935.57	1.03%	$0.68
PSEG	$32.18	$3,404.72	0.95%	$0.67
RECO	$0.92	$119.45	0.77%	$0.54
PJM	$433.41	$44,120.82	0.98%	$0.61

Markup Component of Price on High-Load Days

Scarcity exists when the total demand for power approaches the generating capability of the system. Scarcity pricing means that market prices reflect the fact that the system is close to its available capacity and that competitive prices may exceed accounting, short-run marginal costs. Under the current PJM rules, high prices, or scarcity pricing, result from high offers by individual generation owners for specific units when the system is close to its available capacity. These offers give the aggregate energy supply curve its steep upward sloping tail.[41] As demand increases and units with higher markups and higher offers are required to meet demand, prices increase. As a result, markup on high-load days is likely to be the result of appropriate scarcity pricing rather than market power.[42] Under the current PJM rules, administrative scarcity pricing, based on the scarcity pricing provisions in the Tariff, results when PJM takes identified emergency actions and is based on the highest offer of an operating unit.[43]

41 See the *2007 State of the Market Report*, Volume II, Section 2, “Energy Market, Part I,” at Figure 2-1,“Average PJM aggregate supply curves: Summers 2006 and 2007.”

42 For a definition of high-load days, see the *2007 State of the Market Report,* Volume II, Section 3, “Energy Market, Part 2,” at “2007 High-Load Events, Scarcity and Scarcity Pricing Events.”

43 See the *2007 State of the Market Report,* Volume II, Section 3, “Energy Market, Part 2,” at “2007 High-Load Events, Scarcity and Scarcity Pricing Events.” This administrative scarcity pricing, as defined by PJM rules, is one type of the broader category of scarcity pricing.

The markup component of price is higher during peak-demand periods. Figure 2-5 shows the hourly load-weighted, average markup component of price for the summer of 2007. [44]

Figure 2-5 Average hourly markup and load: Summer 2007

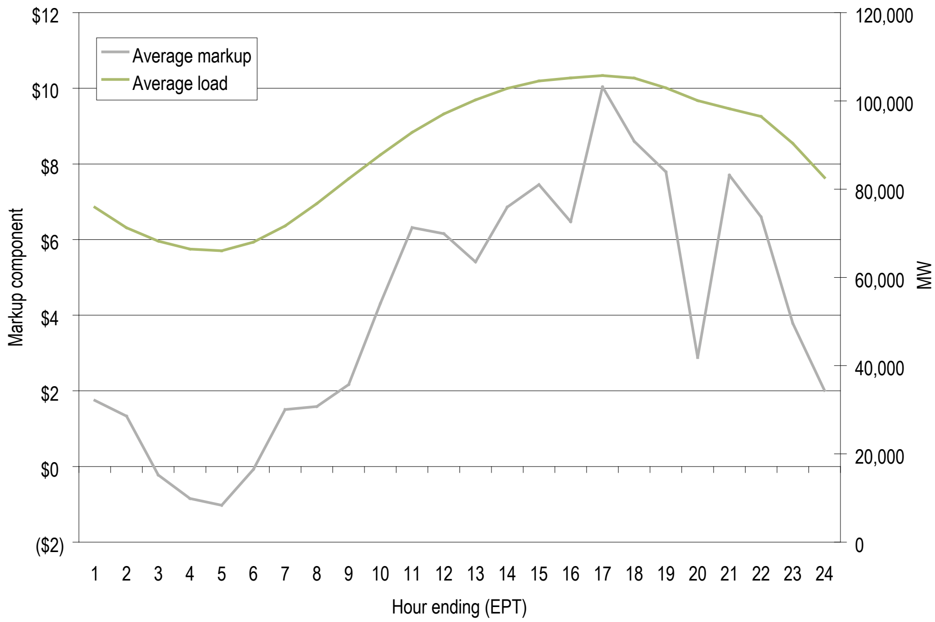


Table 2-42 shows that $0.57 per MWh, or 10 percent, of the total markup component of price occurred on high-load days. In addition, for non-exempt units, about 7 percent of the total markup component of price occurs on high-load days. For exempt units, about 19 percent of the total markup component of price occurs on high-load days.

Table 2-42 Markup contribution of exempt and non-exempt units: Calendar year 2007

	Exempt Markup Component	Non-Exempt Markup Component	Total
High-load days	$0.25	$0.32	$0.57
Balance of year	$1.09	$4.20	$5.29
Total	$1.34	$4.52	$5.86

44 Summer is defined as from June 1, 2007, to September 1, 2007.

Market Performance: Load and LMP

The PJM system load and LMP reflect the configuration of the entire RTO. The PJM Energy Market includes the Real-Time Energy Market and the Day-Ahead Energy Market, which started on January 1, 1998, and June 1, 2000, respectively.

Load

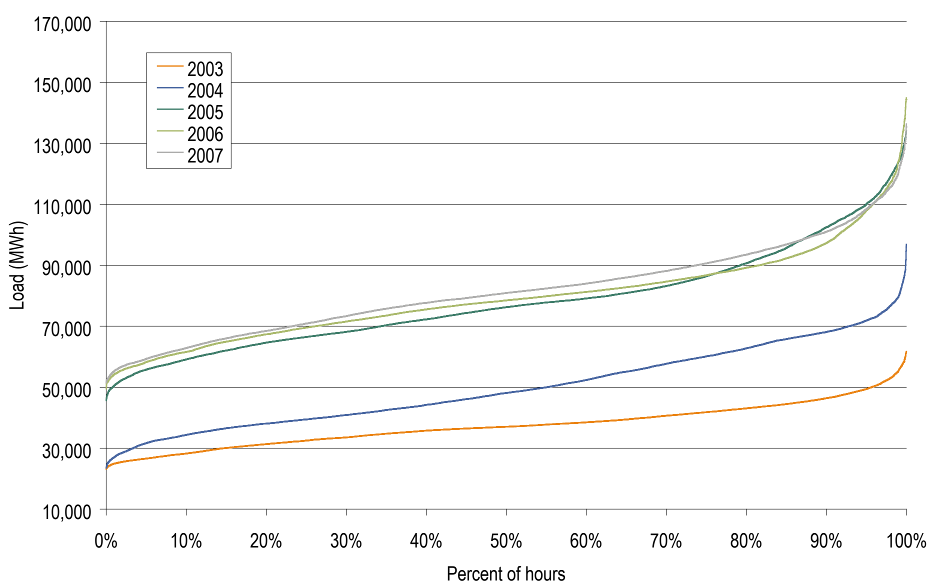
Real-Time Load

PJM real-time load is the total hourly accounting load in real time.[45]

PJM Real-Time Load Duration

Figure 2-6 shows PJM real-time load duration curves from 2003 to 2007. A load duration curve shows the percent of hours that load was at, or below, a given level for the year.

Figure 2-6 PJM real-time load duration curves: Calendar years 2003 to 2007



45 All real-time load data in Section 2, "Energy Market, Part 1," "Market Performance: Load and LMP" are based on PJM accounting load. See the *2007 State of the Market Report*, Volume II, Appendix I, "Load Definitions," for detailed definitions of accounting load.

PJM Real-Time, Annual Average Load

Table 2-43 presents summary real-time load statistics for the 10-year period 1998 to 2007. The average load of 81,681 MWh in 2007 was 2.8 percent higher than the 2006 annual average hourly load. This average load was based on the PJM hourly accounting load. Before June 1, 2007, transmission losses were included in accounting load. After June 1, 2007, transmission losses were excluded from accounting load because of the implementation of marginal loss pricing. The average 2007 load of 81,681 MWh includes losses prior to June 1 but does not include losses after June 1, 2007. If transmission losses had been included, the real-time, annual average load for 2007 would have been 82,857 MWh, which was 4.3 percent higher than the 2006 real-time, annual average hourly load.[46]

Table 2-43 PJM real-time average load: Calendar years 1998 to 2007

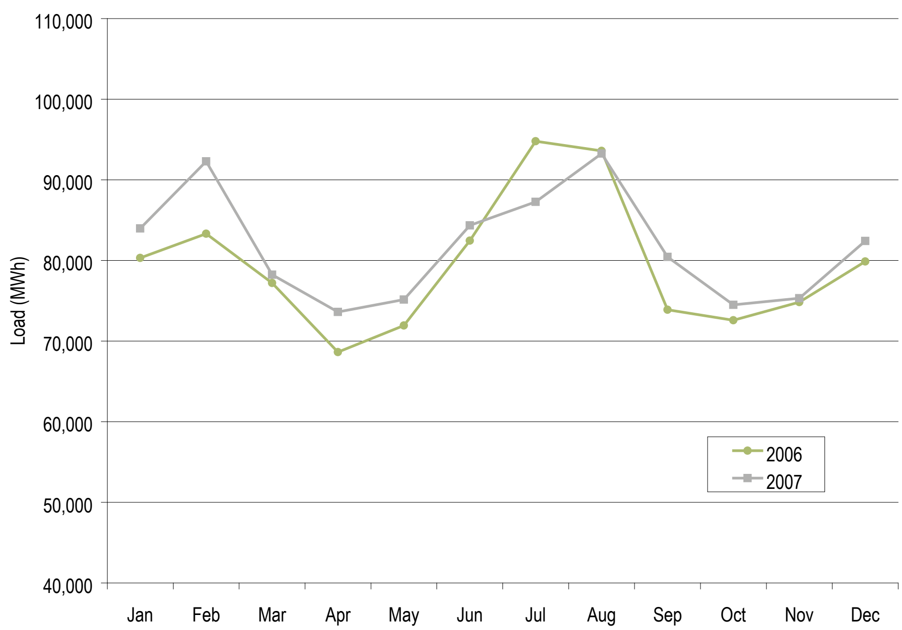
	PJM Real-Time Load (MWh)			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	28,577	28,653	5,512	NA	NA	NA
1999	29,640	29,341	5,956	3.7%	2.4%	8.1%
2000	30,113	30,170	5,529	1.6%	2.8%	(7.2%)
2001	30,297	30,219	5,873	0.6%	0.2%	6.2%
2002	35,797	34,804	7,964	18.2%	15.2%	35.6%
2003	37,395	37,029	6,834	4.5%	6.4%	(14.2%)
2004	49,963	48,103	13,004	33.6%	29.9%	90.3%
2005	78,150	76,247	16,296	56.4%	58.5%	25.3%
2006	79,471	78,473	14,534	1.7%	2.9%	(10.8%)
2007	81,681	80,914	14,618	2.8%	3.1%	0.6%

46 Accounting load is used here because PJM uses accounting load in the settlement process, which determines how much load customers pay for. In addition, the use of accounting load with losses before June 1, and without losses after June 1, 2007, is consistent with PJM's calculation of LMP, which excludes losses prior to June 1 and includes losses after June 1.

PJM Real-Time, Monthly Average Load

Figure 2-7 compares the real-time, monthly average hourly loads of 2007 with those of 2006.

Figure 2-7 PJM real-time average load: Calendar years 2006 to 2007



PJM real-time load is significantly affected by temperature. PJM uses the Temperature-Humidity Index (THI) as the weather variable in the PJM load forecast model for the cooling season (June, July and August).[47] THI is a measure of effective temperature using temperature and relative humidity. Table 2-44 shows the monthly minimum, average and maximum of the PJM hourly THI for the cooling months in 2006 and 2007. When comparing 2007 to 2006, changes in THI were mixed, consistent with the changes in load. For the cooling months of 2007, the average THI was 70.90, 0.6 percent lower than the average 71.30 THI for 2006. However, the maximum THI (82.84) and minimum THI (55.46) in 2007 were 1.8 percent lower and 4.2 percent higher, respectively, than the maximum THI (84.39) and minimum THI (53.22) in 2006 during the cooling months.

47 Temperature and relative humidity data that were used to calculate THI were obtained from Meteorlogix. PJM hourly THI is the weighted-average zonal hourly THI weighted by average, annual peak zonal share (Coincident Factor) from 1998 to the year for which the calculation is made. For additional information on THI calculations, see PJM. "Manual 19: Load Forecasting and Analysis" (June 1, 2007), Section 4, pp. 18-23.

Table 2-44 Monthly minimum, average and maximum of PJM hourly THI: Cooling periods of 2006 and 2007

	2006			2007			Difference		
	Min	Avg	Max	Min	Avg	Max	Min	Avg	Max
Jun	53.22	67.82	78.65	55.46	69.18	80.94	4.2%	2.0%	2.9%
Jul	58.23	73.63	82.17	55.78	70.92	80.29	(4.2%)	(3.7%)	(2.3%)
Aug	58.71	72.32	84.39	61.60	72.53	82.84	4.9%	0.3%	(1.8%)

Day-Ahead Load

In the PJM Day-Ahead Energy Market, three types of financially binding demand bids are made and cleared:

- Fixed-Demand Bid. Bid to purchase a defined MWh level of energy, regardless of LMP.

- Price-Sensitive Bid. Bid to purchase a defined MWh level of energy only up to a specified LMP, above which the load bid is zero.

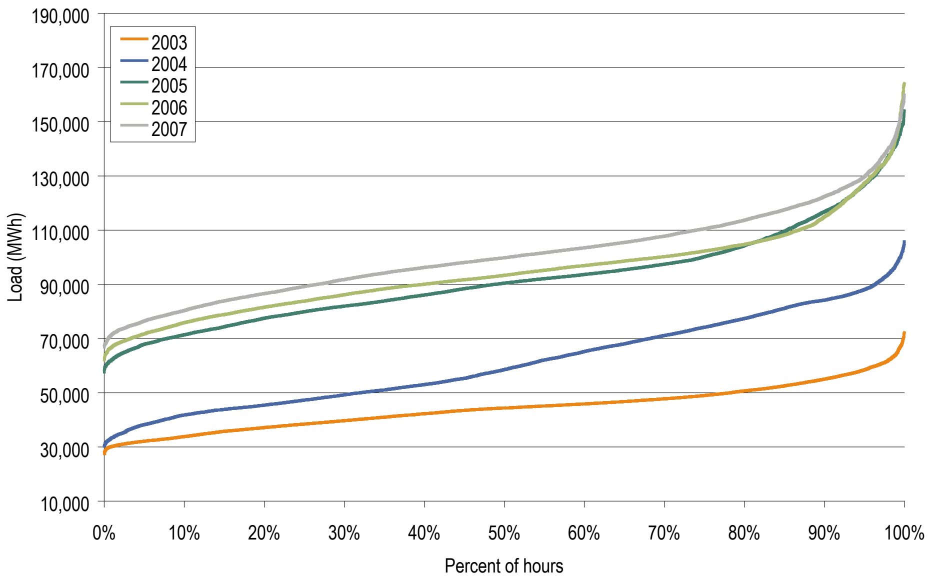
- Decrement Bid (DEC). Financial bid to purchase a defined MWh level of energy up to a specified LMP, above which the bid is zero. A decrement bid is a financial bid that can be submitted by any market participant.

PJM day-ahead load is the hourly total of the above three types of cleared demand bids.

PJM Day-Ahead Load Duration

Figure 2-8 shows PJM day-ahead load duration curves from 2003 to 2007.

Figure 2-8 PJM day-ahead load duration curves: Calendar years 2003 to 2007



PJM Day-Ahead, Annual Average Load

Table 2-45 presents summary day-ahead load statistics for the five-year period 2003 to 2007. The average load of 100,912 MWh in 2007 was 6.5 percent higher than the 2006 annual average load. The cleared decrement bids, fixed demand and price-sensitive demand in 2007 were 18.8 percent, 3.6 percent and 1.0 percent higher than the corresponding loads in 2006, respectively.

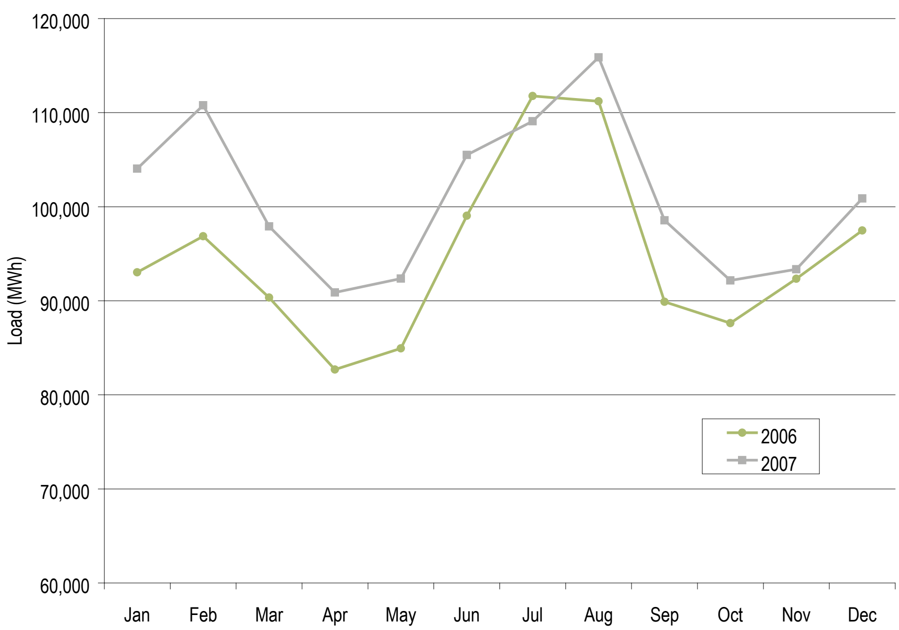
Table 2-45 PJM day-ahead average load: Calendar years 2003 to 2007

	PJM Day-Ahead Load (MWh)			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2003	44,328	44,362	7,877	NA	NA	NA
2004	61,034	58,544	16,320	37.7%	32.0%	107.2%
2005	92,002	90,424	17,382	50.7%	54.5%	6.5%
2006	94,793	93,331	16,048	3.0%	3.2%	(7.7%)
2007	100,912	99,799	16,190	6.5%	6.9%	0.9%

PJM Day-Ahead, Monthly Average Load

Figure 2-9 compares the day-ahead, monthly average loads of 2007 with those of 2006.

Figure 2-9 PJM day-ahead average load: Calendar years 2006 to 2007



Real-Time and Day-Ahead Load

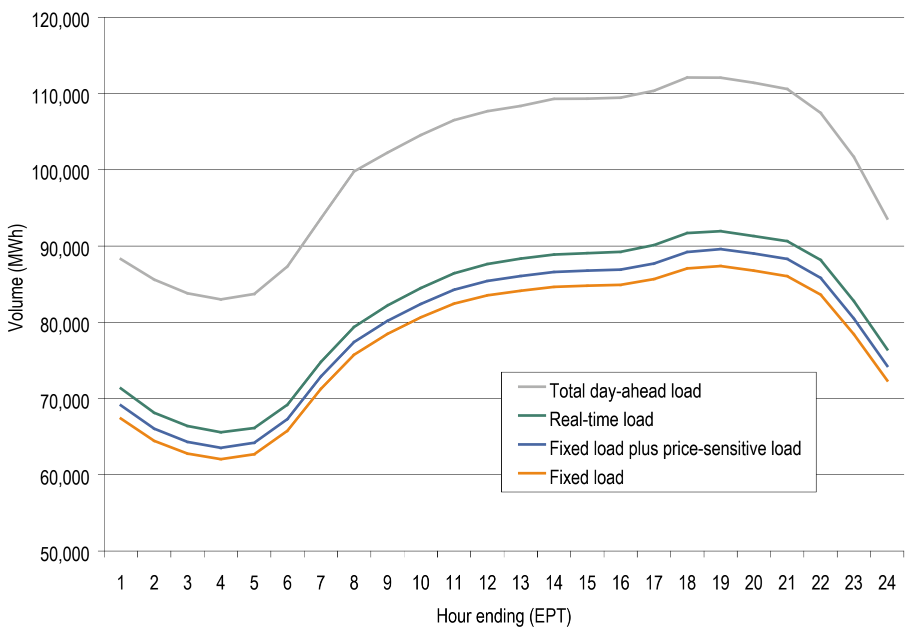
Table 2-46 presents summary statistics for the 2007 day-ahead and real-time loads and the average difference between them. The sum of day-ahead cleared fixed demand and price-sensitive demand averaged 2,184 MWh less than real-time average load. Total day-ahead load (the sum of the three types of cleared demand bids) averaged 19,231 MWh more than real-time load. Table 2-46 shows that, at 76.9 percent, fixed demand was the largest component of day-ahead load. At 1.9 percent, price-sensitive load was the smallest component, with cleared decrement bids accounting for the remaining 21.2 percent of day-ahead load.

Table 2-46 Cleared day-ahead and real-time load (MWh): Calendar year 2007

	Day Ahead				Real Time	Average Difference	
	Cleared Fixed Demand	Cleared Price Sensitive	Cleared DEC Bid	Total Load	Total Load	Total Load	Total Load Minus DEC Bid
Average	77,628	1,869	21,415	100,912	81,681	19,231	(2,184)
Median	77,112	1,788	20,989	99,799	80,914	18,885	(2,104)
Standard deviation	13,659	503	2,733	16,190	14,618	1,572	(1,161)

Figure 2-10 shows the average 2007 hourly cleared volumes of fixed-demand bids, the sum of cleared fixed-demand and price-sensitive bids, total day-ahead load and real-time load. During 2007, real-time, hourly average load was higher than cleared fixed-demand load plus cleared price-sensitive load in the Day-Ahead Energy Market, although the reverse was true for 10.5 percent of the hours. When cleared decrement bids are included, day-ahead load always exceeded real-time load.

Figure 2-10 Day-ahead and real-time loads (Average hourly volumes): Calendar year 2007



Real-Time and Day-Ahead Generation

Real-time generation is the actual production of electricity during the operating day.

In the Day-Ahead Energy Market,[48] three types of financially binding generation offers are made and cleared:

- Self-Scheduled. Offer to supply a fixed block of MWh that must run from a specific unit, or as a minimum amount of MWh that must run on a specific unit that also has a dispatchable component above the minimum.[49]

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

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

48 All references to day-ahead generation and increment offers are presented in cleared MWh in the "Real-Time and Day-Ahead Generation" portion of the *2007 State of the Market Report,* Volume II, Section 2, "Energy Market, Part 1."

49 The definition of self-scheduled is based on documentation from PJM. "eMKT User Guide" (June 2007), pp. 49-51.

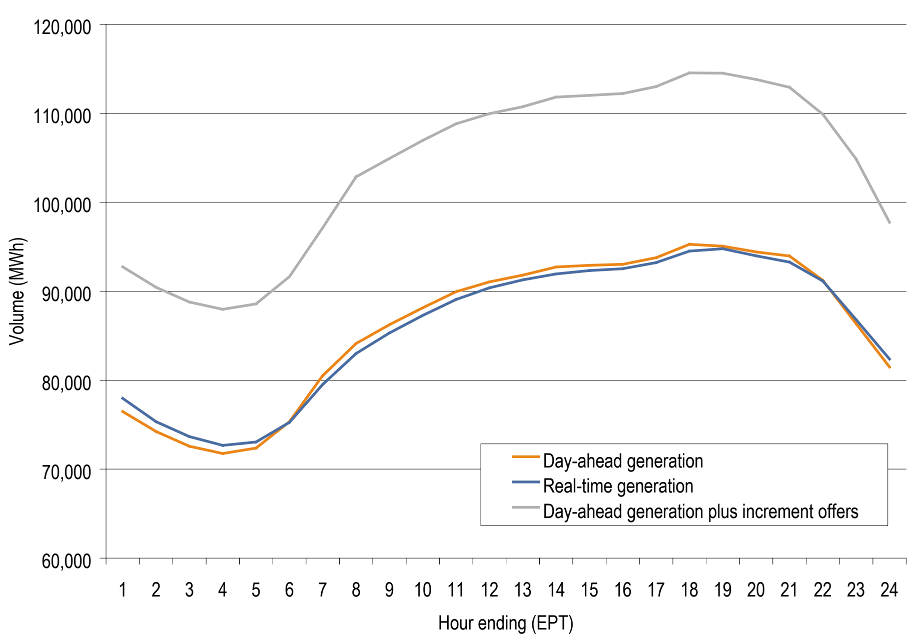
Table 2-47 presents summary statistics for 2007 day-ahead and real-time generation and the average differences between them. Day-ahead cleared generation from physical units averaged 170 MWh higher than real-time generation. Day-ahead cleared generation plus cleared INC offers averaged 18,256 MWh more than real-time generation. Table 2-47 also shows that cleared generation and INC offers accounted for 82.6 percent and 17.4 percent of day-ahead supply, respectively.

Table 2-47 Day-ahead and real-time generation (MWh): Calendar year 2007

	Day Ahead			Real Time	Average Difference	
	Cleared Generation	Cleared INC Offer	Cleared Generation Plus INC Offer	Generation	Cleared Generation	Cleared Generation Plus INC Offer
Average	86,030	18,086	104,116	85,860	170	18,256
Median	84,743	17,708	102,517	84,046	697	18,471
Standard deviation	14,085	2,463	16,071	14,018	67	2,053

Figure 2-11 shows average hourly cleared volumes of day-ahead generation, day-ahead generation plus increment offers and real-time generation for 2007.[50] Day-ahead generation is all the self-scheduled and generator offers cleared in the Day-Ahead Energy Market. During 2007, real-time, hourly average generation was lower than day-ahead generation from physical units, although the reverse was true for 45.1 percent of the hours. When cleared increment offers are included, average hourly total day-ahead cleared MW offers exceeded real-time generation.

Figure 2-11 Day-ahead and real-time generation (Average hourly volumes): Calendar year 2007



50 Generation data are the sum of MWh at every generation bus in PJM with positive output.

Locational Marginal Price (LMP)

The conduct of individual market entities within a market structure is reflected in market prices. The overall level of prices is a good general indicator of market performance, although overall price results must be interpreted carefully because of the multiple factors that affect them.[51]

Real-Time LMP

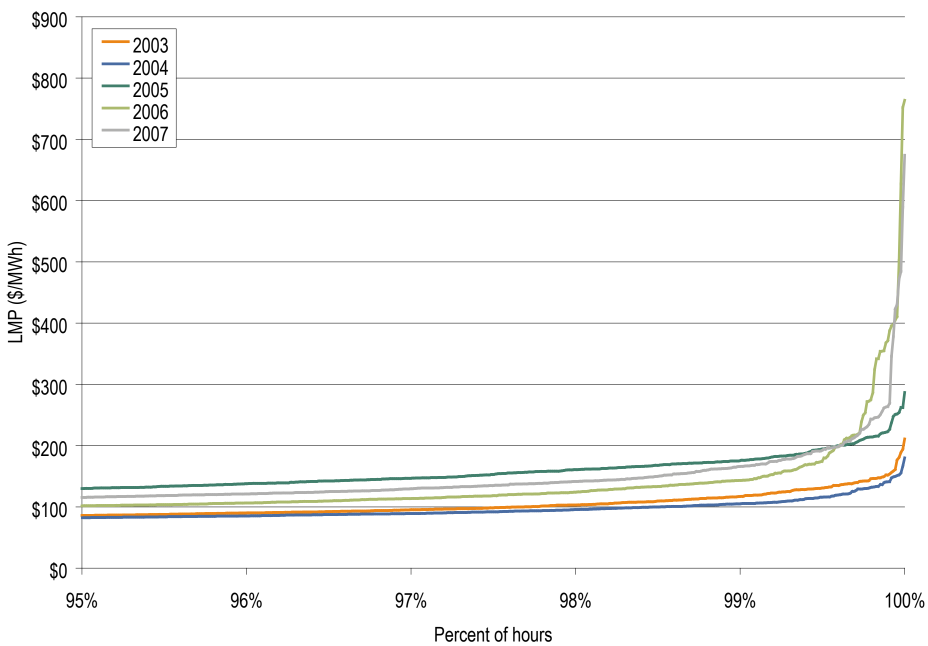
Real-time LMP is the hourly LMP for the PJM Real-Time Energy Market.

Real-Time Average LMP

PJM Real-Time LMP Duration

A price duration curve shows the percent of hours when LMP is at, or below, a given price for the year. Figure 2-12 presents price duration curves for hours above the 95th percentile from 2003 to 2007. As Figure 2-12 shows, LMPs were less than $100 per MWh during 95 percent or more of the hours for the years 2003 and 2004 and less than $150 during 95 percent or more of the hours for the years 2005 to 2007.[52]

Figure 2-12 Price duration curves for the PJM Real-Time Energy Market during hours above the 95th percentile: Calendar years 2003 to 2007



51 See the *2007 State of the Market Report,* Volume II, Appendix C, "Energy Market," for methodological background, detailed price data and comparisons and Appendix H, "Calculating Locational Marginal Price" for more information on how bus LMPs are aggregated to system LMPs.

52 See the *2007 State of the Market Report,* Volume II, Appendix C, "Energy Market," at Table C-4, "Frequency distribution by hours of PJM Real-Time Energy Market LMP (Dollars per MWh): Calendar years 2003 to 2007."

PJM Real-Time, Annual Average LMP

Table 2-48 shows the PJM real-time, annual, simple average LMP for the 10-year period 1998 to 2007.[53] The system simple average LMP for 2007 was 16.9 percent higher than the 2006 annual average, $57.58 per MWh versus $49.27 per MWh.

Table 2-48 PJM real-time, simple average LMP (Dollars per MWh): Calendar years 1998 to 2007

	Real-Time LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$21.72	$16.60	$31.45	NA	NA	NA
1999	$28.32	$17.88	$72.42	30.4%	7.7%	130.3%
2000	$28.14	$19.11	$25.69	(0.6%)	6.9%	(64.5%)
2001	$32.38	$22.98	$45.03	15.1%	20.3%	75.3%
2002	$28.30	$21.08	$22.40	(12.6%)	(8.3%)	(50.3%)
2003	$38.27	$30.79	$24.71	35.2%	46.1%	10.3%
2004	$42.40	$38.30	$21.12	10.8%	24.4%	(14.5%)
2005	$58.08	$47.18	$35.91	37.0%	23.2%	70.0%
2006	$49.27	$41.45	$32.71	(15.2%)	(12.1%)	(8.9%)
2007	$57.58	$49.92	$34.60	16.9%	20.4%	5.8%

Zonal Real-Time, Annual Average LMP

Table 2-49 shows PJM zonal real-time, simple average LMP for 2006 and 2007. The largest zonal increase was in the JCPL Control Zone which experienced a $13.94 increase over 2006 and the smallest increase was in the ComEd Control Zone which experienced a $4.19 increase over 2006.

53 The system annual, simple average LMP is the average of the hourly LMP without any weighting. The only exception is that market-clearing prices (MCPs) are included for January to April 1998. MCP was the single market-clearing price calculated by PJM prior to implementation of LMP.

Table 2-49 Zonal real-time, simple average LMP (Dollars per MWh): Calendar years 2006 to 2007

	2006	2007	Difference	Difference as Percent of 2006
AECO	$55.53	$65.02	$9.49	17.1%
AEP	$42.24	$46.55	$4.31	10.2%
AP	$48.71	$57.45	$8.74	17.9%
BGE	$57.40	$69.79	$12.39	21.6%
ComEd	$41.52	$45.71	$4.19	10.1%
DAY	$41.21	$46.47	$5.26	12.8%
DLCO	$39.34	$43.93	$4.59	11.7%
Dominion	$56.44	$66.75	$10.31	18.3%
DPL	$53.09	$64.15	$11.06	20.8%
JCPL	$51.80	$65.74	$13.94	26.9%
Met-Ed	$52.66	$64.57	$11.91	22.6%
PECO	$52.40	$62.60	$10.20	19.5%
PENELEC	$46.64	$54.80	$8.16	17.5%
Pepco	$58.85	$70.33	$11.48	19.5%
PPL	$51.52	$62.02	$10.50	20.4%
PSEG	$54.57	$65.92	$11.35	20.8%
RECO	$53.88	$64.85	$10.97	20.4%

Real-Time, Annual Average LMP by Jurisdiction

Table 2-50 shows the real-time, simple average LMP for all or part of the jurisdictions within the PJM footprint during 2006 and 2007. The largest increase was in Maryland which experienced a $12.06 increase over 2006, and the smallest increase was in Tennessee which experienced a $2.68 increase over 2006.

Table 2-50 Jurisdiction real-time, simple average LMP (Dollars per MWh): Calendar years 2006 to 2007

	2006	2007	Difference	Difference as Percent of 2006
Delaware	$52.74	$63.45	$10.71	20.3%
Illinois	$41.52	$45.71	$4.19	10.1%
Indiana	$41.65	$46.24	$4.59	11.0%
Kentucky	$42.52	$46.52	$4.00	9.4%
Maryland	$57.55	$69.61	$12.06	21.0%
Michigan	$41.73	$46.82	$5.09	12.2%
New Jersey	$53.94	$65.78	$11.84	22.0%
North Carolina	$54.06	$62.58	$8.52	15.8%
Ohio	$40.98	$45.69	$4.71	11.5%
Pennsylvania	$49.38	$58.72	$9.34	18.9%
Tennessee	$44.64	$47.32	$2.68	6.0%
Virginia	$54.83	$63.83	$9.00	16.4%
West Virginia	$42.48	$48.39	$5.91	13.9%
District of Columbia	$59.05	$70.25	$11.20	19.0%

Hub Real-Time, Annual Average LMP

Table 2-51 shows the real-time, simple average LMPs at the PJM hubs for 2006 and 2007. Hub prices are average LMPs across a defined set of buses, created to provide market participants with trading points that exhibited greater price stability than individual buses. The largest price increase was for the New Jersey Hub which experienced an $11.85 increase over 2006, and the smallest increase was for the AEP Gen Hub which experienced a $3.44 increase over 2006.

Table 2-51 Hub real-time, simple average LMP (Dollars per MWh): Calendar years 2006 to 2007

	2006	2007	Difference	Difference as Percent of 2006
AEP Gen Hub	$40.70	$44.14	$3.44	8.5%
AEP-DAY Hub	$41.43	$46.25	$4.82	11.6%
Chicago Gen Hub	$41.37	$45.11	$3.74	9.0%
Chicago Hub	$41.53	$45.76	$4.23	10.2%
Dominion Hub	$55.51	$64.65	$9.14	16.5%
Eastern Hub	$53.07	$63.92	$10.85	20.4%
N Illinois Hub	$41.45	$45.47	$4.02	9.7%
New Jersey Hub	$53.77	$65.62	$11.85	22.0%
Ohio Hub	$41.44	$46.18	$4.74	11.4%
West Interface Hub	$45.56	$51.67	$6.11	13.4%
Western Hub	$51.11	$59.77	$8.66	16.9%

Real-Time, Load-Weighted, Average LMP

Higher demand (load) generally results in higher prices, all else constant. As a result, load-weighted, average prices are generally higher than simple average prices. Load-weighted LMP reflects the average LMP paid for actual MWh consumed during a year. Load-weighted, average LMP is the average of PJM hourly LMPs, each weighted by the PJM total hourly load.

PJM Real-Time, Annual, Load-Weighted, Average LMP

Table 2-52 shows the PJM real-time, annual, load-weighted, average LMP for the 10-year period 1998 to 2007. The load-weighted, average system LMP for 2007 was 15.6 percent higher than the 2006 annual, load-weighted, average, $61.66 per MWh versus $53.35 per MWh.

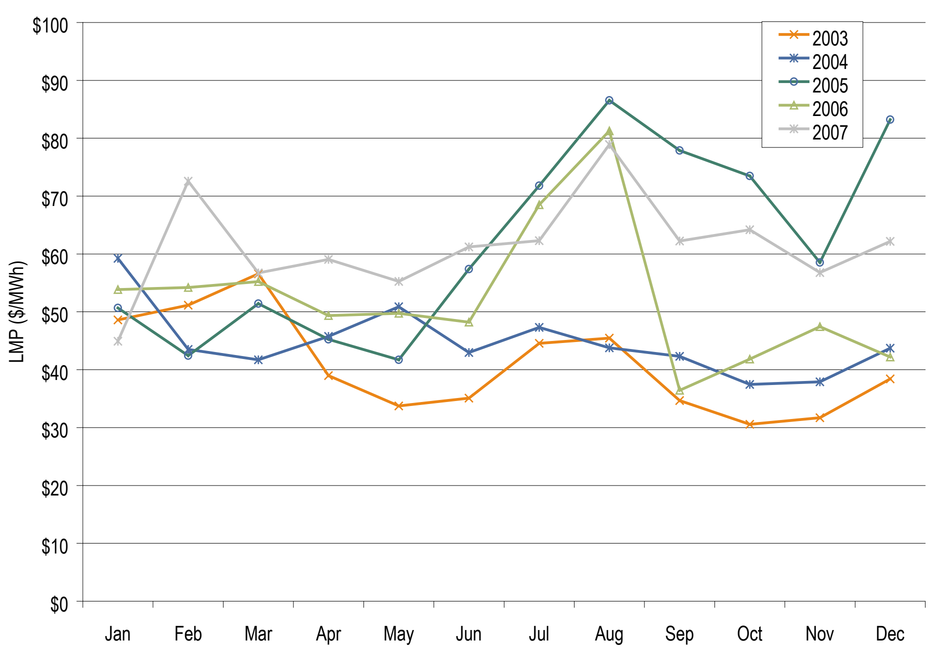
Table 2-52 PJM real-time, annual, load-weighted, average LMP (Dollars per MWh): Calendar years 1998 to 2007

	Real-Time, Load-Weighted, Average LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$24.16	$17.60	$39.29	NA	NA	NA
1999	$34.07	$19.02	$91.49	41.0%	8.1%	132.9%
2000	$30.72	$20.51	$28.38	(9.8%)	7.8%	(69.0%)
2001	$36.65	$25.08	$57.26	19.3%	22.3%	101.8%
2002	$31.58	$23.40	$26.73	(13.8%)	(6.7%)	(53.3%)
2003	$41.23	$34.95	$25.40	30.6%	49.4%	(5.0%)
2004	$44.34	$40.16	$21.25	7.5%	14.9%	(16.3%)
2005	$63.46	$52.93	$38.10	43.1%	31.8%	79.3%
2006	$53.35	$44.40	$37.81	(15.9%)	(16.1%)	(0.8%)
2007	$61.66	$54.66	$36.94	15.6%	23.1%	(2.3%)

PJM Real-Time, Monthly, Load-Weighted, Average LMP

Figure 2-13 shows the PJM real-time, monthly, load-weighted LMP from 2003 through 2007.

Figure 2-13 PJM real-time, monthly, load-weighted, average LMP: Calendar years 2003 to 2007



Zonal Real-Time, Annual, Load-Weighted, Average LMP

Table 2-53 shows PJM zonal real-time, load-weighted, average LMP for 2006 and 2007. The largest zonal increase was in the JCPL Control Zone which experienced a $13.76 increase over 2006, and the smallest increase was in the ComEd Control Zone which experienced a $4.23 increase over 2006.

Table 2-53 Zonal real-time, annual, load-weighted, average LMP (Dollars per MWh): Calendar years 2006 to 2007

	2006	2007	Difference	Difference as Percent of 2006
AECO	$62.32	$71.43	$9.11	14.6%
AEP	$44.85	$49.51	$4.66	10.4%
AP	$52.06	$61.20	$9.14	17.6%
BGE	$63.54	$75.95	$12.41	19.5%
ComEd	$45.05	$49.28	$4.23	9.4%
DAY	$44.28	$49.95	$5.67	12.8%
DLCO	$42.31	$47.23	$4.92	11.6%
Dominion	$62.27	$72.51	$10.24	16.4%
DPL	$58.28	$69.35	$11.07	19.0%
JCPL	$58.12	$71.88	$13.76	23.7%
Met-Ed	$57.18	$69.38	$12.20	21.3%
PECO	$57.03	$67.13	$10.10	17.7%
PENELEC	$49.13	$57.71	$8.58	17.5%
Pepco	$65.57	$76.75	$11.18	17.1%
PPL	$55.49	$66.12	$10.63	19.2%
PSEG	$59.73	$70.80	$11.07	18.5%
RECO	$59.79	$70.69	$10.90	18.2%

Real-Time, Annual, Load-Weighted, Average LMP by Jurisdiction

Table 2-54 shows the real-time, load-weighted, average LMPs for all or part of the jurisdictions within the PJM footprint during 2006 and 2007[54]. The largest increase was in Maryland which experienced a $12.00 increase over 2006, and the smallest increase was in Tennessee which experienced a $2.41 increase over 2006.

54 The PJM footprint includes 17 control zones. Each control zone is in one or more states or the District of Columbia, but such jurisdictions generally are not entirely covered by PJM control zones. The term jurisdiction is used here to refer to the states in which one or more of these control zones are located. For maps showing the PJM footprint and its control zones, see the *2007 State of the Market Report*, Volume II, Appendix A, "PJM Geography."

Table 2-54 Jurisdiction real-time, annual, load-weighted, average LMP (Dollars per MWh): Calendar years 2006 to 2007

	2006	2007	Difference	Difference as Percent of 2006
Delaware	$57.49	$68.19	$10.70	18.6%
Illinois	$45.05	$49.27	$4.22	9.4%
Indiana	$43.99	$48.79	$4.80	10.9%
Kentucky	$45.40	$50.16	$4.76	10.5%
Maryland	$64.05	$76.05	$12.00	18.7%
Michigan	$44.78	$50.09	$5.31	11.9%
New Jersey	$59.62	$71.21	$11.59	19.4%
North Carolina	$59.06	$67.95	$8.89	15.1%
Ohio	$43.77	$48.70	$4.93	11.3%
Pennsylvania	$53.05	$62.54	$9.49	17.9%
Tennessee	$47.82	$50.23	$2.41	5.0%
Virginia	$60.18	$69.21	$9.03	15.0%
West Virginia	$44.72	$51.31	$6.59	14.7%
District of Columbia	$64.37	$75.34	$10.97	17.0%

Real-Time, Fuel-Cost-Adjusted, Load-Weighted LMP

Fuel Cost

Changes in LMP can result from changes in the marginal costs of marginal units, the units setting LMP. In general, fuel costs make up between 80 percent and 90 percent of marginal cost depending on generating technology, unit age and other factors. The impact of fuel cost on marginal cost and on LMP depends on the fuel burned by marginal units and changes in fuel costs.[55] To account for the changes in fuel cost between 2006 and 2007, the 2007 load-weighted LMP was adjusted to reflect the change in the daily price of fuels used by marginal units and the change in the amount of load affected by marginal units, using sensitivity factors.[56]

Before 2006, fuel-cost-adjusted LMP was calculated using monthly average fuel costs and an index number approach. The use of daily fuel prices and sensitivity factors for each marginal unit permits a more accurate adjustment and allows analysis for any aggregation of buses, e.g., zones.

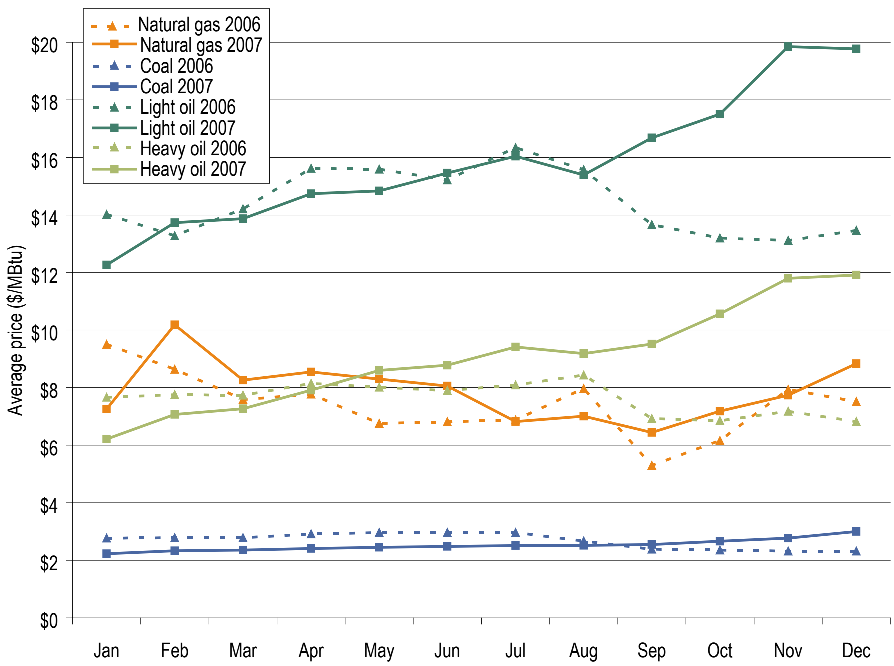
The dominant fuels in PJM, coal declined in price in 2007 and natural gas increased in price in 2007. In 2007, coal prices were 5.9 percent lower than in 2006. Natural gas prices were 6.4 percent higher in 2007 than in 2006. No. 2 (light) oil prices were 9.7 percent higher and No. 6 (heavy) oil prices were 18.4 percent higher in 2007 than in 2006.

55 See the *2007 State of the Market Report,* Volume II, Section 2,"Energy Market, Part 1," at Table 2-32, "Type of fuel used (By marginal units): Calendar years 2005 to 2007."

56 For more information, see the *2007 State of the Market Report,* Volume II, Appendix K, "Calculation and Use of Generator Sensitivity Factors."

Since September 2007, the prices for light oil and heavy oil had been much higher than those during the corresponding period in 2006. From September to December in 2007, coal prices were 17.1 percent higher, natural gas prices were 12.3 percent higher, No. 2 (light) oil prices were 38.2 percent and No. 6 (heavy) oil prices were 57.8 percent higher than the corresponding fuel prices during the same months in 2006. Figure 2-14 shows average, daily delivered coal, natural gas and oil prices for units within PJM.[57]

Figure 2-14 Spot average fuel price comparison: Calendar years 2006 to 2007



57 Natural gas prices are the daily cash price for Transco-Z6 (non-New York) adjusted for transportation to the burner tip. Light oil prices are the average of the daily price for No. 2 from the New York Harbor Spot Barge and from the Chicago pipeline and are adjusted for transportation. Heavy oil prices are a daily average of New York Harbor Spot Barge for 0.3 percent, 0.7 percent, 1.0 percent, 2.2 percent and 3.0 percent sulfur content. Coal prices are the 1.5 percent sulfur content per MBtu Central Appalachian coal, price-adjusted for transportation. All fuel prices are from Platts.

Figure 2-15 shows average, daily settled prices for NO_x and SO_2 emission within PJM. In 2007, NO_x prices were 56.5 percent lower than in 2006. SO_2 prices were 28.6 percent lower in 2007 than in 2006.

Figure 2-15 Spot average emission price comparison: Calendar years 2006 to 2007

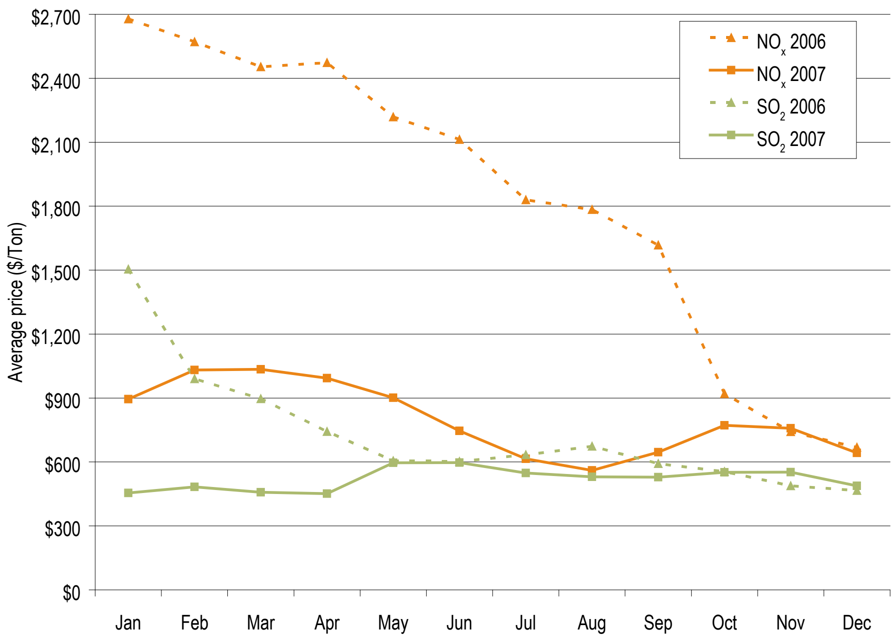


Table 2-55 compares the 2007 PJM fuel-cost-adjusted, load-weighted, average LMP to the 2006 load-weighted, average LMP. The load-weighted, average LMP for 2007 was 15.6 percent higher than the load-weighted, average LMP for 2006. The fuel-cost-adjusted, load-weighted, average LMP in 2007 was 18.1 percent higher than the load-weighted LMP in 2006. If fuel costs for the year 2007 had been the same as for 2006, the 2007 load-weighted LMP would have been higher, $63.00 per MWh instead of $61.66 per MWh. Lower coal prices in 2007 resulted in lower prices in 2007 than would have occurred if coal prices had remained the same, offset in part by higher prices for natural gas and oil. Net fuel-cost increases were a part (16.13 percent) of the reason for higher LMP in 2007, but prices would have been higher in 2007 even if fuel costs had remained at 2006 levels.

Table 2-55 PJM annual, fuel-cost-adjusted, load-weighted LMP (Dollars per MWh): Year-over-year method

	2006 Load-Weighted LMP	2007 Fuel-Cost-Adjusted, Load-Weighted LMP	Change
Average	$53.35	$63.00	18.1%
Median	$44.40	$54.55	22.9%
Standard deviation	$37.81	$35.36	(6.5%)

Table 2-56 compares the 2007 PJM fuel-cost-adjusted, load-weighted, average LMP to the 2006 load-weighted, average LMP on a monthly basis.

Table 2-56 PJM monthly, fuel-cost-adjusted, load-weighted LMP (Dollars per MWh): Year-over-year method

	2006 Load-Weighted LMP	2007 Fuel-Cost-Adjusted, Load-Weighted LMP	Change
Jan	$53.86	$60.10	11.6%
Feb	$54.21	$79.02	45.8%
Mar	$55.23	$63.82	15.6%
Apr	$49.34	$64.44	30.6%
May	$49.74	$56.84	14.3%
Jun	$48.22	$62.92	30.5%
Jul	$68.51	$69.12	0.9%
Aug	$81.28	$85.52	5.2%
Sep	$36.43	$55.60	52.6%
Oct	$41.83	$51.08	22.1%
Nov	$47.43	$49.50	4.4%
Dec	$42.20	$51.36	21.7%

Table 2-57 compares the 2007 PJM fuel-cost-adjusted, load-weighted, average LMP to the 2006 load-weighted, average LMP on a zonal basis.

Table 2-57 Zonal fuel-cost-adjusted, load-weighted LMP (Dollars per MWh): Calendar year 2007

	2006 Load-Weighted LMP	2007 Fuel-Cost-Adjusted, Load-Weighted LMP	Change
AECO	$62.32	$71.87	15.3%
AEP	$44.85	$52.00	15.9%
AP	$52.06	$62.34	19.7%
BGE	$63.54	$76.48	20.4%
ComEd	$45.05	$51.76	14.9%
DAY	$44.28	$52.56	18.7%
DLCO	$42.31	$49.59	17.2%
Dominion	$62.27	$73.42	17.9%
DPL	$58.28	$69.98	20.1%
JCPL	$58.12	$72.04	23.9%
Met-Ed	$57.18	$69.99	22.4%
PECO	$57.03	$67.37	18.1%
PENELEC	$49.13	$59.07	20.2%
Pepco	$65.57	$77.21	17.7%
PPL	$55.49	$66.74	20.3%
PSEG	$59.73	$70.49	18.0%
RECO	$59.79	$70.92	18.6%

Table 2-58 compares the PJM fuel-cost-adjusted, load-weighted, average LMP in 2007 to the 2006 load-weighted, average LMP based on jurisdiction.

Table 2-58 Jurisdiction fuel-cost-adjusted, load-weighted LMP (Dollars per MWh): Calendar year 2007

	2006 Load-Weighted LMP	2007 Fuel-Cost-Adjusted, Load-Weighted LMP	Change
Delaware	$57.49	$68.84	19.7%
Illinois	$45.05	$51.76	14.9%
Indiana	$43.99	$51.29	16.6%
Kentucky	$45.40	$52.98	16.7%
Maryland	$64.05	$76.58	19.6%
Michigan	$44.78	$52.53	17.3%
New Jersey	$59.62	$71.13	19.3%
North Carolina	$59.06	$69.54	17.7%
Ohio	$43.77	$51.27	17.1%
Pennsylvania	$53.05	$63.48	19.7%
Tennessee	$47.82	$52.47	9.7%
Virginia	$60.18	$70.33	16.9%
West Virginia	$44.72	$53.64	19.9%
District of Columbia	$64.37	$75.75	17.7%

Components of Real-Time, Load-Weighted LMP

Observed LMPs result from the operation of a market based on security-constrained, least-cost dispatch in which marginal units generally determine system LMPs, based on their offers. Those offers can be decomposed into fuel costs, emission costs, variable operation and maintenance costs and markup. As a result, it is possible to decompose PJM system LMP using the components of unit offers and sensitivity factors.

Spot fuel prices were used and emission costs were calculated using spot prices for NO_x and SO_2 emission credits and unit-specific emission rates. The emission costs for NO_x are applicable for the May-to-September ozone season and the emission costs for SO_2 are applicable throughout the year.

Table 2-59 shows that 35.0 percent of the annual, load-weighted LMP was the result of coal costs; 28.4 percent was the result of gas costs and 7.0 percent was the result of the cost of SO_2 emission allowances. Fuel costs, overall, accounted for 82.3 percent of marginal cost and for 69.8 percent of LMP.

In some cases, the bus price for the marginal unit may not equal the calculated price based on the offer curve of the marginal unit. These differences are the result of unit dispatch constraints and transmission constraints and the interactions among them. Any difference between the price based on the offer curve and the actual bus price for marginal units is defined as the “constrained off” component. In addition, final LMPs calculated using sensitivity factors may differ slightly from PJM’s posted LMPs as a result of rounding and missing data. This differential is identified as “NA” in Table 2-59.

Table 2-59 Components of PJM annual, load-weighted, average LMP: Calendar year 2007

Element	Contribution to LMP	Percent
Coal	$21.57	35.0%
Gas	$17.50	28.4%
Oil	$3.97	6.4%
Wind	$0.01	0.0%
SO_2	$4.33	7.0%
VOM	$4.16	6.7%
Markup	$5.86	9.5%
Constrained off	$3.13	5.1%
NO_x	$0.74	1.2%
NA	$0.39	0.6%

Day-Ahead LMP

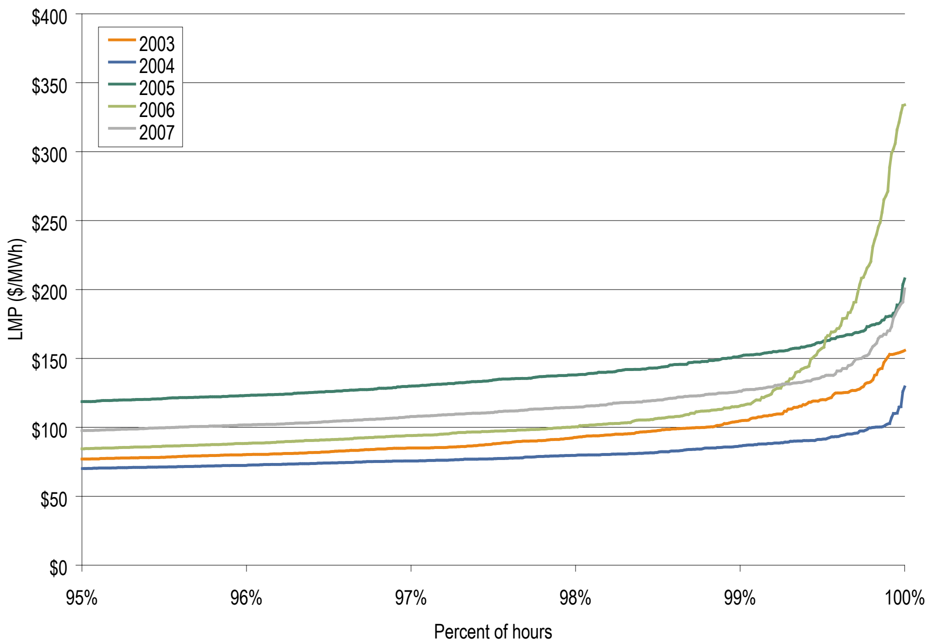
Day-ahead LMP is the hourly LMP for the PJM Day-Ahead Energy Market.

Day-Ahead Average LMP

PJM Day-Ahead LMP Duration

A price duration curve shows the percent of hours when LMP is at, or below, a given price for the year. Figure 2-16 presents day-ahead price duration curves for hours above the 95th percentile from 2003 to 2007. As Figure 2-16 shows, day-ahead LMP was less than $100 per MWh during 95 percent or more of the hours for the years 2003, 2004, 2006 and 2007 and less than $150 during 95 percent or more of the hours for 2005.

Figure 2-16 Price duration curves for the PJM Day-Ahead Energy Market during hours above the 95th percentile: Calendar years 2003 to 2007



PJM Day-Ahead, Annual Average LMP

Table 2-60 shows the PJM day-ahead annual, simple average LMP for the five-year period 2003 to 2007. The system simple average LMP for 2007 was 13.7 percent higher than the 2006 annual average, $54.67 per MWh versus $48.10 per MWh.

Table 2-60 PJM day-ahead, simple average LMP (Dollars per MWh): Calendar years 2003 to 2007

	Day-Ahead LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2003	$38.72	$35.21	$20.84	NA	NA	NA
2004	$41.43	$40.36	$16.60	7.0%	14.6%	(20.3%)
2005	$57.89	$50.08	$30.04	39.7%	24.1%	81.0%
2006	$48.10	$44.21	$23.42	(16.9%)	(11.7%)	(22.0%)
2007	$54.67	$52.34	$23.99	13.7%	18.4%	2.4%

Zonal Day-Ahead, Annual Average LMP

Table 2-61 shows PJM zonal day-ahead, simple average LMP for 2006 and 2007. The largest zonal increase was in the JCPL Control Zone which experienced an $11.95 increase over 2006 and the smallest increase was in the AEP Control Zone which experienced a $4.15 increase over 2006.

Table 2-61 Zonal day-ahead, simple average LMP (Dollars per MWh): Calendar years 2006 to 2007

	2006	2007	Difference	Difference as Percent of 2006
AECO	$54.58	$62.96	$8.38	15.4%
AEP	$41.40	$45.55	$4.15	10.0%
AP	$47.33	$54.88	$7.55	16.0%
BGE	$55.51	$65.37	$9.86	17.8%
ComEd	$41.04	$45.35	$4.31	10.5%
DAY	$40.33	$45.29	$4.96	12.3%
DLCO	$38.96	$43.75	$4.79	12.3%
Dominion	$54.58	$63.42	$8.84	16.2%
DPL	$52.99	$61.95	$8.96	16.9%
JCPL	$51.23	$63.18	$11.95	23.3%
Met-Ed	$52.64	$61.62	$8.98	17.1%
PECO	$52.46	$61.25	$8.79	16.8%
PENELEC	$46.08	$52.97	$6.89	15.0%
Pepco	$56.78	$66.44	$9.66	17.0%
PPL	$51.48	$60.00	$8.52	16.6%
PSEG	$53.68	$63.94	$10.26	19.1%
RECO	$53.63	$63.37	$9.74	18.2%

Day-Ahead, Annual Average LMP by Jurisdiction

Table 2-62 shows PJM's day-ahead, simple average LMPs for 2006 and 2007, by jurisdiction. The largest increase was in New Jersey which experienced a $10.47 increase over 2006, and the smallest increase was in Tennessee which experienced a $2.84 increase over 2006.

Table 2-62 Jurisdiction day-ahead, simple average LMP (Dollars per MWh): Calendar years 2006 to 2007

	2006	2007	Difference	Difference as Percent of 2006
Delaware	$52.72	$61.40	$8.68	16.5%
Illinois	$41.04	$45.34	$4.30	10.5%
Indiana	$40.74	$45.47	$4.73	11.6%
Kentucky	$41.43	$45.40	$3.97	9.6%
Maryland	$55.79	$65.64	$9.85	17.7%
Michigan	$40.80	$46.00	$5.20	12.7%
New Jersey	$53.12	$63.59	$10.47	19.7%
North Carolina	$52.56	$59.83	$7.27	13.8%
Ohio	$40.03	$44.71	$4.68	11.7%
Pennsylvania	$49.03	$56.84	$7.81	15.9%
Tennessee	$43.68	$46.52	$2.84	6.5%
Virginia	$53.44	$61.01	$7.57	14.2%
West Virginia	$41.33	$46.54	$5.21	12.6%
District of Columbia	$56.54	$66.40	$9.86	17.4%

Day-Ahead, Load-Weighted, Average LMP

Day-ahead, load-weighted LMP reflects the average LMP paid for day-ahead demand MWh cleared during a year. Day-ahead, load-weighted LMP is the average of PJM day-ahead hourly LMPs, each weighted by the PJM total cleared day-ahead hourly load, including day-ahead fixed load, price-sensitive load and decrement bids.

PJM Day-Ahead, Annual, Load-Weighted, Average LMP

Table 2-63 shows the PJM day-ahead, annual, load-weighted, average LMP for the five-year period 2003 to 2007. The day-ahead, load-weighted, average LMP for 2007 was 12.8 percent higher than the 2006 annual, load-weighted, average, at $57.88 per MWh versus $51.33 per MWh.

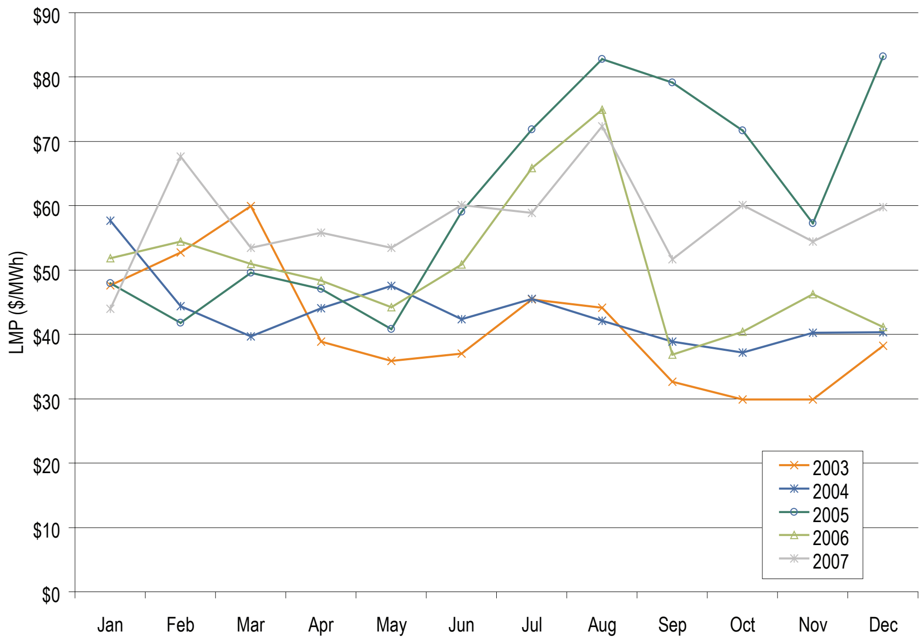
Table 2-63 PJM day-ahead, load-weighted, average LMP (Dollars per MWh): Calendar years 2003 to 2007

	Day-Ahead, Load-Weighted, Average LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2003	$41.42	$38.29	$21.32	NA	NA	NA
2004	$42.87	$41.96	$16.32	3.5%	9.6%	(23.5%)
2005	$62.50	$54.74	$31.72	45.8%	30.5%	94.4%
2006	$51.33	$46.72	$26.45	(17.9%)	(14.7%)	(16.6%)
2007	$57.88	$55.91	$25.02	12.8%	19.7%	(5.4%)

PJM Day-Ahead, Monthly, Load-Weighted, Average LMP

Figure 2-17 shows the PJM day-ahead, monthly, load-weighted LMP from 2003 through 2007.

Figure 2-17 Day-ahead, monthly, load-weighted, average LMP: Calendar years 2003 to 2007



Zonal Day-Ahead, Annual, Load-Weighted LMP

Table 2-64 shows PJM's zonal day-ahead, load-weighted, average LMPs for 2006 and 2007. The largest zonal increase was in the JCPL Control Zone which experienced an $11.32 increase over 2006, and the smallest increase was in the ComEd Control Zone which experienced a $3.93 increase over 2006.

Table 2-64 Zonal day-ahead, load-weighted, average LMP (Dollars per MWh): Calendar years 2006 to 2007

	2006	2007	Difference	Difference as Percent of 2006
AECO	$61.73	$69.11	$7.38	12.0%
AEP	$43.68	$48.26	$4.58	10.5%
AP	$49.58	$57.34	$7.76	15.7%
BGE	$61.00	$70.22	$9.22	15.1%
ComEd	$43.34	$47.27	$3.93	9.1%
DAY	$43.02	$48.43	$5.41	12.6%
DLCO	$41.64	$46.99	$5.35	12.8%
Dominion	$59.57	$68.08	$8.51	14.3%
DPL	$58.57	$66.84	$8.27	14.1%
JCPL	$57.02	$68.34	$11.32	19.9%
Met-Ed	$57.51	$65.36	$7.85	13.6%
PECO	$56.46	$65.21	$8.75	15.5%
PENELEC	$47.61	$55.44	$7.83	16.4%
Pepco	$60.64	$70.50	$9.86	16.3%
PPL	$55.00	$63.52	$8.52	15.5%
PSEG	$57.96	$68.01	$10.05	17.3%
RECO	$59.23	$68.88	$9.65	16.3%

Day-Ahead, Annual, Load-Weighted, Average LMP by Jurisdiction

Table 2-65 shows PJM's day-ahead, load-weighted, average LMPs for 2006 and 2007 by jurisdiction. The largest increase was in the District of Columbia which experienced a $10.25 increase over 2006, and the smallest increase was in Tennessee which experienced a $3.39 increase over 2006.

Table 2-65 Jurisdiction day-ahead, load-weighted LMP (Dollars per MWh): Calendar years 2006 to 2007

	2006	2007	Difference	Difference as Percent of 2006
Delaware	$57.98	$66.03	$8.05	13.9%
Illinois	$43.34	$47.26	$3.92	9.0%
Indiana	$43.15	$48.24	$5.09	11.8%
Kentucky	$43.52	$48.07	$4.55	10.5%
Maryland	$60.51	$70.21	$9.70	16.0%
Michigan	$43.48	$48.72	$5.24	12.1%
New Jersey	$58.20	$68.21	$10.01	17.2%
North Carolina	$57.38	$65.04	$7.66	13.3%
Ohio	$42.36	$47.41	$5.05	11.9%
Pennsylvania	$52.03	$60.06	$8.03	15.4%
Tennessee	$45.93	$49.32	$3.39	7.4%
Virginia	$57.92	$65.32	$7.40	12.8%
West Virginia	$43.43	$49.20	$5.77	13.3%
District of Columbia	$59.82	$70.07	$10.25	17.1%

Marginal Losses

Marginal losses are the incremental change in system real power losses caused by changes in the system load and generation patterns.[58] Before June 1, 2007, the PJM economic dispatch and LMP models did not include marginal losses. The losses were treated as a static component of load, and the physical nature and location of power system losses were ignored. The PJM Tariff required implementation of marginal loss modeling when required technical systems became available. On June 1, 2007, PJM began including marginal losses in economic dispatch and LMP models.[59] The primary benefit of a marginal loss mechanism is that it more accurately models the physical reality of power system losses. More accurate models permit increased efficiency and optimize asset utilization. One characteristic of marginal loss modeling is that it creates a separate marginal loss price for every location on the power grid.

Table 2-66 shows the PJM real-time, simple average LMP components, including the loss component, for calendar years 2006 and 2007. Effective June 1, 2007, PJM changed from a single node reference bus to a distributed load reference bus. While there is no effect on the total LMP, the components of LMP change

58 For additional information, see the *2007 State of the Market Report*, Volume II, Appendix J, "Marginal Losses."

59 For additional information, see PJM. "Open Access Transmission Tariff" (December 10, 2007), Section 3.4, Original Sheet No. 388G.

with a shift in the reference bus. With a distributed load reference bus, the energy component is now a load-weighted system price. In turn, this means that there is no congestion or losses included at the PJM price, unlike the case with a single node reference bus. The energy price equals the PJM price in a given hour and on a yearly average basis. Table 2-66 shows a $0.02 loss component included at the PJM price. The PJM price is weighted with accounting load, which differs from the state-estimated load used in determination of the energy component. The $0.02 loss component of the average PJM system price results from these different weights. The $1.00 congestion component of the average PJM system price results from the fact that the average is calculated over the entire calendar year, but only six months included a distributed load reference bus.

Table 2-66 PJM real-time, simple average LMP components (Dollars per MWh): Calendar years 2006 and 2007

	Real-Time LMP	Energy Component	Congestion Component	Loss Component
2006	$49.27	$47.19	$2.08	$0.00
2007	$57.58	$56.56	$1.00	$0.02

Table 2-67 shows the zonal real-time, simple average LMP components, including the loss component, for calendar years 2006 and 2007.

Table 2-67 Zonal real-time, simple average LMP components (Dollars per MWh): Calendar years 2006 and 2007.

	2006				2007			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AECO	$55.53	$47.19	$8.34	$0.0	$65.02	$56.56	$6.42	$2.04
AEP	$42.24	$47.19	($4.95)	$0.0	$46.55	$56.56	($8.80)	($1.21)
AP	$48.71	$47.19	$1.52	$0.0	$57.45	$56.56	$1.33	($0.44)
BGE	$57.40	$47.19	$10.21	$0.0	$69.79	$56.56	$12.08	$1.15
ComEd	$41.52	$47.19	($5.67)	$0.0	$45.71	$56.56	($9.42)	($1.43)
DAY	$41.21	$47.19	($5.98)	$0.0	$46.47	$56.56	($9.54)	($0.55)
Dominion	$56.44	$47.19	$9.25	$0.0	$66.75	$56.56	$9.89	$0.30
DPL	$53.09	$47.19	$5.90	$0.0	$64.15	$56.56	$6.09	$1.50
DLCO	$39.34	$47.19	($7.85)	$0.0	$43.93	$56.56	($11.13)	($1.50)
JCPL	$51.80	$47.19	$4.61	$0.0	$65.74	$56.56	$7.36	$1.82
Met-Ed	$52.66	$47.19	$5.47	$0.0	$64.57	$56.56	$7.32	$0.69
PECO	$52.40	$47.19	$5.21	$0.0	$62.60	$56.56	$4.82	$1.22
PENELEC	$46.64	$47.19	($0.55)	$0.0	$54.80	$56.56	($1.46)	($0.30)
Pepco	$58.85	$47.19	$11.66	$0.0	$70.33	$56.56	$13.00	$0.77
PPL	$51.52	$47.19	$4.33	$0.0	$62.02	$56.56	$4.89	$0.57
PSEG	$54.57	$47.19	$7.38	$0.0	$65.92	$56.56	$7.43	$1.93
RECO	$53.88	$47.19	$6.69	$0.0	$64.85	$56.56	$6.50	$1.79

Table 2-68 shows the real-time, annual, simple average LMP components from June 1, 2007, to December 31, 2007, for each zone and PJM.

Table 2-68 Zonal and PJM real-time, simple average LMP components (Dollars per MWh): June 1, 2007, to December 31, 2007

	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AECO	$69.18	$59.49	$6.21	$3.48
AEP	$47.28	$59.49	($10.16)	($2.06)
AP	$58.50	$59.49	($0.25)	($0.75)
BGE	$73.14	$59.49	$11.69	$1.96
ComEd	$46.00	$59.49	($11.05)	($2.45)
DAY	$47.32	$59.49	($11.24)	($0.93)
DLCO	$42.85	$59.49	($14.08)	($2.56)
Dominion	$69.73	$59.49	$9.72	$0.51
DPL	$67.09	$59.49	$5.04	$2.56
JCPL	$70.13	$59.49	$7.53	$3.10
Met-Ed	$67.42	$59.49	$6.75	$1.18
PECO	$65.04	$59.49	$3.47	$2.08
PENELEC	$56.22	$59.49	($2.75)	($0.52)
Pepco	$73.30	$59.49	$12.50	$1.31
PPL	$64.49	$59.49	$4.03	$0.97
PSEG	$68.68	$59.49	$5.89	$3.30
RECO	$67.97	$59.49	$5.43	$3.05
PJM	$59.56	$59.49	$0.02	$0.04

Table 2-69 shows the real-time, annual, simple average LMP loss component at the PJM hubs from June 1, 2007, to December 31, 2007, for each hub in PJM.

Table 2-69 Hub real-time, simple average LMP components (Dollars per MWh): June 1, 2007, to December 31, 2007

	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AEP Gen Hub	$43.58	$59.49	($11.70)	($4.21)
AEP-DAY Hub	$46.82	$59.49	($10.56)	($2.11)
Chicago Gen Hub	$44.97	$59.49	($11.19)	($3.34)
Chicago Hub	$46.07	$59.49	($11.00)	($2.43)
Dominion Hub	$67.47	$59.49	$8.04	($0.06)
Eastern Hub	$66.97	$59.49	$4.51	$2.97
N Illinois Hub	$45.57	$59.49	($11.06)	($2.86)
New Jersey Hub	$69.03	$59.49	$6.32	$3.21
Ohio Hub	$46.72	$59.49	($10.91)	($1.86)
West Interface Hub	$52.33	$59.49	($4.92)	($2.24)
Western Hub	$60.93	$59.49	$2.20	($0.77)

Zonal and PJM Real-Time, Annual, Load-Weighted, Average LMP Components

Table 2-70 shows the real-time, annual, load-weighted, average LMP components for PJM and its 17 control zones from June 1, 2007, to December 31, 2007.

Table 2-70 Zonal and PJM real-time, annual, load-weighted, average LMP components (Dollars per MWh): June 1, 2007, to December 31, 2007

	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AECO	$77.22	$65.41	$7.92	$3.88
AEP	$50.66	$63.35	($10.53)	($2.16)
AP	$62.81	$63.94	($0.33)	($0.81)
BGE	$80.48	$64.77	$13.50	$2.20
ComEd	$50.28	$63.81	($11.11)	($2.42)
DAY	$51.39	$64.06	($11.78)	($0.89)
DLCO	$46.85	$63.95	($14.38)	($2.71)
Dominion	$76.54	$64.96	$10.99	$0.59
DPL	$73.10	$65.03	$5.25	$2.82
JCPL	$77.64	$66.16	$8.15	$3.33
Met-Ed	$73.11	$64.37	$7.54	$1.20
PECO	$70.39	$64.55	$3.64	$2.20
PENELEC	$59.55	$63.17	($3.05)	($0.57)
Pepco	$80.85	$64.85	$14.52	$1.47
PPL	$69.31	$64.04	$4.27	$1.01
PSEG	$74.47	$64.84	$6.16	$3.48
RECO	$74.66	$66.05	$5.37	$3.24
PJM	$64.38	$64.31	$0.02	$0.05

Table 2-71 shows the PJM day-ahead, simple average LMP components, including the loss component, for calendar years 2006 and 2007. Effective June 1, 2007, in the Day-Ahead Energy Market, the distributed load reference bus is weighted with fixed-demand bids only and the day-ahead energy component is, therefore, a system fixed-demand-weighted price. The day-ahead system price calculation uses all types of demand, including fixed, price-sensitive and decrement bids. In the Real-Time Energy Market, the energy component equals the system load-weighted price; however, in the Day-Ahead Energy Market the energy component and the PJM system price are not equal, but the loss component and the congestion component have only a small effect. This is due to the use of all types of demand to weight the PJM price and not fixed demand only.

Table 2-71 PJM day-ahead, simple average LMP components (Dollars per MWh): Calendar years 2006 and 2007

	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
2006	$48.10	$46.45	$1.65	$0.00
2007	$54.67	$54.60	$0.25	($0.18)

Table 2-72 shows the zonal day-ahead, simple average LMP components, including the loss component, for calendar years 2006 and 2007.

Table 2-72 Zonal day-ahead, simple average LMP components (Dollars per MWh): Calendar years 2006 and 2007

	2006				2007			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AECO	$54.58	$46.45	$8.13	$0.0	$62.96	$54.60	$6.27	$2.09
AEP	$41.40	$46.45	($5.06)	$0.0	$45.55	$54.60	($7.59)	($1.46)
AP	$47.33	$46.45	$0.88	$0.0	$54.88	$54.60	$0.77	($0.49)
BGE	$55.51	$46.45	$9.06	$0.0	$65.37	$54.60	$9.50	$1.27
ComEd	$41.04	$46.45	($5.41)	$0.0	$45.35	$54.60	($7.80)	($1.45)
DAY	$40.33	$46.45	($6.12)	$0.0	$45.29	$54.60	($8.12)	($1.19)
DLCO	$38.96	$46.45	($7.49)	$0.0	$43.75	$54.60	($9.22)	($1.64)
DPL	$52.99	$46.45	$6.54	$0.0	$61.95	$54.60	$5.72	$1.63
Dominion	$54.58	$46.45	$8.13	$0.0	$63.42	$54.60	$8.42	$0.39
JCPL	$51.23	$46.45	$4.78	$0.0	$63.18	$54.60	$6.49	$2.09
Met-Ed	$52.64	$46.45	$6.19	$0.0	$61.62	$54.60	$6.24	$0.77
PECO	$52.46	$46.45	$6.01	$0.0	$61.25	$54.60	$5.01	$1.63
PENELEC	$46.08	$46.45	($0.37)	$0.0	$52.97	$54.60	($1.14)	($0.50)
Pepco	$56.78	$46.45	$10.33	$0.0	$66.44	$54.60	$10.83	$1.00
PPL	$51.48	$46.45	$5.03	$0.0	$60.00	$54.60	$4.75	$0.65
PSEG	$53.68	$46.45	$7.23	$0.0	$63.94	$54.60	$7.05	$2.29
RECO	$53.63	$46.45	$7.18	$0.0	$63.37	$54.60	$6.77	$2.00

Table 2-73 shows day-ahead, annual average LMP components from June 1, 2007, to December 31, 2007, for each zone and for PJM.

Table 2-73 Zonal and PJM day-ahead, simple average LMP components (Dollars per MWh): June 1, 2007, to December 31, 2007

	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AECO	$66.21	$56.97	$5.69	$3.56
AEP	$46.09	$56.97	($8.39)	($2.49)
AP	$55.73	$56.97	($0.40)	($0.84)
BGE	$68.51	$56.97	$9.38	$2.17
ComEd	$45.70	$56.97	($8.79)	($2.48)
DAY	$45.84	$56.97	($9.10)	($2.03)
DLCO	$42.83	$56.97	($11.34)	($2.79)
Dominion	$66.04	$56.97	$8.41	$0.67
DPL	$64.24	$56.97	$4.50	$2.78
JCPL	$66.81	$56.97	$6.28	$3.57
Met-Ed	$63.98	$56.97	$5.70	$1.32
PECO	$63.39	$56.97	$3.64	$2.79
PENELEC	$54.29	$56.97	($1.82)	($0.85)
Pepco	$69.53	$56.97	$10.86	$1.70
PPL	$61.95	$56.97	$3.88	$1.10
PSEG	$66.76	$56.97	$5.89	$3.90
RECO	$66.14	$56.97	$5.76	$3.41
PJM	$56.20	$56.97	($0.46)	($0.31)

Zonal and PJM Day-Ahead, Annual, Load-Weighted, Average LMP Components

Table 2-74 shows zonal and PJM day-ahead, annual, load-weighted, average LMP components from June 1, 2007, to December 31, 2007.

Table 2-74 Zonal and PJM day-ahead, load-weighted, average LMP components (Dollars per MWh): June 1, 2007, to December 31, 2007

	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AECO	$73.66	$62.65	$7.05	$3.97
AEP	$49.19	$60.46	($8.65)	($2.62)
AP	$58.29	$59.65	($0.48)	($0.89)
BGE	$74.33	$61.60	$10.31	$2.42
ComEd	$48.15	$59.61	($9.00)	($2.46)
DAY	$49.32	$60.84	($9.42)	($2.10)
DLCO	$46.76	$61.64	($11.91)	($2.98)
Dominion	$71.43	$61.70	$9.02	$0.72
DPL	$70.03	$62.33	$4.68	$3.02
JCPL	$73.22	$62.70	$6.76	$3.76
Met-Ed	$68.57	$61.07	$6.19	$1.30
PECO	$68.14	$61.42	$3.76	$2.95
PENELEC	$57.10	$60.01	($2.01)	($0.90)
Pepco	$74.45	$60.81	$11.78	$1.87
PPL	$66.06	$60.90	$4.04	$1.12
PSEG	$71.64	$61.62	$5.96	$4.06
RECO	$72.15	$62.99	$5.61	$3.54
PJM	$60.01	$60.80	($0.47)	($0.33)

Marginal Loss Accounting

With the implementation of marginal loss pricing, PJM calculates transmission loss charges for each PJM member. The loss charge is based on the applicable day-ahead and real-time loss component of LMP (loss LMP). Each PJM member is charged for the cost of losses on the transmission system, based on the difference between the loss LMP at the location where the PJM member injects energy and the loss LMP where the PJM member withdraws energy.

More specifically, total loss charges are equal to the load loss payments minus generation loss credits, plus explicit loss charges, incurred in both the Day-Ahead Energy Market and the balancing energy market.

- Day-Ahead, Load Loss Payments. Day-ahead, load loss payments are calculated for all cleared demand, decrement bids and Day-Ahead Energy Market sale transactions. (Decrement bids and energy sales can be thought of as scheduled load.) Day-ahead, load loss payments are calculated using MW and the load bus loss component of LMP (loss LMP), the decrement bid loss LMP or the loss LMP at the source of the sale transaction, as applicable.

- Day-Ahead, Generation Loss Credits. Day-ahead, generation loss credits are calculated for all cleared generation and increment offers and Day-Ahead Energy Market purchase transactions. (Increment offers and energy purchases can be thought of as scheduled generation.) Day-ahead, generation loss credits are calculated using MW and the generator bus loss LMP, the increment offer loss LMP or the loss LMP at the sink of the purchase transaction, as applicable.

- Balancing, Load Loss Payments. Balancing, load loss payments are calculated for all deviations between a PJM member's real-time load and energy sale transactions and their day-ahead cleared demand, decrement bids and energy sale transactions. Balancing, load loss payments are calculated using MW deviations and the real-time loss LMP for each bus where a deviation exists.

- Balancing, Generation, Loss Credits. Balancing, generation loss credits are calculated for all deviations between a PJM member's real-time generation and energy purchase transactions and the day-ahead cleared generation, increment offers and energy purchase transactions. Balancing generation loss credits are calculated using MW deviations and the real-time loss LMP for each bus where a deviation exists.

- Explicit Loss Charges. Explicit loss charges are the net loss charges associated with point-to-point energy transactions. These charges equal the product of the transacted MW and loss LMP differences between sources (origins) and sinks (destinations) in the Day-Ahead Energy Market. Balancing energy market explicit loss charges equal the product of the differences between the real-time and day-ahead transacted MW and the differences between the real-time loss LMP at the transactions' sources and sinks.

Monthly Marginal Loss Costs

Table 2-75 shows a monthly summary of marginal loss costs by type. Marginal loss costs totaled $1.247 billion. The highest monthly loss cost was in August and totaled $247.7 million or 19.8 percent of the total. The majority of the marginal loss costs was in the Day-Ahead Energy Market and totaled $1.261 billion. The day-ahead costs were offset, in part, by a total of -$14.1 million in the balancing market. The overcollected portion of transmission losses that was credited back to load plus exports as of December 31, 2007, was $630 million or 50.5 percent of the total losses. In determining the overcollected loss amount, PJM accumulates the day-ahead and balancing transmission loss charges paid by all customer accounts each hour, subtracts the spot market energy value of the actual transmission loss MWh during that hour, and allocates this amount as transmission loss credits each hour.[60]

60 See PJM. "Manual 28: Operating Agreement Accounting," Revision 39 (January 1, 2008). Note that the overcollection is not calculated by subtracting the prior calculation of average losses from the calculated total marginal losses.

Table 2-75 Marginal loss costs by type (Dollars (Millions)): June 1, 2007, to December 31, 2007

	Marginal Loss Costs (Millions)								
	Day Ahead				Balancing				
	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total
Jun	($30.7)	($198.8)	$8.7	$176.8	$2.4	$0.0	($3.6)	($1.2)	$175.5
Jul	($33.7)	($216.3)	$6.9	$189.5	$0.9	($0.4)	($2.7)	($1.4)	$188.1
Aug	($45.8)	($287.4)	$8.0	$249.6	$8.4	$8.5	($1.8)	($1.9)	$247.7
Sep	($24.3)	($167.4)	$6.8	$149.9	($4.1)	($5.7)	($1.7)	($0.1)	$149.8
Oct	($21.2)	($169.7)	$8.6	$157.1	($5.7)	($6.0)	($2.1)	($1.8)	$155.4
Nov	($20.0)	($159.7)	$7.8	$147.5	($8.9)	($7.1)	($2.8)	($4.6)	$142.9
Dec	($23.8)	($203.7)	$10.7	$190.6	($12.8)	($13.4)	($3.6)	($3.0)	$187.6
Total	($199.7)	($1,403.1)	$57.6	$1,261.0	($19.8)	($24.1)	($18.3)	($14.1)	$1,246.9

Zonal Marginal Loss Costs

Table 2-76 shows the marginal loss costs by type in each control zone. The AEP, ComEd and Dominion control zones had the highest marginal loss costs in 2007, with $266.2 million, $211.4 million and $130.7 million, respectively. Energy flows in PJM are generally from west to east, reflecting the fact that less expensive generation in the western portion of PJM is dispatched to assist in meeting the demand of load centers located in the eastern portion of PJM. Generation supplied from western resources to satisfy eastern load generally results in increased west-to-east transmission flow and increased losses. As may be seen in Table 2-76, the marginal loss generation credits in the western zones are generally greater in magnitude and negative relative to those of the eastern zones. The characteristics of the marginal loss component of LMP are analogous to those of the congestion component of LMP, or CLMP. Generation congestion credits are generally negative for units located on the unconstrained side of a transmission element, indicating that an increase in output tends to increase the flow of energy across the constrained element. Analogously, the generation marginal loss credits are generally negative for units for which an increase in output tends to increase system losses.

Table 2-76 Marginal loss costs by control zone and type (Dollars (Millions)): June 1, 2007, to December 31, 2007

	Marginal Loss Costs by Control Zone (Millions)								
	Day Ahead				Balancing				
	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total
AECO	$28.1	$9.0	$0.4	$19.5	$29.2	$27.4	($0.3)	$1.5	$21.0
AEP	($284.9)	($556.2)	$9.6	$280.9	($184.5)	($168.7)	$1.0	($14.8)	$266.2
AP	($27.9)	($111.5)	$3.0	$86.5	($9.3)	($7.4)	($1.2)	($3.2)	$83.4
BGE	$56.9	$20.8	$1.9	$38.0	$46.8	$44.1	($1.6)	$1.0	$39.0
ComEd	($323.8)	($523.8)	$0.5	$200.6	($143.2)	($154.0)	$0.1	$10.9	$211.4
DAY	($28.1)	($73.0)	$1.4	$46.3	($10.6)	($7.5)	($0.0)	($3.1)	$43.1
DLCO	($64.2)	($86.6)	$0.0	$22.4	($28.9)	($22.7)	($0.0)	($6.2)	$16.1
DPL	$41.5	$13.3	$1.1	$29.2	$34.0	$32.0	($0.8)	$1.2	$30.4
Dominion	$35.1	($93.1)	$1.4	$129.6	$35.6	$33.9	($0.5)	$1.1	$130.7
JCPL	$65.6	$29.0	$0.7	$37.4	$54.6	$51.2	($0.6)	$2.8	$40.2
Met-Ed	$12.8	($0.6)	$1.1	$14.5	$0.8	($0.3)	$4.3	$5.4	$19.9
PECO	$154.7	$94.4	$0.3	$60.6	$3.0	$4.8	($0.2)	($1.9)	$58.7
PENELEC	($103.7)	($189.1)	$0.4	$85.8	$0.9	$1.9	$1.6	$0.6	$86.4
Pepco	$69.4	$34.6	$2.6	$37.4	$40.6	$39.1	($2.2)	($0.6)	$36.8
PJM	($10.1)	($10.6)	$25.5	$26.0	($1.4)	($7.4)	($13.8)	($7.9)	$18.2
PPL	$52.3	($10.0)	$1.4	$63.6	$4.4	$3.4	$0.5	$1.6	$65.2
PSEG	$123.5	$50.1	$6.1	$79.5	$104.8	$102.9	($4.7)	($2.8)	$76.8
RECO	$3.3	$0.1	$0.0	$3.2	$3.5	$3.1	($0.0)	$0.3	$3.5
Total	($199.7)	($1,403.1)	$57.6	$1,261.0	($19.8)	($24.1)	($18.3)	($14.1)	$1,246.9

Table 2-77 shows the monthly marginal loss cost, by control zone. With the exception of August, the marginal loss costs were distributed fairly evenly across all months.

Table 2-77 Monthly marginal loss costs by control zone (Dollars (Millions)): June 1, 2007, to December 31, 2007

Marginal Loss Costs by Control Zone (Millions)								
	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Grand Total
AECO	$3.3	$4.0	$4.3	$2.3	$2.5	$2.2	$2.5	$21.0
AEP	$36.4	$40.1	$57.2	$32.4	$33.0	$28.7	$38.4	$266.2
AP	$11.9	$11.7	$16.8	$10.0	$11.8	$8.9	$12.2	$83.4
BGE	$5.4	$6.2	$8.0	$4.7	$5.2	$4.3	$5.2	$39.0
ComEd	$29.4	$31.1	$42.9	$28.0	$27.2	$23.6	$29.1	$211.4
DAY	$5.9	$6.2	$9.2	$5.3	$5.3	$5.0	$6.2	$43.1
DLCO	$2.8	$2.6	$2.6	$1.6	$1.2	$2.4	$3.0	$16.1
DPL	$4.2	$4.8	$5.5	$3.3	$4.0	$3.6	$5.0	$30.4
Dominion	$20.0	$21.7	$28.8	$16.1	$15.4	$12.3	$16.5	$130.7
JCPL	$5.6	$6.4	$5.7	$4.7	$5.0	$5.0	$7.8	$40.2
Met-Ed	$2.7	$3.0	$4.3	$2.4	$2.7	$2.1	$2.6	$19.9
PECO	$8.6	$9.7	$12.5	$6.4	$6.0	$6.4	$9.0	$58.7
PENELEC	$13.0	$12.9	$17.7	$9.9	$9.6	$10.1	$13.3	$86.4
Pepco	$5.0	$6.0	$7.4	$5.1	$5.4	$3.4	$4.5	$36.8
PJM	$0.7	($0.6)	($1.5)	$0.5	$3.4	$6.2	$9.4	$18.2
PPL	$8.4	$9.8	$13.7	$7.5	$7.5	$8.6	$9.8	$65.2
PSEG	$11.6	$11.9	$12.3	$9.0	$9.8	$9.8	$12.3	$76.8
RECO	$0.5	$0.6	$0.4	$0.4	$0.5	$0.5	$0.7	$3.5
Total	$175.5	$188.1	$247.7	$149.8	$155.4	$142.9	$187.6	$1,246.9

Price Convergence

The PJM Day-Ahead Energy Market, introduced on June 1, 2000, includes the ability to make increment offers (INC) and decrement bids (DEC) at any hub, transmission zone, aggregate, or single bus for which LMP is calculated. Since increment offers and decrement bids do not require physical generation or load, they are also referred to as virtual offers and bids. When the PJM Day-Ahead Energy Market was introduced, it was expected that competition, exercised substantially through the use of virtual offers and bids, would cause prices in the Day-Ahead and Real-Time Energy Markets to converge. Virtual offers and bids also provide participants the flexibility, for example, to cover one side of a bilateral transaction, hedge day-ahead generator offers or demand bids, and arbitrage day-ahead and real-time prices.

There is a substantial volume of virtual offers and bids in the PJM Day-Ahead Market and such offers and bids may each be marginal, based on the way in which the optimization algorithm works.

Table 2-78 shows the frequency with which generation offers, import or export transactions, decrement bids, increment offers and price-sensitive demand are marginal for each month in 2007.[61] Together, increment offers and decrement bids represented 58.6 percent of the marginal bids or offers in 2007.

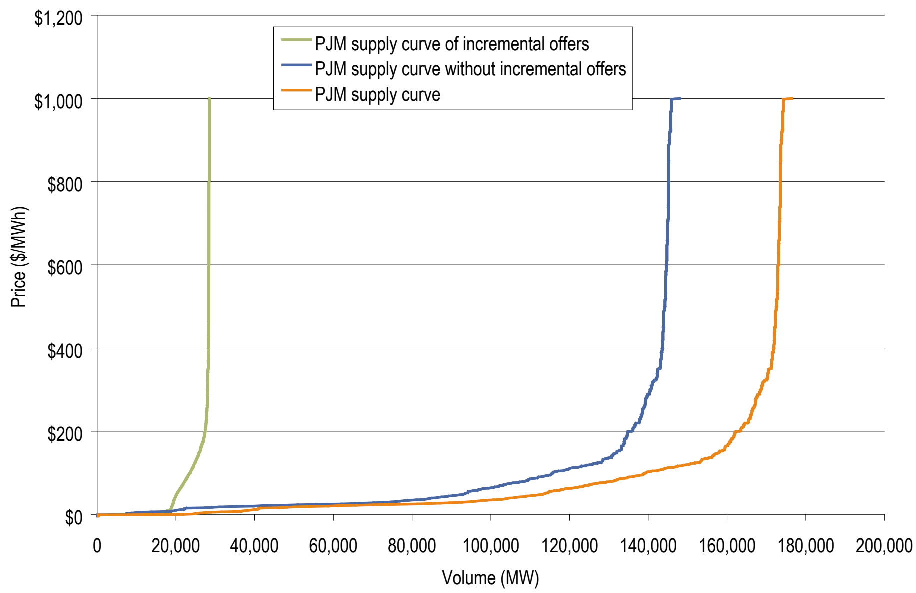
Table 2-78 Type of day-ahead marginal units: Calendar year 2007

	Generation	Transaction	Decrement Bid	Increment Offer	Price-Sensitive Demand
Jan	16.0%	29.2%	34.2%	19.9%	0.8%
Feb	10.4%	34.9%	33.1%	20.1%	1.4%
Mar	14.3%	35.4%	33.4%	16.0%	0.9%
Apr	11.5%	31.6%	37.9%	18.3%	0.7%
May	10.8%	38.5%	30.3%	19.9%	0.5%
Jun	14.6%	22.5%	40.8%	21.7%	0.4%
Jul	13.9%	20.9%	35.4%	29.1%	0.6%
Aug	11.0%	19.0%	41.4%	27.8%	0.7%
Sep	14.9%	27.5%	36.2%	20.6%	0.8%
Oct	14.6%	24.4%	40.7%	19.9%	0.5%
Nov	16.8%	24.0%	42.2%	16.5%	0.5%
Dec	14.5%	23.1%	45.5%	16.5%	0.4%
Annual	13.6%	27.1%	37.7%	20.9%	0.7%

61 These percentages compare the number of times that bids and offers of the specified type were marginal to the total number of marginal bids and offers. There is no weighting by time or by load.

Figure 2-18 shows the PJM day-ahead daily aggregate supply curve of increment offers, the system aggregate supply curve without increment offers and the system aggregate supply curve with increment offers for an example day in 2007. There were average hourly increment offers of 28,476 MW and average hourly total offers of 176,507 MW for the example day.

Figure 2-18 PJM day-ahead aggregate supply curves: 2007 example day



PJM Price Convergence

Although the introduction of PJM Day-Ahead Energy Market and virtual offers and bids was expected to cause prices in the Day-Ahead and Real-Time Energy Markets to converge, price convergence does not necessarily mean a zero or even a very small difference in prices between Day-Ahead and Real-Time Energy Markets. There may be factors, from operating reserve charges to risk that result in a competitive, market-based differential. In addition, convergence cannot occur within any individual day as there is at least a one-day lag after any change in system conditions. As a general matter, virtual offers and bids are based on expectations about both Day-Ahead and Real-Time Market conditions and reflect the uncertainty about conditions in both markets and the fact that these conditions change hourly and daily. Substantial, virtual trading activity does not guarantee that market power cannot be exercised in the Day-Ahead Energy Market. Hourly and daily price differences between the Day-Ahead and Real-Time Energy Markets fluctuate continuously and substantially from positive to negative. (See Figure 2-20.) There may be substantial, persistent differences between day-ahead and real-time prices even on a monthly basis. (See Figure 2-21.)

As Table 2-79, Figure 2-19, Figure 2-20 and Figure 2-21 show, day-ahead and real-time prices were relatively close, on average, during 2007. PJM day-ahead average prices were lower than real-time prices by $2.91 per MWh during 2007. On average, day-ahead prices were lower than real-time prices by $1.17 per MWh during 2006, by $0.19 per MWh in 2005 and by $0.97 per MWh in 2004. On average, day-ahead prices were higher than real-time prices by $0.45 per MWh in 2003, by $0.16 per MWh in 2002, by $0.37 per MWh in 2001 and by $1.61 per MWh in 2000.

Table 2-79 shows that during 2007, average LMP in the Real-Time Energy Market was $2.91 per MWh or 5.1 percent higher than average LMP in the Day-Ahead Energy Market. The real-time median LMP was 4.8 percent lower than day-ahead median LMP, reflecting an average difference of $2.42 per MWh. Price dispersion in the Real-Time Energy Market was 30.7 percent greater than in the Day-Ahead Energy Market, with an average difference in standard deviation between the two of $10.61 per MWh.

Table 2-79 Day-Ahead and Real-Time Energy Market LMP (Dollars per MWh): Calendar year 2007

	Day Ahead	Real Time	Difference	Difference as Percent Real Time
Average	$54.67	$57.58	$2.91	5.1%
Median	$52.34	$49.92	($2.42)	(4.8%)
Standard deviation	$23.99	$34.60	$10.61	30.7%

The price difference between the Real-Time and the Day-Ahead Energy Markets results, in part, from volatility in the Real-Time Energy Market that is difficult, or impossible, to anticipate in the Day-Ahead Energy Market. In 2007, real-time prices were higher than day-ahead prices by more than $50 per MWh for 300 hours, more than $100 per MWh for 45 hours and more than $150 per MWh for 14 hours. In 2006, real-time prices had been higher than day-ahead prices by more than $50 per MWh for 172 hours, more than $100 per MWh for 20 hours, and more than $150 per MWh for 11 hours. If the hours with price differences greater than $150 per MWh are excluded, the difference between real-time and day-ahead price is $2.48 per MWh in 2007 rather than $2.91 and is $0.82 per MWh in 2006 rather than $1.17. Although real-time prices were higher than day-ahead prices on average in 2007, real-time prices were lower than day-ahead prices for 52.9 percent of the hours. During hours when real-time prices were higher than day-ahead prices, the average positive difference between them was $18.65 per MWh. During hours when real-time prices were less than day-ahead prices, the average negative difference was -$11.12 per MWh.

Figure 2-19 shows the 2007 PJM real-time and day-ahead price difference duration curves, with a price difference range limited to -$100 per MWh to $200 per MWh for presentation purposes. Only a few points are not shown in the figure. The PJM real-time price was lower than the day-ahead price by more than $100 per MWh for one hour in 2003, one hour in 2005 and two hours in 2006. The PJM real-time price was higher than the day-ahead price by more than $200 per MWh for seven hours in 2006 and nine hours in 2007.

Figure 2-19 PJM real-time and day-ahead price difference duration curves (-$100/MWh to $200/MWh): Calendar years 2003 to 2007

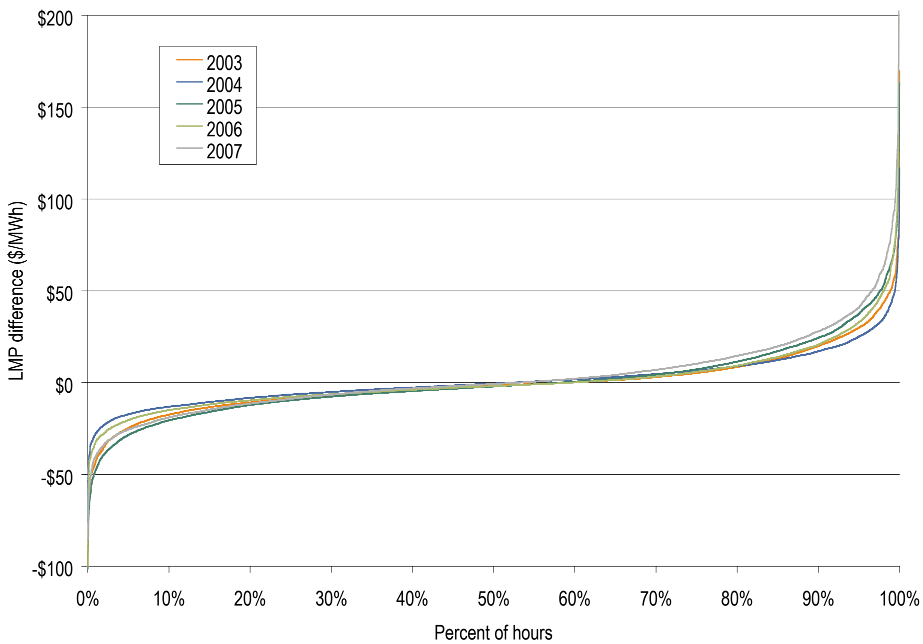


Figure 2-20 shows the hourly differences between day-ahead and real-time LMP in 2007. Although the average difference between the Day-Ahead and Real-Time Energy Market was $2.91 per MWh for the entire year, Figure 2-20 demonstrates the considerable variation, both positive and negative, between day-ahead and real-time prices. The highest difference between real-time and day-ahead LMP was $473.47 per MWh for the hour ended 1700 on August 8, 2007, when the real-time LMP was $673.98 (peak real-time LMP for 2007) and the day-ahead LMP was $200.50.

Figure 2-20 Hourly real-time minus hourly day-ahead LMP: Calendar year 2007

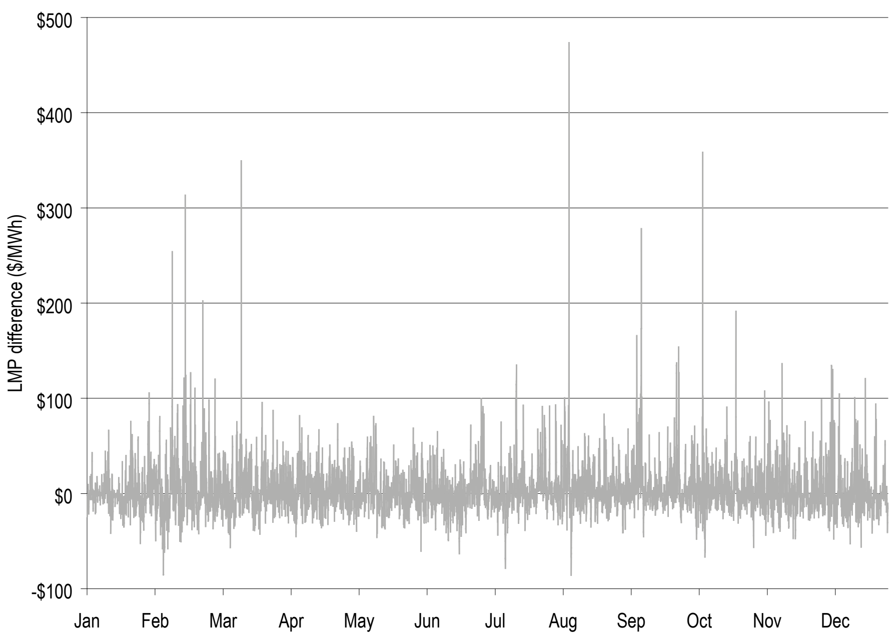
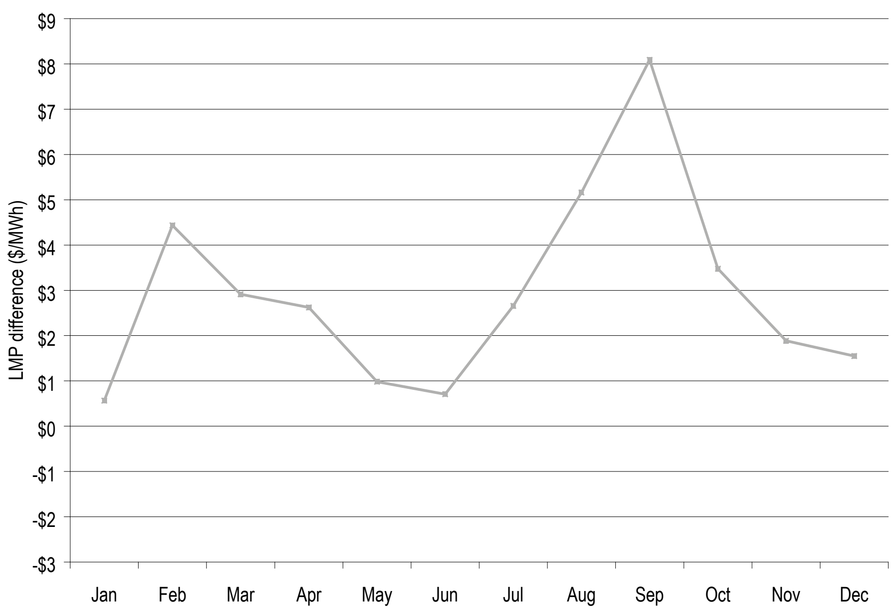


Figure 2-21 shows the monthly average differences between the day-ahead and real-time LMP in 2007. The highest monthly difference was in September. However, as Figure 2-14 shows, the coal, gas, light oil and heavy oil prices in September 2007 were 6.7 percent, 21.6 percent, 22.1 percent and 37.4 percent higher, respectively, than the corresponding fuel prices in September 2006. Further, September 2007 had 627 real-time constrained hours, an increase of 21.7 percent over the real-time constrained hours during September 2006. The day-ahead constrained hours were the same in September 2007 and September 2006.[62]

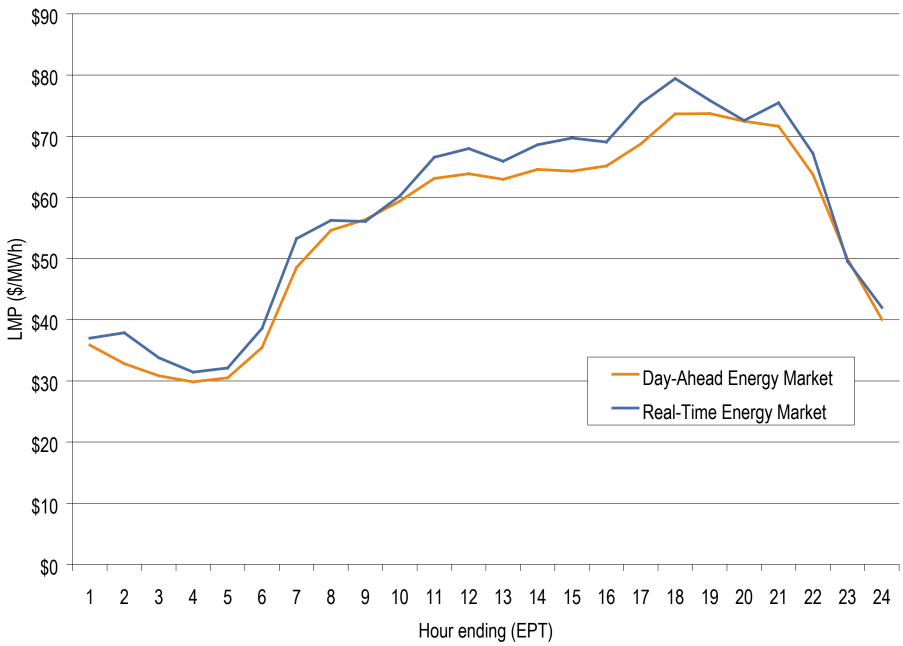
Figure 2-21 Monthly average of real-time minus day-ahead LMP: Calendar year 2007



62 For constrained hour information, see the *2007 State of the Market Report*, Volume II, Appendix C, "Energy Market.," Figure C-1, "PJM real-time constrained hours: Calendar years 2006 to 2007."

Figure 2-22 shows day-ahead and real-time LMP on an average hourly basis. Real-time average LMP was greater than day-ahead average LMP for 22 out of 24 hours.[63]

Figure 2-22 PJM system hourly average LMP: Calendar year 2007



63 See the *2007 State of the Market Report*, Volume II, Appendix C, "Energy Market," for more details on the frequency distribution of prices.

Zonal Price Convergence

Table 2-80 shows 2007 zonal day-ahead and real-time average LMP. The difference between zonal day-ahead and real-time LMP ranged from $0.18 in the DLCO Control Zone to $4.42 in the BGE Control Zone, where the day-ahead average LMP was lower than the real-time average LMP.

Table 2-80 Zonal Day-Ahead and Real-Time Energy Market LMP (Dollars per MWh): Calendar year 2007

	Day Ahead	Real Time	Difference	Difference as Percent Real Time
AECO	$62.96	$65.02	$2.06	3.2%
AEP	$45.55	$46.55	$1.00	2.1%
AP	$54.88	$57.45	$2.57	4.5%
BGE	$65.37	$69.79	$4.42	6.3%
ComEd	$45.35	$45.71	$0.36	0.8%
DAY	$45.29	$46.47	$1.18	2.5%
DLCO	$43.75	$43.93	$0.18	0.4%
Dominion	$63.42	$66.75	$3.33	5.0%
DPL	$61.95	$64.15	$2.20	3.4%
JCPL	$63.18	$65.74	$2.56	3.9%
Met-Ed	$61.62	$64.57	$2.95	4.6%
PECO	$61.25	$62.60	$1.35	2.2%
PENELEC	$52.97	$54.80	$1.83	3.3%
Pepco	$66.44	$70.33	$3.89	5.5%
PPL	$60.00	$62.02	$2.02	3.3%
PSEG	$63.94	$65.92	$1.98	3.0%
RECO	$63.37	$64.85	$1.48	2.3%

Price Convergence by Jurisdiction

Table 2-81 shows the 2007 day-ahead and real-time average LMPs by jurisdiction. The difference between day-ahead and real-time LMP ranged from $0.37 in Illinois to $3.97 in Maryland, where the day-ahead average LMP was lower than the real-time average LMP.

Table 2-81 Jurisdiction Day-Ahead and Real-Time Energy Market LMP (Dollars per MWh): Calendar year 2007

	Day Ahead	Real Time	Difference	Difference as Percent Real Time
Delaware	$61.40	$63.45	$2.05	3.2%
Illinois	$45.34	$45.71	$0.37	0.8%
Indiana	$45.47	$46.24	$0.77	1.7%
Kentucky	$45.40	$46.52	$1.12	2.4%
Maryland	$65.64	$69.61	$3.97	5.7%
Michigan	$46.00	$46.82	$0.82	1.8%
New Jersey	$63.59	$65.78	$2.19	3.3%
North Carolina	$59.83	$62.58	$2.75	4.4%
Ohio	$44.71	$45.69	$0.98	2.1%
Pennsylvania	$56.84	$58.72	$1.88	3.2%
Tennessee	$46.52	$47.32	$0.80	1.7%
Virginia	$61.01	$63.83	$2.82	4.4%
West Virginia	$46.54	$48.39	$1.85	3.8%
District of Columbia	$66.40	$70.25	$3.85	5.5%

Load and Spot Market

Real-Time Load and Spot Market

As a general matter, participants in the PJM Real-Time Energy Market can use their own generation to meet load, to sell in the bilateral market or to sell in the spot market in any hour. Participants can both buy and sell via bilateral contracts and buy and sell in the spot market in any hour. If a participant has positive net bilateral transactions in an hour, it is buying energy through bilateral contracts (bilateral purchase). If a participant has negative net bilateral transactions in an hour, it is selling energy through bilateral contracts (bilateral sale). If a participant has positive net spot transactions in an hour, it is buying energy from the spot market (spot purchase). If a participant has negative net spot transactions in an hour, it is selling energy to the spot market (spot sale).

Real-time load is served by a combination of self-supply, bilateral market purchases and spot market purchases. From the perspective of a single PJM billing organization that serves load, its load could be supplied by any combination of its own generation, net bilateral market purchases and net spot market purchases. PJM billing organizations represent customers having billing accounts with PJM. Supply from its own generation (self-supply) means that the organization is generating power from plants that it owns at the same time that it is meeting load. Supply from bilateral purchases means that the organization is purchasing power under bilateral contracts at the same time that it is meeting load. Supply from spot market purchases means that the organization is not generating enough power from owned plants and/or not purchasing enough power under bilateral contracts to meet load at a defined time and, therefore, is purchasing the required balance from the spot market. Real-Time Energy Market transactions are referred to as spot market activity because they are transactions made in a short-term market.

The PJM system's reliance on self-supply, bilateral contracts and spot purchases to meet real-time load is calculated by summing across all PJM billing organizations that serve load in the Real-Time Energy Market for each hour. Table 2-82 shows the monthly average share of real-time load served by self-supply, bilateral contract and spot purchase in 2006 and 2007 based on billing organizations. For 2007, 95.9 percent of real-time load was supplied by bilateral contract, 3.9 percent by spot market purchase and 0.2 percent by self-supply. Compared with 2006, reliance on bilateral contracts increased by 3.1 percentage points; reliance on spot supply decreased by 2.3 percentage points and reliance on self-supply decreased by 0.8 percentage points in 2007.

Table 2-82 Monthly average percentage of real-time self-supply load, bilateral-supply load and spot-supply load based on billing organizations: Calendar years 2006 to 2007

	2006			2007			Difference in Percentage Points		
	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply
Jan	92.4%	6.5%	1.0%	94.9%	4.5%	0.6%	2.5%	(2.0%)	(0.4%)
Feb	92.5%	6.5%	1.0%	95.3%	4.5%	0.1%	2.8%	(2.0%)	(0.9%)
Mar	92.6%	6.4%	1.0%	95.3%	4.5%	0.2%	2.7%	(1.9%)	(0.8%)
Apr	92.7%	6.2%	1.0%	95.3%	4.5%	0.2%	2.6%	(1.7%)	(0.8%)
May	92.7%	6.2%	1.1%	95.6%	4.2%	0.2%	2.9%	(2.0%)	(0.9%)
Jun	93.2%	5.8%	1.0%	96.1%	3.7%	0.2%	2.9%	(2.1%)	(0.8%)
Jul	93.3%	5.8%	0.9%	96.7%	3.1%	0.2%	3.4%	(2.7%)	(0.7%)
Aug	93.2%	6.0%	0.8%	96.6%	3.3%	0.2%	3.4%	(2.7%)	(0.6%)
Sep	92.8%	6.1%	1.0%	96.5%	3.4%	0.1%	3.7%	(2.7%)	(0.9%)
Oct	92.2%	6.7%	1.1%	96.2%	3.6%	0.2%	4.0%	(3.1%)	(0.9%)
Nov	92.6%	6.3%	1.1%	96.0%	3.8%	0.2%	3.4%	(2.5%)	(0.9%)
Dec	92.6%	6.4%	1.0%	95.9%	3.9%	0.2%	3.3%	(2.5%)	(0.8%)
Annual	92.8%	6.2%	1.0%	95.9%	3.9%	0.2%	3.1%	(2.3%)	(0.8%)

The relative shares of bilateral contracts, spot market transactions and self-supply to supply real-time load are also calculated by summing across all the parent companies of PJM billing organizations. Table 2-83 shows the monthly average share of real-time load served by self-supply, bilateral contract and spot purchase in 2006 and 2007 based on parent company. As Table 2-83 shows, based on parent company, 22.8 percent of 2007 real-time load was supplied by bilateral contracts, 3.9 percent by spot market purchase and 73.3 percent by self-supply. Compared with Table 2-82, while the share of spot transactions is almost identical between the billing organization and parent company approaches, on average, the share of bilateral contracts was lower for parent companies and the share of self-supply was higher. This reflects the fact that, on average, while some load-serving affiliates purchased their needs bilaterally, generation affiliates of the corresponding parent also sold power under bilateral contracts in the PJM Real-Time Energy Market.

Table 2-83 Monthly average percentage of real-time self-supply load, bilateral supply load and spot supply load based on parent companies: Calendar years 2006 to 2007

	2006			2007			Difference in Percentage Points		
	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply
Jan	19.4%	5.4%	75.2%	22.0%	3.7%	74.4%	2.6%	(1.7%)	(0.8%)
Feb	19.4%	5.1%	75.5%	22.3%	3.8%	73.9%	2.9%	(1.3%)	(1.6%)
Mar	19.9%	5.0%	75.2%	21.6%	4.0%	74.4%	1.7%	(1.0%)	(0.8%)
Apr	20.1%	4.4%	75.5%	22.4%	4.7%	72.9%	2.3%	0.3%	(2.6%)
May	19.9%	4.6%	75.5%	22.4%	3.9%	73.7%	2.5%	(0.7%)	(1.8%)
Jun	20.6%	4.7%	74.8%	22.8%	3.1%	74.0%	2.2%	(1.6%)	(0.8%)
Jul	20.5%	6.3%	73.2%	23.9%	4.3%	71.8%	3.4%	(2.0%)	(1.4%)
Aug	20.6%	5.5%	73.9%	23.8%	3.6%	72.6%	3.2%	(1.9%)	(1.3%)
Sep	20.5%	5.1%	74.4%	23.1%	3.8%	73.2%	2.6%	(1.3%)	(1.2%)
Oct	20.9%	5.5%	73.6%	23.7%	5.5%	70.8%	2.8%	0.0%	(2.8%)
Nov	20.2%	5.4%	74.4%	22.8%	4.3%	73.0%	2.6%	(1.1%)	(1.4%)
Dec	19.6%	5.2%	75.2%	22.3%	2.8%	74.9%	2.7%	(2.4%)	(0.3%)
Annual	20.1%	5.2%	74.6%	22.8%	3.9%	73.3%	2.7%	(1.3%)	(1.3%)

Day-Ahead Load and Spot Market

In the PJM Day-Ahead Energy Market, participants can use not only their own generation, bilateral contracts and spot market purchases to supply their obligations as in the Real-Time Energy Market, but also can use virtual resources to meet their obligations in any hour. Participants can both buy and sell virtual resources (increment offers and decrement bids). If a participant has a positive net virtual position in an hour, it is selling energy in the Day-Ahead Energy Market. If a participant has a negative net virtual position in an hour, it is buying energy in the Day-Ahead Market.

The PJM system's reliance on self-supply, bilateral contracts, spot purchases and virtual resources to meet day-ahead load (cleared fixed-demand and price-sensitive load) is calculated by summing across all PJM billing organizations that serve load in the Day-Ahead Energy Market for each hour. Table 2-84 shows the monthly average share of day-ahead load served by self-supply, bilateral contracts, spot purchases and virtual resources in 2006 and 2007, based on billing organizations. For 2007, 20.1 percent of day-ahead load was supplied by bilateral contracts, 36.0 percent by spot market purchases, 32.5 percent by self-supply and 11.3 percent by virtual resources. Compared with 2006, reliance on bilateral contracts decreased by 9.5 percentage points, reliance on spot supply increased by 3.8 percentage points, reliance on self-supply increased by 4.3 percentage points and reliance on virtual-supply increased by 1.3 percentage points in 2007.

Table 2-84 Monthly average percentage of day-ahead self-supply load, bilateral supply load, spot and virtual supply load based on billing organizations: Calendar years 2006 to 2007

	2006				2007				Difference in Percentage Points			
	Bilateral Contract	Spot	Self-Supply	Virtual	Bilateral Contract	Spot	Self-Supply	Virtual	Bilateral Contract	Spot	Self-Supply	Virtual
Jan	29.6%	31.3%	30.2%	8.9%	18.6%	36.1%	33.8%	11.5%	(11.0%)	4.8%	3.6%	2.6%
Feb	29.8%	31.5%	30.3%	8.3%	20.4%	36.7%	32.8%	10.0%	(9.4%)	5.2%	2.5%	1.7%
Mar	29.9%	31.5%	29.6%	9.0%	20.4%	35.4%	32.5%	11.7%	(9.5%)	3.9%	2.9%	2.7%
Apr	29.7%	31.5%	29.6%	9.3%	20.2%	35.3%	32.3%	12.2%	(9.5%)	3.8%	2.7%	2.9%
May	29.6%	31.4%	29.4%	9.7%	20.7%	35.1%	32.1%	12.2%	(8.9%)	3.7%	2.7%	2.5%
Jun	29.1%	32.3%	28.1%	10.5%	19.8%	36.6%	31.8%	11.7%	(9.3%)	4.3%	3.7%	1.2%
Jul	30.7%	33.4%	26.2%	9.7%	19.9%	36.7%	31.6%	11.9%	(10.8%)	3.3%	5.4%	2.2%
Aug	29.7%	33.8%	26.6%	9.9%	19.0%	36.4%	33.0%	11.6%	(10.7%)	2.6%	6.4%	1.7%
Sep	29.2%	32.2%	27.2%	11.4%	20.1%	36.2%	32.4%	11.3%	(9.1%)	4.0%	5.2%	(0.1%)
Oct	29.1%	32.0%	27.5%	11.4%	20.2%	36.0%	31.9%	11.8%	(8.9%)	4.0%	4.4%	0.4%
Nov	29.5%	31.7%	27.6%	11.2%	21.1%	35.2%	32.7%	11.0%	(8.4%)	3.5%	5.1%	(0.2%)
Dec	28.9%	33.1%	27.1%	10.9%	21.4%	36.5%	32.8%	9.3%	(7.5%)	3.4%	5.7%	(1.6%)
Annual	29.6%	32.2%	28.2%	10.0%	20.1%	36.0%	32.5%	11.3%	(9.5%)	3.8%	4.3%	1.3%

The relative shares of bilateral contracts, spot market transactions, self-supply and virtual resources to meet day-ahead load (cleared fixed-demand and price-sensitive load) are also calculated by summing across all the parent companies of PJM billing organizations that serve load in the Day-Ahead Energy Market for each hour. As Table 2-85 shows, based on parent companies, 5.3 percent of day-ahead load was supplied by bilateral contracts, 14.9 percent by spot market purchases, 67.4 percent by self-supply and 12.3 percent by virtual-supply for 2007. Compared with Table 2-84, while the share of spot transactions and the share of bilateral contracts were lower for parent companies, the share of self-supply was higher. This reflects the fact that, on average, while some load-serving affiliates purchased some of their needs bilaterally, generation affiliates of the corresponding parent also sold power under bilateral contracts in the PJM Day-Ahead Energy Market. The reduction, on average, in the reliance on spot transactions by parent companies reflects the fact that some parent companies have both spot sales and spot purchases and that the spot purchases are more concentrated in the load-serving affiliates.

Table 2-85 Monthly average percentage of day-ahead self-supply load, bilateral supply load, spot and virtual supply load based on parent companies: Calendar years 2006 to 2007

	2006				2007				Difference in Percentage Points			
	Bilateral Contract	Spot	Self-Supply	Virtual	Bilateral Contract	Spot	Self-Supply	Virtual	Bilateral Contract	Spot	Self-Supply	Virtual
Jan	3.2%	8.0%	79.0%	9.8%	4.6%	13.9%	68.8%	12.6%	1.4%	5.9%	(10.2%)	2.8%
Feb	3.4%	8.4%	78.8%	9.4%	4.8%	13.6%	69.0%	12.6%	1.4%	5.2%	(9.8%)	3.2%
Mar	3.7%	8.8%	77.6%	9.9%	5.0%	14.0%	67.9%	13.1%	1.3%	5.2%	(9.7%)	3.2%
Apr	3.7%	7.9%	78.5%	10.0%	5.2%	13.8%	67.8%	13.2%	1.5%	5.9%	(10.7%)	3.2%
May	3.9%	9.3%	77.0%	9.7%	6.0%	13.0%	67.5%	13.4%	2.1%	3.7%	(9.5%)	3.7%
Jun	4.0%	9.2%	75.8%	11.0%	5.3%	15.0%	67.0%	12.6%	1.3%	5.8%	(8.8%)	1.6%
Jul	4.4%	9.8%	75.1%	10.7%	5.2%	16.0%	66.3%	12.5%	0.8%	6.2%	(8.8%)	1.8%
Aug	4.5%	9.1%	75.5%	11.0%	4.9%	15.5%	67.7%	12.0%	0.4%	6.4%	(7.8%)	1.0%
Sep	5.1%	9.3%	74.0%	11.5%	5.6%	15.9%	66.9%	11.5%	0.5%	6.6%	(7.1%)	0.0%
Oct	5.2%	10.1%	73.5%	11.2%	5.7%	17.0%	65.0%	12.3%	0.5%	6.9%	(8.5%)	1.1%
Nov	4.8%	9.2%	74.2%	11.8%	6.0%	15.8%	66.8%	11.4%	1.2%	6.6%	(7.4%)	(0.4%)
Dec	4.7%	9.2%	74.0%	12.1%	6.1%	15.6%	68.2%	10.1%	1.4%	6.4%	(5.8%)	(2.0%)
Annual	4.2%	9.0%	76.0%	10.7%	5.3%	14.9%	67.4%	12.3%	1.1%	5.9%	(8.6%)	1.6%

Demand-Side Response (DSR)

Markets require both a supply side and a demand side to function effectively. The demand side of wholesale electricity markets is underdeveloped. It is widely recognized that wholesale electricity markets will work better when a significant level of potential demand-side response is available in the market. PJM wholesale market, demand-side programs should be understood as one relatively small part of a transition to a fully functional demand side for its Energy Market. A fully developed demand side will include retail programs and an active, well-articulated interaction between wholesale and retail markets.

A functional demand side of the electricity market does not mean that all customers curtail usage at specified levels of price. A fully functional demand side of the electricity market does mean that the default energy price for all customers will be the day-ahead or real-time hourly LMP. Customers will be able to choose to pay the day-ahead or real-time prices or to hedge their exposure to those prices by using an intermediary. A fully functional demand side of the electricity market does mean that all or most customers, or their designated intermediaries, will have the ability to see real-time prices in real time, will have the ability to react to real-time prices in real time and will have the ability to receive the direct benefits or costs of changes in real-time energy use, based on real-time energy prices. In addition, customers will be able to specify the maximum price at which they wish to purchase power in the Day-Ahead Market. If these conditions are met, customers can decide for themselves the relationship between the price of power and the value of particular activities, from operating a production plant to running a commercial building to running a residential air conditioner. The true goal of demand-side programs is to ensure that customers can make informed decisions about energy consumption. Customers can and will make investments in demand-side management technologies based on their own evaluations of the tradeoffs among the price of power, the value of particular activities and the costs of those technologies.

A functional demand side of the wholesale energy market does not necessarily mean that prices will be lower than they otherwise would be. A functional demand side of these markets does mean, however, that customers will have the ability to make decisions about levels of power consumption based both on the value of the uses of the power and on the actual cost of that power.

A functional demand side of the wholesale electricity market would also send explicit price signals to suppliers, inducing more competitive behavior among suppliers and providing a market-based limit to suppliers' ability to exercise market power. If customers had the essential tools to respond to prices, then suppliers would have the incentive to deliver power on a cost-effective basis, consistent with their customers' evaluations.

The purpose of PJM's demand-side Economic Program is, or should be, to address a specific market failure, which is that many retail customers do not pay the market price or LMP. This represents a market failure because when customers do not pay the market price, the behavior of those customers is inconsistent with the market value of electricity. When customers pay a price less than the market price, customers will tend to consume more than if they faced the market price and when customers pay a price greater than the market price, customers will tend to consume less than they would if they faced the market price. This market failure is relevant to the wholesale power market because the power used by customers is generated and sold in the wholesale power market.

Based on this purpose, the design goal of the Economic Program incentives should be to replicate the price signal to customers that would exist if customers were exposed to the real-time wholesale price. The real-time hourly LMP is the appropriate price signal as it reflects the incremental value of each MWh consumed.[64] The goal of the program should be neither to encourage increased or decreased consumption, but to permit customers to face the market price and to make consumption decisions consistent with that price.

The PJM Economic Program is a wholesale program and its goal should be to ensure that the appropriate wholesale price signal is provided to customers but should not be to address retail rate issues. The design of retail incentives is a matter for state public utility commissions.

Retail customers pay retail rates including components that reflect the cost of generation (or power purchased from the grid), the cost of transmission and the cost of distribution. Under a rate design consistent with the purpose of the demand-side program, the hourly LMP would replace only the generation component of retail rates in order to provide the appropriate wholesale market price signal to customers. The LMP reflects the economic value of wholesale power and does not reflect the value of transmission or distribution services.

64 This does not mean that every retail customer should be required to pay the real-time LMP, regardless of their risk preferences. However, it would provide the appropriate price signal if every retail customer were obligated to pay the real-time LMP as a default. That risk could be hedged via a contract with an intermediary.

On March 15, 2002, PJM submitted filing amendments to the OATT and to the OA to establish a multiyear Economic Load-Response Program (the Economic Program).[65] On May 31, 2002, the FERC accepted the Economic Program, effective June 1, 2002, but with a December 1, 2004, sunset provision.[66] On October 29, 2004, the FERC extended the Economic Program until December 31, 2007.[67] On February 24, 2006, the FERC approved changes to the PJM Tariff to permit demand-side resources to provide ancillary services and to make the Economic Program permanent.[68, 69] The same order permitted, for individual participants using the nonhourly metered option, an increase in the limit on the combined total MW in the Economic and Emergency Programs from 100 MW to 500 MW.

On November 20, 2007, the PJM Industrial Customer Coalition (PJMICC) filed a complaint with the FERC requesting continuation of Economic Load-Response subsidy payments that, under the existing PJM Tariff, would expire on December 31, 2007.[70] The Commission denied the complaint, stating that "Even without the subsidy payments, the Economic Program provides customers within PJM the incentive to reduce load based on the wholesale rates they confront."[71, 72] On December 31, 2007, the Economic Program incentive payment provisions expired per the PJM OA.

The PJM Economic Load-Response Program is a PJM-managed accounting mechanism that provides for payment of the savings that result from load reductions to the load-reducing customer. Such a mechanism is required because of the complex interaction between the wholesale market and the retail incentive and regulatory structures faced by both load-serving entities (LSEs) and customers. The broader goal of the Economic Program is a transition to a structure where customers do not require mandated payments, but where customers see and react to market prices or enter into contracts with intermediaries to provide that service. Even as currently structured, however, the Economic Program represents a minimal and relatively efficient intervention into the market.

On February 14, 2002, the PJM Members Committee approved a permanent Emergency Load-Response Program.[73] On March 1, 2002, PJM filed amendments to the OATT and to the OA to establish a permanent Emergency Load-Response Program (the Emergency Program).[74] By order dated April 30, 2002, the FERC approved the Emergency Program effective June 1, 2002. Like the Economic Program, a sunset date for it was set for December 1, 2004.[75] On October 29, 2004, the FERC extended the program until December 31, 2007, thereby making it coterminous with the Economic Program.[76] On February 24, 2006, the FERC approved changes to the PJM Tariff to make the Emergency Program permanent, including energy only and full emergency options.[77]

65 *PJM Interconnection, L.L.C.,* Tariff Amendments, Docket No. ER02-1326-000 (March 15, 2002).

66 99 FERC ¶ 61,227 (2002).

67 *PJM Interconnection, L.L.C.,* Letter Order, Docket No. ER04-1193-000 (October 29, 2004).

68 114 FERC ¶ 61,201 (February 24, 2006).

69 Analysis of the role of demand-side resources in the Ancillary Service Markets can be found in the *2007 State of the Market Report*, Volume II, Section 6, "Ancillary Service Markets," at "Synchronized Reserve Market."

70 See PJM. "Amended and Restated Operating Agreement (OA)," Schedule 1, Section 3.3.A (December 10, 2007).

71 121 FERC ¶ 61,315 (December 31, 2007) at ¶ 26.

72 For a discussion of subsidy payments under PJM's Economic Load-Response Program, see "MMU White Paper: PJM Demand Side Response Program" (December 4, 2007) <http://www.pjm.com/markets/market-monitor/downloads/20071204-dsr-whitepaper.pdf> (118.4 KB).

73 PJM Interconnection, L.L.C., Tariff Amendments, Docket No. ER02-1205-000 (March 1, 2002).

74 PJM Interconnection, L.L.C., Tariff Amendments, Docket No. ER02-1205-000 (March 1, 2002).

75 99 FERC ¶ 61,139 (2002).

76 PJM Interconnection, L.L.C., Letter Order, Docket No. ER04-1193-000 (October 29, 2004).

77 114 FERC ¶ 61,201 (February 24, 2006).

As of result of Reliability Pricing Model (RPM) implementation on June 1, 2007, the Emergency Program was modified to include an Emergency-Capacity Only option, to provide capacity credits to customers with Emergency-Full and Emergency-Capacity Only options, to make customers with the Emergency-Full option eligible for an Emergency-Energy payment for reductions during emergency events and to provide penalties for noncompliance during emergency events for customers with the Emergency-Full and Emergency-Capacity Only options.[78]

As part of the transition to RPM, effective June 1, 2007, the PJM active load management (ALM) program was changed to the load management (LM) program.[79] Customers offering resources into an RPM Auction are paid the resource-clearing price. Interruptible load for reliability (ILR) resources have to be certified at least three months prior to the delivery year and are paid the final zonal ILR price.

The LM program is comprised of two types of resources: ILR resources and demand resources (DR). An ILR resource can be registered under the Emergency-Capacity Only or Emergency-Full options of the Emergency and Economic Programs simultaneously. A DR resource can also be registered under the Emergency-Full option of the Emergency and Economic Programs simultaneously. However, a customer can participate in only one of the programs within an hour.

Customers with Emergency-Full and Emergency-Capacity Only options receive capacity credits on a daily basis. Customers with the Emergency-Full option are also eligible for an Emergency-Energy payment for reductions during emergency events. Customers with Emergency-Full and Emergency-Capacity Only options are obligated to respond during emergency events and face penalties for noncompliance.[80] The Emergency-Energy Only option is voluntary; customers who register for this option do not have to reduce their load during emergency events. Credits are paid to Emergency-Energy Only customers in the event of load reductions.

Emergency Program

The zonal distribution of DSR capability in the Emergency-Energy Only option of the Emergency Program is shown in Table 2-86. On August 8, 2007, the peak-load day for the year, there were 9.25 MW of available resources in the Emergency-Energy Only option of the Emergency Program.[81] There was no activity under this option in calendar year 2007.

Table 2-86 also shows the zonal distribution of DSR capability in the Emergency-Full option and in the Emergency-Capacity option of the Emergency Program on August 8, 2007. The BGE Control Zone included 20 percent of all registered sites and 23 percent of all registered MW under the Emergency-Full option. The ComEd Control Zone included 61 percent of all registered sites and 37 percent of all registered MW in the capacity option of the Emergency Program.

78 For additional information on RPM provisions for customers in the Emergency Load-Response Program, refer to PJM's "Manual 18: "PJM Capacity Market."

79 An LM program continues to have three types of products: direct load control, firm service level or guaranteed load drop. Each of the products continues to have two notification periods: short-lead time and long-lead time.

80 "Emergency-Full customers that failed to provide a load reduction dispatched by PJM shall be assessed the ALM Deficiency Charge. The ALM Deficiency Charge shall equal the lesser of the Compliance Deficiency Value multiplied by the Daily Capacity Deficiency Rate multiplied by 365/10, or the Compliance Deficiency value multiplied two times the Annual Value of the Capacity Credit divided by a factor of 5." PJM. "Manual 28: Operating Agreement Accounting," Revision 39 (January 1, 2008), p. 70.

81 The number of registered sites and MW levels are measured as a one-day snapshot. The one-day snapshot is used because retail customers may change curtailment service providers (CSP) multiple times within a year and each such change would require a registration. When switching occurs, an annual total of registered sites would count the same sites and MW multiple times.

Table 2-86 Zonal capability in the Emergency Program (By option): August 8, 2007

	Energy Only		Full		Capacity Only	
	Sites	MW	Sites	MW	Sites	MW
AECO	2	2.00	25	3.70	3	3.10
AEP	0	0.00	12	437.60	9	118.40
AP	0	0.00	4	45.30	6	63.60
BGE	2	7.25	40	234.70	12	21.60
ComEd	0	0.00	6	64.80	306	409.80
DAY	0	0.00	0	0.00	0	0.00
DLCO	0	0.00	0	0.00	2	2.30
Dominion	0	0.00	0	0.00	3	10.90
DPL	0	0.00	14	54.10	5	4.40
JCPL	0	0.00	8	6.70	6	49.70
Met-Ed	0	0.00	7	8.80	13	33.20
PECO	0	0.00	28	77.30	63	110.20
PENELEC	0	0.00	2	1.50	1	0.00
Pepco	0	0.00	6	9.00	4	19.30
PPL	0	0.00	16	9.30	62	236.40
PSEG	0	0.00	34	88.70	8	20.90
RECO	0	0.00	0	0.00	0	0.00
Total	4	9.25	202	1,041.50	503	1,103.80

In 2007, there was one day with emergency activity, August 8, 2007, the day of the system's annual peak. The period of compliance for the Emergency Program occurred between the hours ending 1500 EPT and 1800 EPT in the Mid-Atlantic and Southern regions.[82] Zonal real-time, load-weighted, average LMPs were between $208.81 per MW and $1,059.13 per MW during the emergency activity within the Mid-Atlantic and Southern regions. The Emergency Program reductions on August 8, 2007, occurred during and after the scarcity pricing event that was triggered for certain scarcity pricing zones within the Mid-Atlantic and Southern regions.[83]

Table 2-87 shows the overcompliance and undercompliance of resources in the Emergency Program by ILR and DR resources on August 8, 2007, within the zones where the emergency event was called. Altogether, ILR resources overcomplied by 7.6 MW and DR resources overcomplied by 15.4 MW during the emergency activity.

82 Compliance hours are defined as a full hour during the emergency event. For example, if event started in 1530 and is over at 1720, only the hour between 1600 and 1700 (i.e., hour ending 17) will be counted as a compliance hour by PJM.

83 For a complete discussion of the August 8, 2007, scarcity pricing events, see the *2007 State of the Market Report*, Volume II, Section 3, "Energy Market, Part 2," "2007 High-Load Events, Scarcity and Scarcity Pricing Events."

Table 2-87 Zonal overcompliance and undercompliance of ILR and DR capacity resources (MW): August 8, 2007

	Committed UCAP		Over / (Under)compliance		Actual Reduction	
	DR	ILR	DR	ILR	DR	ILR
AECO	0.00	6.90	0.00	1.50	0.00	8.40
BGE	14.70	249.30	3.00	1.70	17.70	251.00
Dominion	0.00	11.30	0.00	2.90	0.00	14.20
DPL	5.10	27.40	0.30	1.10	5.40	28.50
JCPL	0.00	9.80	0.00	1.30	0.00	11.10
Met-Ed	1.20	36.50	(0.70)	2.90	0.50	39.40
PECO	12.30	101.40	(0.20)	(27.30)	12.10	74.10
PENELEC	0.00	1.50	0.00	2.20	0.00	3.70
Pepco	5.00	23.90	13.00	7.30	18.00	31.20
PPL	0.00	252.30	0.00	13.00	0.00	265.30
PSEG	0.00	106.40	0.00	1.00	0.00	107.40
Total	38.30	826.70	15.40	7.60	53.70	834.30

Table 2-88 shows the zonal, Emergency-Full option, energy MWh participation levels and associated payments during the emergency activity of August 8, 2007.[84] In total $878,828 credits were paid for 1,005 MWh that responded during the emergency hours.[85]

Table 2-88 Zonal Emergency-Full option energy payments and MWh participation: August 8, 2007

	MWh	Payments
AECO	8.4	$8,517
BGE	130.9	$131,380
DPL	227.3	$201,897
JCPL	31.8	$31,903
Met-Ed	9.7	$9,193
PECO	75.1	$75,427
PENELEC	13.7	$11,182
Pepco	129.5	$130,672
PPL	17.2	$17,205
PSEG	361.7	$261,451
Total	1,005.2	$878,828

84 Energy MWh and payments for each zone are calculated for hours of emergency activity rather than for the compliance hours of the emergency. Hours of emergency activity may include lead times prior to the emergency event for each zone.

85 The hourly energy payment for the Emergency-Full option is equal to the sum of the customer's shutdown cost (once per day) and the product of the MWh reduction and the greater of zonal load-weighted LMP or customer submitted strike price. Strike price is the LMP specified by a customer at which load shall be reduced.

Table 2-89 shows zonal monthly capacity credits that were paid during the June 1, 2007, through December 31, 2007, period to ILR and DR resources. The total amount of the credits was $34,454,412.[86] November credits include credits and charges for overcompliance and undercompliance by ILR and DR resources on August 8, 2007.

Table 2-89 Zonal monthly capacity credits: June 1, 2007, through December 31, 2007

	June	July	August	September	October	November	December
AECO	$36,745	$37,969	$37,969	$36,745	$37,969	$44,712	$37,969
AEP	$147,247	$152,155	$152,155	$147,247	$152,155	$147,247	$152,155
AP	$137,700	$142,290	$142,290	$137,700	$142,290	$137,700	$142,290
BGE	$1,131,403	$1,169,116	$1,169,116	$1,131,403	$1,169,116	$1,164,145	$1,169,116
COMED	$598,781	$618,740	$618,740	$598,781	$618,740	$598,781	$618,740
DAY	$2,448	$2,530	$2,530	$2,448	$2,530	$2,448	$2,530
Dominion	$13,831	$14,292	$14,292	$13,831	$14,292	$22,492	$14,292
DPL	$338,049	$349,317	$349,317	$338,049	$349,317	$343,714	$349,317
DLCO	$2,815	$2,909	$2,909	$2,815	$2,909	$2,815	$2,909
JCPL	$308,867	$319,163	$319,163	$308,867	$319,163	$319,246	$319,163
Met-Ed	$53,366	$55,145	$55,145	$53,366	$55,145	$57,846	$55,145
PECO	$1,033,625	$1,068,079	$1,068,079	$1,033,625	$1,068,079	$660,645	$1,068,079
PENELEC	$1,836	$1,897	$1,897	$1,836	$1,897	$7,809	$1,897
Pepco	$128,776	$133,068	$133,068	$128,776	$133,068	$289,702	$133,068
PPL	$309,917	$320,247	$320,247	$309,917	$320,247	$348,742	$320,247
PSEG	$600,694	$620,717	$620,717	$600,694	$620,717	$583,626	$620,717
RECO	$0	$0	$0	$0	$0	$0	$0
Total	$4,846,099	$5,007,636	$5,007,636	$4,846,099	$5,007,636	$4,731,670	$5,007,636

Economic Program

On August 8, 2007, there were 2,498.03 MW registered in the Economic Program compared to the 1,100.65 MW on August 2, 2006, an increase of 127 percent. (See Table 2-90.)

Table 2-90 Economic Program registration: Within 2002 to 2007

	Sites	Peak-Day, Registered MWh
14-Aug-02	96	335.40
22-Aug-03	240	650.56
03-Aug-04	782	875.56
26-Jul-05	2,548	2,210.18
02-Aug-06	253	1,100.65
08-Aug-07	2,897	2,498.03

86 Since ILR and DR resources are paid capacity credits on a daily basis, monthly zonal capacity credits are equal for months with the same number of days. The level of ILR and DR MW that are paid capacity credits was established in the RPM for the period from June 2007 to May 2008.

Table 2-91 shows the zonal distribution of capability in the Economic Program on August 8, 2007. The ComEd Control Zone includes 76 percent of sites and 27 percent of registered MW in the Economic Program.

Table 2-91 Zonal capability in the Economic Program: August 8, 2007

	Sites	MW
AECO	23	19.86
AEP	2	121.00
AP	27	231.05
BGE	152	393.75
ComEd	2,193	667.32
DAY	1	3.50
DLCO	6	64.70
Dominion	26	191.80
DPL	95	126.46
JCPL	36	57.40
Met-Ed	17	52.77
PECO	121	175.28
PENELEC	10	47.15
Pepco	6	14.05
PPL	53	200.53
PSEG	127	130.82
RECO	2	0.60
Total	2,897	2,498.03

The total MWh of load reduction and the associated payments under the Economic Program are shown in Table 2-92.[87] Load reduction levels increased to 608,745 MWh in calendar year 2007.[88] Payments per MWh were $74 in 2007. The Economic Program's actual load reduction per peak-day, registered MW rose to 243.7 MWh for calendar year 2007, an increase of 3.8 percent from 2006.[89]

In the calendar year 2007, the maximum hourly load reduction attributable to the Economic Program was 1,032 MW on August 2.

87 The "Total MWh" and "Total Payments" shown in Table 2-92 for calendar year 2005 are different from those reported in the MMU report, "Assessment of PJM Load-Response Program" filed on August 29, 2006, with the FERC, as a result of settlement adjustments made since that time. The "Total MWh" and "Total Payments" for both the Economic and the Emergency Programs shown here are also subject to subsequent settlement adjustments in 2008.

88 The Economic Program payments and MWh presented in this report do not include all settlement adjustments for 2006 and 2007. The data are provided by PJM's DSR department; Economic Program payments and MWh reductions are based on the January 2008, PJM billing information and are subject to adjustments.

89 The "Total MWh" and "Total Payments" for calendar year 2006 are different from those reported in the *2006 State of the Market Report,* as a result of settled disputes. The "Total MWh" increased by 11,472 MWh and the "Total Payments" increased by $1,217,695.

Table 2-92 Performance of PJM Economic Program participants

	Total MWh	Total Payments	$/MWh	Total MWh per Peak-Day, Registered MW
2002	6,727	$801,119	$119	20.1
2003	19,518	$833,530	$43	30.0
2004	58,352	$1,917,202	$33	66.6
2005	157,421	$13,036,482	$83	71.2
2006	258,468	$18,584,013	$72	234.8
2007	608,745	$45,173,237	$74	243.7

In 2007, Economic Program participants in the PECO Control Zone accounted for 42 percent of all real-time reductions and received 32 percent of all real-time payments. (See Table 2-93.) The total number of curtailed hours for the Economic Program was 208,227 and the total payment amount was $45,173,237.[90]

Overall, approximately 92 percent of the MWh reductions, 89 percent of payments and 92 percent of curtailed hours resulted from the real-time option under the Economic Program.[91] Approximately 5 percent of the MWh reductions, 6 percent of payments and 2 percent of curtailed hours resulted from the day-ahead option.[92] Approximately 3 percent of the MWh reductions, 5 percent of the payments and 7 percent of the curtailed hours resulted from the dispatched-in-real-time option of the program. (See Table 2-93.)

90 If two different retail customers curtail during the same hour in the same zone, it is counted as two curtailed hours.

91 "Real-Time" reductions are self-scheduled reductions and "Dispatched in Real-Time" reductions that are dispatched by PJM in real-time.

92 On February 2, 2007, PJM proposed to the FERC that customers with day-ahead, LMP-based contracts be eliminated from participation in the day-ahead Economic Program. On June 15, 2007, the Commission issued an order, 119 FERC ¶ 61,280, rejecting PJM's proposed revision to its OATT.

Table 2-93 PJM Economic Program by zonal reduction: Calendar year 2007

	Real Time			Day Ahead			Dispatched in Real Time			Totals		
	MWh	Credits	Hours	MWh	Credits	Hours	MWh	Credits	Hours	MWh	Credits	Hours
AECO	250	$18,530	802	0	($7)	3	267	$9,604	339	516	$28,126	1,144
AEP	1,969	$84,867	192	0	$0	0	0	$0	0	1,969	$84,867	192
AP	63,172	$4,199,874	15,177	0	($1,042)	9	690	$73,167	1,037	63,861	$4,272,000	16,223
BGE	56,652	$7,787,520	11,822	0	$0	0	6,374	$908,321	130	63,025	$8,695,840	11,952
ComEd	32,275	$1,416,493	14,723	990	$43,015	1,283	3,510	$258,964	2,226	36,775	$1,718,472	18,232
DAY	0	$0	0	47	$4,225	48	8	$603	3	55	$4,827	51
DLCO	954	$60,654	1,060	0	$0	0	36	$2,295	18	989	$62,949	1,078
Dominion	36,433	$3,807,981	8,790	0	$0	0	585	$68,499	1,343	37,018	$3,876,480	10,133
DPL	8,311	$877,016	6,156	6,503	$831,535	645	42	$8,604	3	14,857	$1,717,155	6,804
JCPL	241	$9,582	448	12,506	$1,379,116	346	44	$4,901	64	12,791	$1,393,599	858
Met-Ed	3,043	$246,723	1,329	218	$43,959	46	176	$14,553	1,244	3,438	$305,235	2,619
PECO	236,562	$13,030,066	107,528	9,346	$475,566	652	3,845	$521,428	5,021	249,753	$14,027,060	113,201
PENELEC	128	$6,017	397	5	$923	4	172	$10,836	285	305	$17,775	686
Pepco	35,750	$3,430,294	3,218	0	$0	0	164	$10,200	601	35,914	$3,440,494	3,819
PPL	81,780	$4,979,800	12,946	1,000	$65,911	219	186	$24,951	475	82,967	$5,070,663	13,640
PSEG	2,781	$253,052	6,280	335	$57,575	47	1,352	$143,659	1,103	4,469	$454,286	7,430
RECO	41	$3,258	156	1	$150	9	0	$0	0	43	$3,408	165
Total	560,343	$40,211,728	191,024	30,952	$2,900,924	3,311	17,449	$2,060,585	13,892	608,745	$45,173,237	208,227
Max	236,562	$13,030,066	107,528	12,506	$1,379,116	1,283	6,374	$908,321	5,021	249,753	$14,027,060	113,201
Avg	32,961	$2,365,396	11,237	1,821	$170,643	195	1,026	$121,211	817	35,809	$2,657,249	12,249

The Economic Load-Response Program in 2007 provided for larger payments when LMP was greater than, or equal to, $75 per MWh. This additional payment is termed a subsidy or incentive payment. About 43 percent of all MWh reductions, 47 percent of all curtailed hours and 12 percent of all Economic Program payments occurred when LMP was less than $75 per MWh. Table 2-94 shows that reductions under the Economic Program when zonal, load-weighted, average LMP was less than $75 per MWh were dispersed over all hours of the day, with somewhat lower levels of activity in the hours ended 0100 EPT through 0600 EPT and the hour ended 2400 EPT.

Table 2-94 Frequency distribution of Economic Program hours when zonal, load-weighted, average LMP less than $75 MWh (By hours): Calendar year 2007

Hour	Frequency	Percent	Cumulative Frequency	Cumulative Percent
1	1,651	1.69%	1,651	1.69%
2	1,890	1.93%	3,541	3.61%
3	1,936	1.98%	5,477	5.59%
4	2,777	2.83%	8,254	8.42%
5	3,045	3.11%	11,299	11.53%
6	3,594	3.67%	14,893	15.20%
7	4,040	4.12%	18,933	19.32%
8	4,633	4.73%	23,566	24.05%
9	5,203	5.31%	28,769	29.36%
10	5,868	5.99%	34,637	35.35%
11	5,478	5.59%	40,115	40.94%
12	5,275	5.38%	45,390	46.33%
13	5,579	5.69%	50,969	52.02%
14	5,421	5.53%	56,390	57.55%
15	4,866	4.97%	61,256	62.52%
16	4,762	4.86%	66,018	67.38%
17	4,559	4.65%	70,577	72.03%
18	4,038	4.12%	74,615	76.16%
19	4,572	4.67%	79,187	80.82%
20	4,693	4.79%	83,880	85.61%
21	3,972	4.05%	87,852	89.67%
22	3,936	4.02%	91,788	93.68%
23	3,596	3.67%	95,384	97.35%
24	2,592	2.65%	97,976	100.00%

Table 2-95 shows that reductions under the Economic Program when zonal, load-weighted, average LMP was greater than, or equal to, $75 per MWh were generally higher in hours ended 1100 EPT through 2200 EPT, with the highest levels of activity in hours ended 1200 EPT through 2000 EPT.

Table 2-95 Frequency distribution of Economic Program hours with zonal, load-weighted, average LMP greater than, or equal to, $75 per MWh (By hours): Calendar year 2007

Hour	Frequency	Percent	Cumulative Frequency	Cumulative Percent
1	228	0.21%	228	0.21%
2	346	0.31%	574	0.52%
3	265	0.24%	839	0.76%
4	225	0.20%	1,064	0.97%
5	260	0.24%	1,324	1.20%
6	835	0.76%	2,159	1.96%
7	2,947	2.67%	5,106	4.63%
8	3,140	2.85%	8,246	7.48%
9	3,542	3.21%	11,788	10.69%
10	3,998	3.63%	15,786	14.32%
11	6,253	5.67%	22,039	19.99%
12	7,215	6.54%	29,254	26.53%
13	7,590	6.88%	36,844	33.42%
14	8,431	7.65%	45,275	41.07%
15	9,199	8.34%	54,474	49.41%
16	8,786	7.97%	63,260	57.38%
17	9,382	8.51%	72,642	65.89%
18	9,796	8.89%	82,438	74.77%
19	7,866	7.13%	90,304	81.91%
20	6,707	6.08%	97,011	87.99%
21	6,328	5.74%	103,339	93.73%
22	4,633	4.20%	107,972	97.93%
23	1,433	1.30%	109,405	99.23%
24	846	0.77%	110,251	100.00%

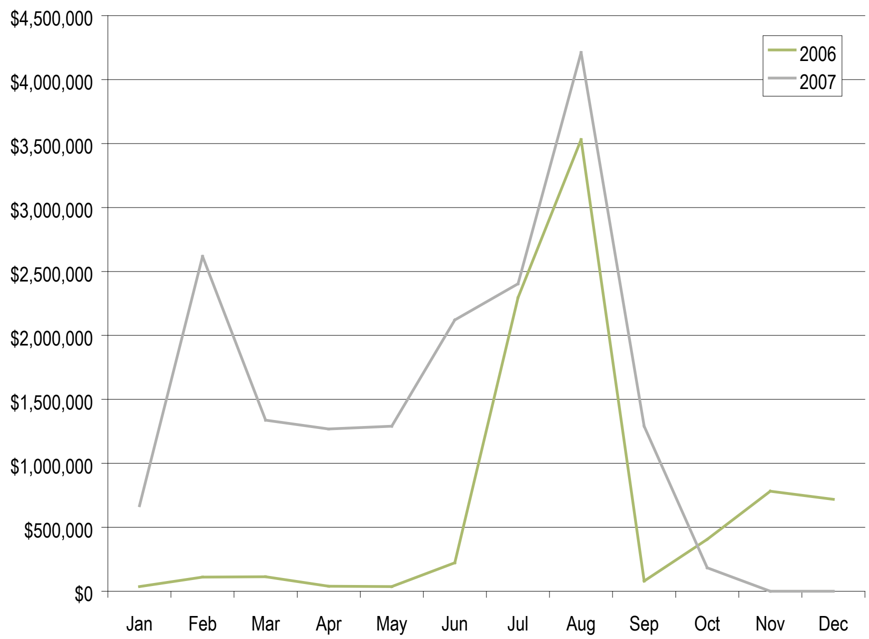
Table 2-96 shows the frequency distribution of Economic Program hourly reductions by real-time zonal, load-weighted, average LMP in price ranges of $15 per MWh. Activity occurred primarily when zonal, load-weighted, average LMP was between $15 and $135 per MWh. Most hours, 52.95 percent, during which reductions took place had zonal, load-weighted, average LMP greater than, or equal to, $75 per MWh.

Table 2-96 Frequency distribution of Economic Program zonal, load-weighted, average LMP (By hours): Calendar year 2007

LMP ($/MWh)	Frequency	Percent	Cumulative Frequency	Cumulative Percent
$0 to $15	12	0.01%	12	0.01%
$15 to $30	9,182	4.41%	9,194	4.42%
$30 to $45	22,368	10.74%	31,562	15.16%
$45 to $60	29,329	14.09%	60,891	29.24%
$60 to $75	37,085	17.81%	97,976	47.05%
$75 to $90	39,978	19.20%	137,954	66.25%
$90 to $105	26,655	12.80%	164,609	79.05%
$105 to $120	14,575	7.00%	179,184	86.05%
$120 to $135	8,999	4.32%	188,183	90.37%
$135 to $150	5,821	2.80%	194,004	93.17%
$150 to $165	3,998	1.92%	198,002	95.09%
$165 to $180	2,412	1.16%	200,414	96.25%
$180 to $195	1,786	0.86%	202,200	97.11%
$195 to $210	1,207	0.58%	203,407	97.69%
$210 to $225	1,070	0.51%	204,477	98.20%
$225 to $240	843	0.40%	205,320	98.60%
$240 to $255	667	0.32%	205,987	98.92%
$255 to $270	349	0.17%	206,336	99.09%
$270 to $285	213	0.10%	206,549	99.19%
$285 to $300	189	0.09%	206,738	99.28%
$300 to $315	171	0.08%	206,909	99.37%
$315 to $330	244	0.12%	207,153	99.48%
$330 to $345	116	0.06%	207,269	99.54%
$345 to $360	65	0.03%	207,334	99.57%
$360 to $375	71	0.03%	207,405	99.61%
$375 to $390	89	0.04%	207,494	99.65%
$390 to $405	19	0.01%	207,513	99.66%
$405 to $420	69	0.03%	207,582	99.69%
$420 to $435	19	0.01%	207,601	99.70%
$435 to $450	77	0.04%	207,678	99.74%
$450 to $465	41	0.02%	207,719	99.76%
$465 to $480	71	0.03%	207,790	99.79%
$480 to $495	153	0.07%	207,943	99.86%
$495 to $510	41	0.02%	207,984	99.88%
$510 to $525	2	0.00%	207,986	99.88%
$525 to $540	4	0.00%	207,990	99.89%
> $540	237	0.11%	208,227	100.00%

Figure 2-23 shows the monthly distribution of incentive payments for calendar years 2006 and 2007.[93] In 2007, substantial increases in incentive payments occurred throughout the year. Incentive payments reached a monthly maximum in August in both 2007 and 2006. On October 24, 2007, PJM issued the statement that the demand-side resources incentive cap of $17.5 had been reached.[94] PJM allocated $17 million of incentive payments and $500,000 was reserved for disputed settlements. As of December 31, 2007, the incentive payments totaled $17,391,099, an increase of 108 percent from calendar year 2006. No incentive credits were paid in November and December 2007.[95]

Figure 2-23 Incentive payments: Calendar years 2006 and 2007



93 When LMP is greater than, or equal to, $75 per MWh, customers are paid the full LMP, and the amount not paid by the LSE, equal to the generation and transmission components of the applicable retail rate (recoverable charges), is charged to all LSEs in the zone of the load reduction. If the total amount of recoverable charges reflecting the generation and transmission payments for the entire program exceeds $17.5 million in a year, participants will receive LMP less an amount equal to the applicable generation and transmission charges for the remainder of the year, regardless of the level of LMP. The incentive payments are included in Economic Program payments.

94 Letter from S. Covino to the PJM Members < http://www.pjm.com/committees/working-groups/dsrwg/postings/incentive-cap-reached.pdf> (9.58 KB).

95 Incentive payments for 2006 and 2007 for this report were confirmed by PJM's DSR department. These payments are subject to monthly settlement adjustments. The incentive payments for 2006 and 2007 are based on the January 2008, PJM billing information.

Active Load Management (ALM) and Load Management (LM)

Table 2-97 shows the available ALM MW for 2002 to 2006 and the available LM MW for 2007.

Table 2-97 Available ALM MW and LM MW: Within 2002 to 2007

	2002	2003	2004	2005	2006	2007
1-Jun	1,342	1,265	1,412	2,035	1,655	2,140
1-Jul	1,304	1,255	1,228	2,042	1,679	2,145
1-Aug	1,285	1,156	1,226	2,042	1,679	2,145
1-Sep	1,275	1,158	1,224	2,038	1,678	2,145

Price Impacts of Demand-Side Response

The price impact of demand-side response can be calculated in a number of ways. Prior to the *2006 State of the Market Report*, the MMU calculated the price impact using the aggregate summer PJM supply curve, as this represents the actual offers of PJM resources. However, the actual real-time prices in PJM reflect the fact that resources are not completely flexible and that the aggregate supply curve does not always reflect real-time limitations on the ability to dispatch available generation resources. In the 2006 and 2007 state of the market reports, real-time hourly supply curves were developed for summer hours from actual PJM prices and corresponding loads, which represent the relationship between prices and loads in PJM for this time period. This method is straightforward and reproducible by any market analyst. PJM hourly supply curves for the period from June to September 2007 were analyzed.

The analysis showed that a reduction of 1 MW resulted in a price reduction of between $0.0015 and $0.0016 per MW.

Measurement Issues

Customer Base Line (CBL)

There are significant issues with the current approach to measuring demand-side response MW, which is the basis on which program participants are paid. The current approach can lead to payments when the customer has taken no action to respond to market prices. A substantial improvement in measurement and verification methods must be implemented in order to ensure the credibility of PJM demand-side programs. The goal should be to treat the measurement of demand-side resources like the measurement of any other resource in the wholesale power market, including generation and load, that is paid by other participants or makes payments to other participants.

Under current DSR business rules, participants in the Economic Program can measure their reductions by comparing metered load against an estimate of what metered load would have been absent the reduction.[96] CBL calculations were intended to estimate "A set of days that will serve as representative of a retail

96 On-site generation meter data are the other method used to determine the load reduction, if used only for economic load reduction.

customer's typical usage."[97] Separate calculations are done for weekdays and weekends/holidays and customers can use weather sensitivity factors to adjust the CBL calculations, if desired.

The current weekday CBL methodology requires the selection of 10 weekdays and the five highest are used for the calculation. However, low usage days (load less than 75 percent of the average) and event days (days with curtailment events or demand reductions) are eliminated and replaced with prior days. There is currently no limit on the historical period that can be used to select the 10 days, called the CBL basis window. The high threshold for low usage days (75 percent) combined with no limitation on the historical period for the basis window can result in an inflated estimate of what metered load would have been absent the reduction.

Another issue with the existing measurement and verification rules is that there is no clear requirement that a customer had to take a verifiable step to reduce energy use in response to prices in order to receive payment under the program. This omission allows retail customers to submit activities like maintenance outages, equipment failures, storm outages, scheduled vacation shutdowns or plant closures as load reductions and receive payments. The DSR business rules should clearly define load curtailments and should exclude such activities from the CBL window calculations.

The electricity distribution company (EDC) or LSE is responsible for reviewing a customer's CBL data and may object to the calculations. When an EDC or LSE objects, customers have time to resubmit the data, which are also subject to review. In 2006, there were multiple settlement disputes in which an EDC or LSE did not approve CBL calculations, and customers requested PJM involvement.

The Customer Base Line Subcommittee was created in January 2007. The subcommittee's mission was to "Evaluate current methodology for PJM economic load response used to determine load reductions done through deliberate customer actions in response to expected day ahead and/or real time prices…[and] propose enhancements and/or changes that will improve the transparency and accuracy of the results which will also help to reduce the number of unanticipated settlement rejections."[98]

In December 2007, proposals to modify CBL business rules were presented to the Market Implementation Committee with focus on two major issues: the permissible period for selecting a comparable day and number of days to be used for the CBL calculation and the definition of a demand-side curtailment.

Accurate measurement and verification is essential to ensuring that the Economic Program achieves its objectives and achieves its goal of paying for actual resource savings rather than paying for phantom savings. Any measurement and verification protocol based on broad average usage levels will be inaccurate at least part of the time. That is why, when a payment is contested, PJM and the MMU must have the explicit authority to apply more detailed measurement techniques to verify claimed usage reductions and to ensure that no payments are made in the absence of verifiable reductions.

97 OA, Original Sheet No. 119A, Effective February 24, 2006.

98 "Customer Baseline Committee Charter," February 27, 2007, <http://www.pjm.com/ committees/subcommittee/cbls/postings/20070223-final-charter.pdf> (22.7 KB).

SECTION 3 – ENERGY MARKET, PART 2

The PJM Market Monitoring Unit (MMU) analyzed measures of PJM Energy Market structure, participant conduct and market performance for 2007.[1] 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.

Overview

Net Revenue

- Net Revenue Adequacy. Net revenue is an indicator of generation investment profitability and thus is a measure of overall market performance as well as a measure of the incentive to invest in new generation to serve PJM markets. Net revenue quantifies the contribution to capital cost received by generators from 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.

  Overall, 2007 net revenue showed a significant increase over 2006. This was the result of higher prices in both the Energy and Capacity Markets. The levels of net revenue in 2007 for new peaking, midmerit and coal-fired baseload vary significantly by location. The fixed costs of constructing a new entrant combustion turbine, combined-cycle or coal-fired steam generation resource were fully covered in some, but not all, PJM control zones. There was revenue adequacy in 2007 for the combined-cycle (CC) technology for more zones than for either the combustion turbine (CT) or pulverized-coal (CP) technologies. Revenues associated with the sale of capacity resources increased significantly in 2007 as the result of the introduction of the Reliability Pricing Model (RPM) construct. The results from 2007 mark a reversal of the trend from the prior eight-year period, 1999 to 2006. The increased net revenues in 2007 were the result of higher locational energy prices and of much higher locational capacity prices.[2]

  Zonal net revenue reflects differences in locational energy prices and differences in locational capacity prices. The zonal variation in net revenue illustrates the substantial impact of location on economic incentives. While the 2007 net revenue using PJM real-time average locational marginal prices (LMPs) was $48,530 per MW-year for a CT, the zonal maximum net revenue was $96,913 in the Pepco Control Zone and the minimum was $16,047 in the DAY Control Zone.[3] While the PJM average net revenue in

1 As part of this analysis, the Market Monitoring Unit (MMU) compared the market results in 2007 to those of 2006 and certain other prior years. During calendar years 2004 and 2005, PJM conducted the phased integration of five control zones: ComEd, American Electric Power (AEP), The Dayton Power & Light Company (DAY), Duquesne Light Company (DLCO) and Dominion. By convention, control zones bear the name of a large utility service provider working within their boundaries. The nomenclature applies to the geographic area, not to any single company. For additional information on the integrations, their timing and their impact on the footprint of the PJM service territory, see the *2007 State of the Market Report*, Volume II, Appendix A, "PJM Geography."

2 For the eight-year period 1999 to 2006, capacity revenues were lower than during 2007 and generally decreasing with the exception of 2001 when market power issues affected prices.

3 Calculated values shown in Section 3, "Energy Market, Part 2," are based on unrounded, underlying data and may differ from calculations based on the rounded values shown in tables.

2007 was $100,809 per MW-year for a CC, the zonal maximum net revenue was $175,698 in the Pepco Control Zone and the minimum was $41,958 in the AEP Control Zone. While the PJM average net revenue in 2007 was $277,284 per MW-year for a CP, the zonal maximum net revenue was $384,940 in the Pepco Control Zone and the minimum was $157,544 in the DLCO Control Zone.

Existing and Planned Generation

- PJM Installed Capacity. During the period January 1, through December 31, 2007, PJM installed capacity remained relatively flat. Retirements were offset by new additions and the installed capacity on December 31, 2007, was only 658 MW more than on January 1, 2007.

- PJM Installed Capacity by Fuel Type. At the end of 2007, PJM installed capacity was 163,498 MW. Of the total installed capacity, 40.5 percent was coal; 29.1 percent was natural gas; 18.9 percent was nuclear; 6.5 percent was oil; 4.5 percent was hydroelectric; and 0.4 percent was solid waste.

- Generation Fuel Mix. During 2007, coal provided 55.3 percent, nuclear 33.9 percent, natural gas 7.7 percent, oil 0.5 percent, hydroelectric 1.7 percent, solid waste 0.7 percent and wind 0.2 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. There were 157 hours of high load that occurred in 2007, of which 21 occurred in June, 40 occurred in July and 96 occurred in August. This number of high-load hours is more than twice the 70 high-load hours in 2006. Within these 157 hours, there were three hours, the hours beginning 1500 through 1700, on August 8 that met the criteria for potential within-hour scarcity.[4] PJM triggered its scarcity pricing events between 1505 and 1812. This represents a clear improvement over 2006 when 10 hours met the criteria for potential within-hour scarcity while no scarcity events were triggered.

- Scarcity Pricing Events in 2007. 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. PJM implemented administratively based, scarcity pricing rules in 2006.[5] Based on the definition of scarcity in the Tariff, there were two official scarcity pricing events on August 8, 2007: one in the Bedington — Black Oak Scarcity Pricing Zone between 1505 and 1812 and the other in the Mid-Atlantic Scarcity Pricing Region between 1555 and 1733.

4 Scarcity is considered to exist when hourly demand, including a total operating reserve requirement, is greater than, or equal to, total, within-hour supply in the absence of non market administrative intervention.

5 114 FERC ¶ 61,076 (2006).

- Modifications to Scarcity Pricing. While PJM's triggers for administrative scarcity pricing are reasonable measures of scarcity conditions, there are indications, based on the MMU analysis of 2007 market results, that PJM's current set of scarcity pricing rules need refinement. In addition, PJM should consider creating a mechanism for defining new scarcity pricing regions in real time if system conditions warrant. The MMU reviewed the summer of 2007 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 stages of scarcity, each with an associated administrative price, rather than the single step now in the Tariff. PJM should also consider adding new scarcity pricing regions. There would have been six hours of scarcity under PJM rules if BGE and Pepco had been defined to be a scarcity region. In addition, the actual market signal needs further refinement. The single scarcity price signal should be replaced by locational signals. Locational signals could be implemented via scarcity offers submitted by generation owners. This would provide a means to signal scarcity that is consistent with economic dispatch, consistent with locational pricing and consistent with competitive market outcomes. Combined with a more refined set of scarcity triggers, this approach would also encourage participants to offer competitively under normal market conditions and competitively in the context of scarcity conditions.

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 2007. The level of operating reserve credits and corresponding charges increased in 2007 by 42.45 percent compared to 2006. The amount of balancing operating reserve credits paid to synchronous condensing increased by 176.79 percent compared to 2006, 17.49 percent of the total net increase.

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-requirement 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.

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. A capacity market is an explicit mechanism for valuing capacity and is preferable to non market and nontransparent mechanisms for that reason.

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 had 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 have not been fully synchronized.

The historical 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.

PJM's RPM is an explicit 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 combination of locational Energy Market and locational Capacity Market signals in 2007 represented a significant change from market performance over prior years. The combined locational prices clearly signaled a need for and an incentive for investment in eastern zones where there is a demonstrated need for new capacity, although the results vary by technology. Net revenues exceeded the costs of all technologies in the BGE and Pepco Control Zones and net revenues exceeded the costs of CC technology in seven eastern control zones.

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 Real-Time Energy Market, the Day-Ahead Energy Market and the Capacity Market prior to 2007 illustrated that additional market modifications were necessary if PJM were to pass that test. The performance of the markets in 2007, especially the Capacity Markets, represented a significant improvement over prior performance. The reaction of investors will determine whether the market design modifications are successful.

Net Revenue

Net revenue is an indicator of generation investment profitability, and thus is a measure of overall market performance as well as a measure of the incentive to invest in new generation to serve PJM markets. Net revenue quantifies the contribution to capital cost received by generators from PJM Energy, Capacity and Ancillary Service Markets and from the provision of black start and reactive services. Although generators receive operating reserve payments as a revenue stream, these payments are not included when the analysis is based on perfect dispatch.[6] Operating reserve payments are included, when the analysis is based on the peak-hour, economic dispatch model on any days when a unit operated at a loss.[7]

Gross Energy Market revenue is the product of the Energy Market price and generation output. Gross revenues are also received from the Capacity and Ancillary Service Markets. Total gross revenue less variable cost equals net revenue. In other words, net revenue is the amount that remains, after variable costs have been subtracted from gross revenue, to cover fixed costs which include a return on investment, depreciation, taxes and fixed operation and maintenance expenses.

The net revenues presented in this section are theoretical as they are based on explicitly stated assumptions about how a unit would operate, rather than on an analysis of actual net revenues for actual units operating in PJM. Energy Market net revenues were developed separately for both the Real-Time and the Day-Ahead Energy Markets.

6 Under the PJM model, operating reserve payments compensate generation owners when units operate at PJM's request when LMP is less than marginal cost over the day of operation. Operating reserve does not apply in perfect dispatch because the theoretical unit only operates when LMP is greater than marginal cost.

7 The peak-hour, economic dispatch model is a realistic simulation of market outcomes that, in contrast to the perfect dispatch model, considers applicable constraints faced by PJM dispatchers. There are instances in the model when a unit is dispatched for a block that yields negative net energy revenue and, consistent with actual PJM operating practices, is made whole by operating reserve payments.

In a perfectly competitive, energy-only market in long-run equilibrium, net revenue from the energy market would be expected to equal the total of all fixed costs for the marginal unit, including a competitive return on investment. The PJM market design includes other markets intended to contribute to the payment of fixed costs. In PJM, the Energy, Capacity and Ancillary Service Markets are all significant sources of revenue to cover fixed costs of generators, as are payments for the provision of black start and reactive services. Thus, in a perfectly competitive market in long-run equilibrium, with energy, capacity and ancillary service payments, net revenue from all sources would be expected to equal the fixed costs of generation for the marginal unit. Net revenue is a measure of whether generators are receiving competitive returns on invested capital and of whether market prices are high enough to encourage entry of new capacity. In actual wholesale power markets, where equilibrium seldom occurs, net revenue is expected to fluctuate based on actual conditions in all relevant markets.

Theoretical Energy Market Net Revenue

The Real-Time Energy Market revenues in Table 3-1 and the Day-Ahead Energy Market revenues in Table 3-2 reflect net Energy Market revenues from all hours during 1999 to 2007 for the Real-Time Energy Market and during 2000 to 2007 for the Day-Ahead Energy Market when the PJM hourly LMP exceeded the identified marginal cost of generation. The tables include the dollars per installed MW-year that would have been received by a unit in PJM if it had operated whenever system price exceeded the identified marginal cost in dollars per MWh, adjusted for unit forced outages.[8] For example, during 2007, if a unit had marginal costs (i.e., fuel plus variable operation and maintenance expense) equal to $30 per MWh, it had an incentive to operate whenever the Real-Time Energy Market LMP exceeded $30 per MWh. If such a unit had operated during all profitable hours in 2007, adjusted for forced outages, it would have received $235,215 per installed MW-year in net revenue from the Real-Time Energy Market alone. For the Day-Ahead Energy Market, the same unit would have received $207,702 per installed MW-year in net revenue from the Day-Ahead Energy Market.[9]

Table 3-1 illustrates the relationship between generator marginal cost and net revenue from the PJM Real-Time Energy Market alone for the years 1999 through 2007.

8 Real-Time and Day-Ahead Energy Market net revenue calculations reflect a forced outage rate equal to the actual PJM system forced outage rate for each year. Since these tables include a range of marginal cost from $10 to $200, an outage rate by class cannot be utilized because there is no simple mapping of marginal cost to class of generation; i.e., the $100 range could include steam-oil, gas–fired CC and efficient gas-fired CTs. Class-specific forced outage rates are used for the class-specific net revenue calculations.

9 This unit would not receive Real-Time Energy Market revenues in addition to Day-Ahead Energy Market revenues as any energy scheduled in the Day-Ahead Energy Market would be credited at the day-ahead energy market-clearing price and would not be eligible for Real-Time Energy Market revenues for that same hour of operation.

Table 3-1 PJM Real-Time Energy Market net revenue (By unit marginal cost (Dollars per MWh)): Calendar years 1999 to 2007

Marginal Cost	1999	2000	2001	2002	2003	2004	2005	2006	2007
$10	$152,087	$150,774	$186,887	$153,620	$231,927	$263,115	$394,619	$322,668	$388,984
$20	$94,690	$89,418	$116,116	$85,661	$159,751	$185,956	$314,917	$242,179	$308,397
$30	$72,489	$59,776	$78,368	$51,898	$110,126	$121,218	$241,977	$171,735	$235,215
$40	$62,367	$39,519	$56,055	$31,650	$73,828	$74,920	$184,479	$120,014	$177,918
$50	$57,080	$25,752	$42,006	$19,776	$47,277	$44,577	$141,078	$83,857	$132,033
$60	$54,132	$16,888	$33,340	$13,101	$29,566	$25,328	$107,057	$58,812	$95,768
$70	$52,259	$11,750	$27,926	$9,080	$18,001	$13,624	$80,473	$41,608	$67,644
$80	$50,959	$8,586	$24,389	$6,623	$10,650	$6,929	$59,903	$29,643	$46,859
$90	$49,840	$6,700	$22,080	$5,079	$6,273	$3,494	$44,043	$21,585	$32,467
$100	$48,818	$5,640	$20,521	$4,109	$3,770	$1,784	$32,184	$16,188	$23,110
$110	$47,863	$4,930	$19,375	$3,507	$2,250	$951	$23,338	$12,653	$16,898
$120	$46,926	$4,385	$18,480	$3,063	$1,315	$518	$16,831	$10,283	$12,655
$130	$46,007	$3,958	$17,716	$2,758	$723	$260	$12,070	$8,645	$9,795
$140	$45,114	$3,609	$17,030	$2,501	$387	$124	$8,528	$7,466	$7,737
$150	$44,228	$3,317	$16,421	$2,287	$218	$51	$5,903	$6,667	$6,302
$160	$43,374	$3,102	$15,884	$2,115	$142	$24	$3,946	$6,030	$5,202
$170	$42,523	$2,923	$15,395	$1,970	$94	$9	$2,554	$5,508	$4,357
$180	$41,685	$2,768	$14,944	$1,828	$51	$0	$1,679	$5,083	$3,722
$190	$40,856	$2,623	$14,542	$1,700	$23	$0	$1,113	$4,699	$3,219
$200	$40,036	$2,488	$14,162	$1,607	$10	$0	$706	$4,347	$2,831

Table 3-2 illustrates the relationship between generator marginal cost and net revenue from the PJM Day-Ahead Energy Market alone for the years 2000 through 2007.[10]

Table 3-2 PJM Day-Ahead Energy Market net revenue (By unit marginal cost (Dollars per MWh)): Calendar years 2000 to 2007

Marginal Cost	2000	2001	2002	2003	2004	2005	2006	2007
$10	$158,429	$189,366	$154,267	$234,622	$254,455	$392,425	$216,637	$364,734
$20	$95,823	$115,372	$83,083	$159,572	$176,265	$311,563	$165,614	$283,295
$30	$61,816	$68,718	$44,916	$102,907	$109,583	$235,006	$117,447	$207,702
$40	$38,762	$42,283	$25,011	$61,674	$59,650	$173,084	$77,340	$146,320
$50	$23,141	$27,936	$15,126	$34,891	$27,638	$125,929	$47,954	$97,297
$60	$14,281	$20,375	$9,894	$19,169	$11,152	$90,176	$29,201	$59,674
$70	$9,523	$16,304	$6,804	$10,504	$4,039	$63,340	$18,423	$34,135
$80	$6,840	$13,933	$4,856	$5,858	$1,375	$43,467	$12,613	$19,326
$90	$5,100	$12,540	$3,522	$3,389	$415	$29,224	$9,180	$11,257
$100	$3,927	$11,478	$2,570	$1,954	$121	$19,208	$7,037	$6,530
$110	$3,244	$10,705	$1,885	$1,150	$42	$12,186	$5,742	$3,730
$120	$2,683	$10,098	$1,385	$620	$14	$7,409	$4,873	$2,081
$130	$2,299	$9,579	$1,000	$315	$0	$4,361	$4,203	$1,167
$140	$2,056	$9,139	$712	$148	$0	$2,397	$3,628	$703
$150	$1,884	$8,708	$494	$34	$0	$1,229	$3,136	$421
$160	$1,787	$8,312	$354	$0	$0	$574	$2,703	$241
$170	$1,701	$7,926	$243	$0	$0	$234	$2,314	$118
$180	$1,616	$7,564	$145	$0	$0	$83	$1,991	$51
$190	$1,532	$7,232	$78	$0	$0	$31	$1,717	$11
$200	$1,447	$6,908	$30	$0	$0	$11	$1,475	$0

Figure 3-1 displays the information from Table 3-1, and Figure 3-2 displays the information from Table 3-2. As Figure 3-1 illustrates, the Real-Time Energy Market net revenue curve was higher in 2007 than in 2006 for every level of unit marginal costs up to and including $140 per MWh. For units with marginal costs equal to, or less than, $70, net revenues were higher in 2007 than in any other year, except 2005, since PJM introduced markets in 1999. As Figure 3-2 illustrates, the Day-Ahead Energy Market net revenue curve was higher in 2007 than in 2006 for every marginal cost level up to and including $90. For units with marginal costs equal to, or less than, $80, net revenues were higher in 2007 than in any other year except 2005, since PJM introduced the Day-Ahead Energy Market in 2000.

The increase in 2007 Real-Time Energy Market net revenue compared to 2006 is the result of changes in the frequency distribution of energy prices. In 2007, prices were greater than, or equal to, $30 per MWh

10 The Day-Ahead Energy Market began on June 1, 2000. For the analysis presented in Table 3-2, Real-Time Energy Market LMP was used from January 1, 2000, to May 31, 2000.

more frequently than in 2006 yet less frequently compared to 2005. The 2007 simple average LMP was $57.58 per MWh, a substantial increase compared to $49.27 per MWh in 2006 and just below the 2005 simple average of $58.08 per MWh. This explains why 2007 Energy Market net revenue falls between 2005 and 2006 for most marginal cost levels. In 1999, the Real-Time Energy Market LMP was greater than, or equal to, $30 per MWh during 17 percent of all hours. In 2000, this was 29 percent; in 2001, 34 percent; in 2002, 30 percent; in 2003, 51 percent; in 2004, 68 percent; 81 percent in 2005; 74 percent in 2006 and 79 percent in 2007.

The increase in 2007 as compared to 2006 Day-Ahead Energy Market net revenue is also the result of changes in the frequency distribution of energy prices. In 2007, prices were greater than, or equal to, $30 more frequently than in 2006 as the 2007 simple average LMP was $54.67 per MWh in 2007 compared to $48.10 per MWh in 2006 and $57.89 per MWh in 2005. In 2000, the Day-Ahead Energy Market LMP was greater than or equal to $30 per MWh during 42 percent of all hours. In 2001, this was 42 percent; in 2002, 33 percent; in 2003, 60 percent; in 2004, 72 percent; in 2005, 86 percent; in 2006, 80 percent and in 2007, 84 percent.

The distribution of prices reflects a number of factors including load levels and fuel costs. An efficient CT could have produced energy at an average cost of $30 in 1999, but $90 in 2007. An efficient CC could have produced energy at an average cost of $20 in 1999, but $55 in 2007. An efficient CP could have produced energy at an average cost of $20 in 1999, but $25 in 2007. Average price levels in 2007 were slightly lower than in 2005 and, as a result, net revenue levels were lower for specific marginal cost levels, as shown in Figure 3-1 and Figure 3-2. Nonetheless, Energy Market net revenues for a new entrant CT, CC and CP were significantly higher in 2007 than in 2005 because the average delivered price of natural gas was about 19 percent lower in 2007 than in 2005. From 2005 to 2006, natural gas prices dropped, as did PJM price levels. From 2006 to 2007, average PJM prices increased at a faster rate than did natural gas prices. The result is that average PJM prices in 2007 were very close to what they were in 2005, while natural gas-fired units experienced much lower marginal costs compared to 2005, meaning higher net revenue in 2007.

Figure 3-1 PJM Real-Time Energy Market net revenue (By unit marginal cost): Calendar years 1999 to 2007

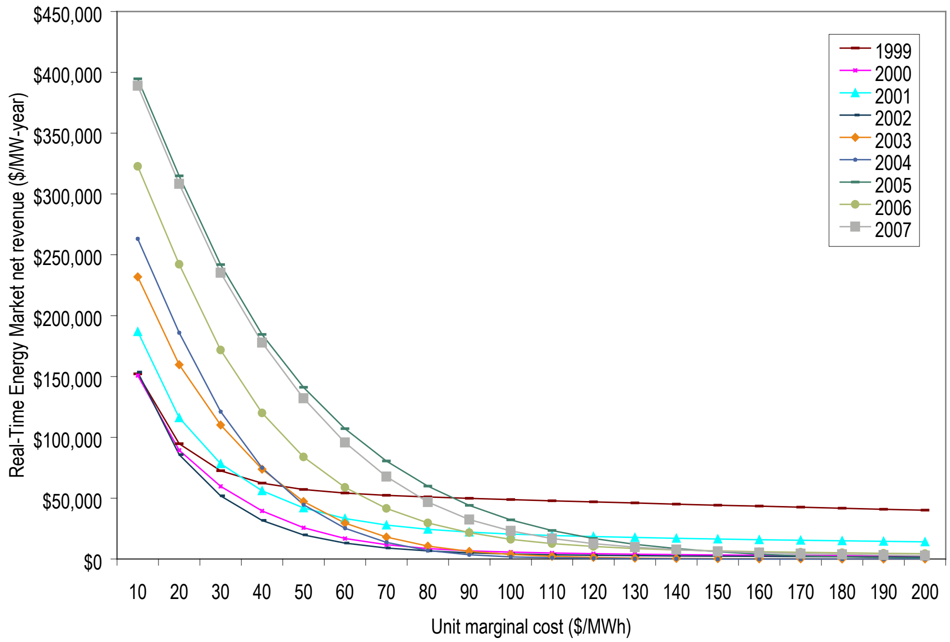
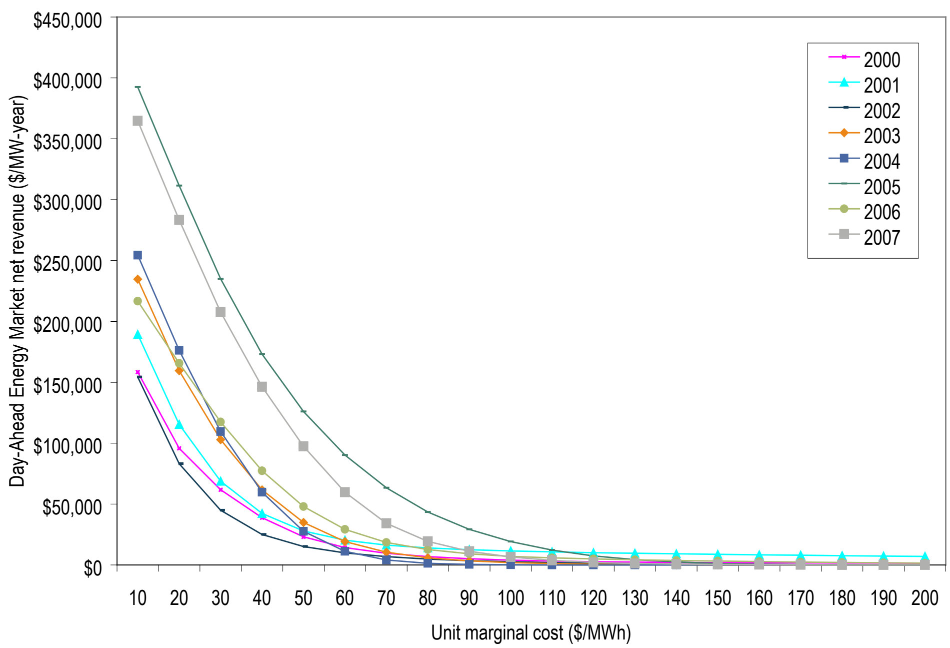


Figure 3-2 PJM Day-Ahead Energy Market net revenue (By unit marginal cost): Calendar years 2000 to 2007



Differences in the shape and position of Real-Time and Day-Ahead Energy Market net revenue curves result from different distributions of Energy Market prices in each year. These differences illustrate, among other things, the significance of a relatively small number of high-priced hours to the profitability of high marginal cost units.[11]

The theoretical net revenues displayed in Table 3-1 and Table 3-2 are calculated under perfect dispatch assumptions and, as such, represent an upper bound of the markets' direct contribution to generator fixed costs. All things constant, these Energy Market net revenues show how the frequency distribution of price levels in a given year affects the amount of revenue a generator would have received at the specified levels of marginal cost.

The Energy Market net revenues shown in Table 3-1 and Table 3-2 do not consider operating constraints that may affect actual net revenue of an individual plant. Such operating constraints are less likely to affect the net revenue calculations for CTs, given their operational flexibility and the operating reserve revenue guarantee. For a CC steam plant, a two-hour hot status notification plus startup time for a summer weekday could prevent a unit from running during two positive net revenue hours in the afternoon peak and two more positive net revenue hours in the evening peak separated by two negative net revenue hours, or could result in reduced net revenues from the negative net revenue hours.[12] The actual impact depends on the relationship between LMP and the operating cost of the unit. Similarly, a CP steam plant with an eight-hour cold status notification plus startup time could run overnight during negative net revenue hours although the lower relative operating costs of a steam unit would generally reduce the significance of the issue.[13] Ramp limitations might prevent a CC or steam unit from starting and ramping up to full output in time to operate for all positive net revenue hours.

Conversely, the net revenue measure does not include the potentially significant contribution to fixed cost from the explicit or implicit sale of the option value of physical units or from bilateral agreements to sell output at a price other than the PJM Day-Ahead or Real-Time Energy Market prices, e.g., a forward price.

Capacity Market Net Revenue

Generators receive revenue from the sale of capacity in addition to revenue from the Energy and Ancillary Service Markets. In the PJM market design, the sale of capacity provides an important source of revenues to cover generator fixed costs. The Capacity Credit Market (CCM) design was in effect until June 1, 2007. For the period from January 1, through May 31, 2007, PJM capacity resources received a weighted-average payment from the CCM of $3.21 per MW-day of unforced capacity, a total of $485 per MW for the five-month period, or $1,172 per MW-year on an annualized basis. This is the lowest level of CCM revenues since the opening of the CCM in mid-1999.

On June 1, 2007, with the implementation of the RPM, PJM capacity resources began to receive a daily capacity payment of an amount determined by the first RPM Auction (June 1, 2007, through May 31, 2008) for their corresponding locational delivery area (LDA). For the first RPM Auction, there were three LDAs with

11 See the *2007 State of the Market Report*, Volume II, Section 2, "Energy Market, Part 1," at "Load and LMP" and Appendix C, "Energy Market" for detailed data on prices and their annual distribution.

12 A two-hour hot start, including a notification period, is consistent with the CC technology.

13 An eight-hour cold status notification plus startup is consistent with the CP technology.

three separate prices: RTO, which cleared at $40.80 per MW-day or $8,731 per MW for the remainder of calendar year 2007 or $14,892 per MW-year on an annualized basis; Eastern Mid-Atlantic Area Council (EMAAC), which cleared at $197.67 per MW-day or $42,301 for the remainder of 2007 and $72,150 per MW-year on an annualized basis; and Southwestern Mid-Atlantic Area Council (SWMAAC), which cleared at $188.54 per MW-day or $40,348 for the remainder of 2007 and $68,817 per MW-year on an annualized basis.

The 2007 zonal RPM prices, in effect from June 1, through December 31, 2007, are presented in Table 3-3 along with corresponding PJM control zones.

Table 3-3 PJM RPM auction-clearing capacity price by LDA: Effective for June 1, through December 31, 2007

LDA	$/MW-Day	$/MW in 2007 (7-Month)	PJM Zones Associated
RTO	$40.80	$8,731	AEP, ComEd, AP, Met-Ed, PENELEC, PPL, DLCO, DAY, Dominion
EMAAC	$197.67	$42,301	PSEG, PECO, RECO, AECO, DPL, JCPL
SWMAAC	$188.54	$40,348	Pepco, BGE

Table 3-4 shows capacity revenue for the nine-year period 1999 to 2007.[14] Results for 1999 through 2006 reflect the load-weighted averages from the CCM construct. Results for 2007 combine the CCM values for the January through May period and the RPM Auction values for the June through December period. In Table 3-4, the 2007 column represents an average of all revenue associated with the sale of capacity by zone followed by a weighted-average of capacity revenue for the PJM footprint. The zonal results combine load-weighted averages from both daily and monthly CCM prices for January through May as well as the associated LDA-clearing price from Table 3-3 for the remaining seven months.[15] These capacity revenues are adjusted for the yearly, systemwide forced outage rate.[16]

14 In tables with zonal net revenues, data for a transmission zone are displayed for all full calendar years following integration into PJM markets.

15 The 2007 total revenue associated with capacity for PJM in Table 3-4 similarly combines load-weighted CCM and RPM revenues. The RPM revenue in this calculation is a load-weighted average based on all the LDA-clearing prices in Table 3-3 and the MW associated with each. The result is a load-weighted, average revenue associated with the sale of capacity per MW-year throughout the PJM footprint, not exclusively the RTO LDA.

16 The PJM capacity revenues presented in Table 3-4 differ slightly from those presented in Table 3-10, Table 3-12 and Table 3-14 as capacity revenues by technology type are adjusted for technology-specific outage rates.

Table 3-4 Capacity revenue by PJM zones (Dollars per MW-year): Calendar years 1999 to 2007

Zone	1999	2000	2001	2002	2003	2004	2005	2006	2007	Average
AECO	$18,124	$20,804	$32,981	$11,600	$5,946	$6,493	$2,089	$1,958	$39,680	$15,520
AEP	NA	NA	NA	NA	NA	NA	$2,089	$1,958	$8,551	$4,199
AP	NA	NA	NA	NA	$7,633	$6,493	$2,089	$1,958	$8,551	$5,345
BGE	$18,124	$20,804	$32,981	$11,600	$5,946	$6,493	$2,089	$1,958	$37,868	$15,318
ComEd	NA	NA	NA	NA	NA	NA	$3,607	$1,958	$8,551	$4,706
DAY	NA	NA	NA	NA	NA	NA	$2,089	$1,958	$8,551	$4,199
Dominion	NA	NA	NA	NA	NA	NA	NA	$1,958	$8,551	$5,255
DPL	$18,124	$20,804	$32,981	$11,600	$5,946	$6,493	$2,089	$1,958	$39,680	$15,520
DLCO	NA	NA	NA	NA	NA	NA	$2,089	$1,958	$8,551	$4,199
JCPL	$18,124	$20,804	$32,981	$11,600	$5,946	$6,493	$2,089	$1,958	$39,680	$15,520
Met-Ed	$18,124	$20,804	$32,981	$11,600	$5,946	$6,493	$2,089	$1,958	$8,551	$12,061
PECO	$18,124	$20,804	$32,981	$11,600	$5,946	$6,493	$2,089	$1,958	$39,680	$15,520
PENELEC	$18,124	$20,804	$32,981	$11,600	$5,946	$6,493	$2,089	$1,958	$8,551	$12,061
Pepco	$18,124	$20,804	$32,981	$11,600	$5,946	$6,493	$2,089	$1,958	$37,868	$15,318
PPL	$18,124	$20,804	$32,981	$11,600	$5,946	$6,493	$2,089	$1,958	$8,551	$12,061
PSEG	$18,124	$20,804	$32,981	$11,600	$5,946	$6,493	$2,089	$1,958	$39,680	$15,520
RECO	NA	NA	NA	NA	$5,946	$6,493	$2,089	$1,958	$39,680	$11,233
PJM	$18,124	$20,804	$32,981	$11,600	$5,946	$6,493	$2,089	$1,958	$29,966	$14,440

Ancillary Service and Operating Reserve Net Revenue

In addition to Capacity and Energy Market revenues, generators can receive revenue from the sale of ancillary services, including those from the Synchronized Reserve and Regulation Markets as well as from black start and reactive services. Aggregate ancillary service revenues, displayed for years 1999 through 2007 in Table 3-5, were $4,284 per installed MW-year in 2007. While actual, generator-specific ancillary service revenues vary with generator technology, ancillary service revenues are expressed here in terms of a system average per installed MW. New entrant net revenue calculations, addressed later in this section, use more detailed, technology-specific ancillary service estimates.

Table 3-5 System average ancillary service revenue: Calendar years 1999 to 2007

	Dollars per Installed MW-Year
1999	$3,444
2000	$4,509
2001	$3,831
2002	$3,500
2003	$3,986
2004	$3,667
2005	$5,135
2006	$3,926
2007	$4,284

Generators also receive operating reserve revenues from both the Day-Ahead and Real-Time Energy Markets. Operating reserve payments were about $1,600 per installed MW-year in 2006 and were about $2,000 per installed MW-year in 2007. These payments are designed, in part, to ensure that generators are paid enough to cover their offers, including startup and no-load costs, when scheduled by PJM so that they are not required to run at a loss.

New Entrant Net Revenues

In order to provide a more realistic estimate of the net revenues that would result from investment in new generation resources, a peak-hour, economic dispatch scenario was analyzed. In contrast to the perfect dispatch scenario, economic dispatch assumes realistic, technology-specific operating constraints in order to provide a more accurate calculation of a new entrant's operations and potential net revenue in PJM markets. All technology-specific, zonal net revenue calculations included in the new entrant net revenue analysis discussed in this section are based on the economic dispatch scenario.

Analysis of both the Real-Time and Day-Ahead Energy Market net revenues available for a new entrant includes three power plant configurations: a natural gas-fired CT, a two-on-one, natural gas-fired CC and a conventional CP, single reheat steam generation plant. The CT plant consists of two GE Frame 7FA CTs, equipped with full inlet air mechanical refrigeration and selective catalytic reduction (SCR) for NO_x reduction. The CC plant consists of two GE Frame 7FA CTs equipped with evaporative cooling, a single heat recovery steam generator (HRSG) for each CT with steam reheat and SCR for NO_x reduction with a single steam turbine generator. The coal plant is a western Pennsylvania seam CP, equipped with lime injection for SO_2 reduction and low NO_x burners in conjunction with over fire air for NO_x control.

All net revenue calculations include the use of actual hourly ambient air temperature[17] and river water cooling temperature[18] and the effect of each, as applicable, on plant heat rates[19] and generator output for each of the three plant configurations.[20] Plant heat rates were calculated for each hour to account for the efficiency changes and corresponding cost changes resulting from ambient air and river condition variations.[21] The effect of ambient air conditions and river water temperature on plant generation capability was calculated hourly to adjust for changes in energy production. For purposes of determining the amount of capacity that could be offered in the PJM Capacity Markets, the available capacity of each plant type was calculated based on actual ambient conditions at the hour of each annual peak load, consistent with PJM rules for determining available capacity. Available capacity was then adjusted downward by the actual class average forced outage rate for each generator type in order to obtain the level of unforced capacity available for sale in PJM's CCM for the months January through May and in the first RPM Auction for the months June through December.

NO_x and SO_2 emission allowance costs are included in the hourly plant dispatch cost, where applicable. These costs are included in the PJM definition of marginal cost. NO_x and SO_2 emission allowance costs were obtained from actual historical daily spot cash prices.[22] NO_x emission allowance costs were included only during the annual NO_x attainment period from May 1 through September 30. SO_2 emission allowance costs were calculated for every hour of the year.

A forced outage rate for each class of plant was calculated from PJM data.[23] This class-specific outage rate was then incorporated into all revenue calculations. Additionally, each plant was given a 15-continuous-day, planned, annual outage in the fall season.

Variable operation and maintenance (VOM) expenses were estimated to be $6.47 per MWh for the CT plant, $2.00 per MWh for the CC plant and $2.67 per MWh for the CP plant. These estimates were provided by a consultant to PJM and are based on quoted, third-party contract prices.[24] The VOM expenses for the CT and CC plants include accrual of anticipated, routine major overhaul expenses.[25] The burner tip fuel cost for natural gas is from published commodity daily cash prices, with a basis adjustment for transportation costs.[26] Coal burner tip cost was developed from the published prompt-month price, adjusted for rail transportation cost.[27] The average burner tip fuel prices are shown in Table 3-6.

Real-time ancillary service revenues for the provision of synchronized reserve service for all three plant types are set to zero. GE Frame 7FA CTs are typically not configured to provide Tier 2 synchronized reserve in

17 Hourly ambient conditions supplied by Meteorlogix from the Philadelphia International Airport, Philadelphia, Pennsylvania.

18 Hourly river water conditions represent the Reedy Island Jetty Gauge station located on the Delaware River. Data obtained from U.S. Department of the Interior, U.S. Geological Survey <http://nwis.waterdata.usgs.gov/pa/nwis/qwdata?site_no=01482800>.

19 These heat rate changes were calculated by Pasteris Energy, Inc., a consultant to the MMU, utilizing GE Energy's GateCycle Power Plant and Simulation Software. Neither GE Energy nor GE has reviewed this report or the calculations and results of the work done by Pasteris Energy, Inc. for PJM.

20 Pasteris Energy, Inc.

21 All heat rate calculations are expressed in Btu per net kWh. No-load costs are included in the heat rate and subsequently the dispatch price since each unit type is dispatched at full load for every economic hour, but is off for every uneconomic hour; therefore, there is a single offer point and no offer curve.

22 NO_x and SO_2 emission daily prompt prices obtained from Evolution Markets, Inc.

23 Outage figures obtained from the PJM eGADS database.

24 Pasteris Energy, Inc.

25 Routine combustor inspection, hot gas path and major inspection costs collected through the VOM adder. This figure was established by Pasteris Energy, Inc. and compares favorably with actual operation and maintenance costs from similar PJM generating units.

26 Gas daily cash prices obtained from Platts.

27 Coal prompt prices obtained from Platts.

PJM. The same is true for the CC configuration. Steam units, like the coal plant, do provide Tier 1 synchronized reserve, but the 2007 Tier 1 revenues were minimal. Real-time ancillary service revenues for the provision of regulation service for both the CT and CC plant are also set to zero since these plant types typically do not provide regulation service in PJM. Additionally, no black start service capability is assumed for the reference CT plant configuration in either costs or revenues. Real-time ancillary service revenues for the provision of regulation were calculated for the CP plant. The regulation offer price was the sum of the calculated hourly cost to supply regulation service plus an adder of $7.50, per PJM market rules. This offer price was compared to the hourly clearing price in the PJM Regulation Market. The clearing price includes both the offer price and the lost opportunity cost of the marginal unit in each hour. If the reference CP could provide regulation at a total cost, including the CP opportunity cost, that is less than the regulation-clearing price, the regulation service net revenue equals the market price of regulation minus the cost of CP regulation.

Generators receive revenues for the provision of reactive services based on cost-of-service filings with the United States Federal Energy Regulatory Commission (FERC). The actual reactive service payments filed with and approved by the FERC for each generator class were used to determine the reactive revenues. Reactive service revenues are based on the weighted-average reactive service rate per MW-year calculated from the data in the FERC filings. In 2007, for CTs, the calculated rate is $2,154 per installed MW-year; for CCs, the calculated rate is $3,094 per installed MW-year and for CPs, the calculated rate is $2,350 per installed MW-year.[28]

Table 3-6 Burner tip average fuel price in PJM (Dollars per MBtu): Calendar years 1999 to 2007

	Natural Gas	Low Sulfur Coal
1999	$2.62	$1.62
2000	$5.18	$1.39
2001	$4.52	$2.14
2002	$3.81	$1.54
2003	$6.45	$1.76
2004	$6.65	$2.74
2005	$9.73	$2.88
2006	$7.40	$2.68
2007	$7.87	$2.53

Zonal Real-Time Energy Market net revenue under a peak-hour, economic dispatch scenario for 1999 to 2007 is shown in Table 3-7, Table 3-8 and Table 3-9 for new entrant CT, CC and CP facilities, respectively. The difference in net revenue among zones is a direct result of the locational variation in hourly LMP. The difference in net revenue among the generation technologies is a direct result of the variation in marginal cost associated with each.

28 The CT plant reactive revenues are based on 27 recent filings with the FERC for CT reactive costs. The CC plant revenues are based on 22 recent filings with the FERC for CC reactive costs, and the CP plant revenues are based on 12 recent filings with the FERC for CP reactive costs. These figures have been updated from those reported in the *2006 State of the Market Report* to include new generation filings.

Table 3-7 PJM Real-Time Energy Market net revenue for a new entrant gas-fired CT under economic dispatch (Dollars per installed MW-year): Net revenue for calendar years 1999 to 2007

Zone	1999	2000	2001	2002	2003	2004	2005	2006	2007	Average
AECO	$56,278	$12,077	$40,825	$19,449	$5,274	$6,765	$18,309	$23,165	$41,985	$24,903
AEP	NA	NA	NA	NA	NA	NA	$641	$4,638	$5,959	$3,746
AP	NA	NA	NA	NA	$1,069	$864	$5,190	$10,695	$17,726	$7,109
BGE	$54,770	$7,193	$23,048	$20,049	$4,196	$2,899	$22,293	$31,725	$56,613	$24,754
ComEd	NA	NA	NA	NA	NA	NA	$1,747	$7,131	$9,271	$6,050
DAY	NA	NA	NA	NA	NA	NA	$793	$4,342	$5,776	$3,637
Dominion	NA	NA	NA	NA	NA	NA	NA	$26,830	$43,653	$35,242
DPL	$57,625	$12,712	$49,833	$22,430	$5,587	$2,881	$14,259	$17,265	$34,151	$24,083
DLCO	NA	NA	NA	NA	NA	NA	$665	$5,408	$9,805	$5,293
JCPL	$55,947	$9,803	$37,473	$13,933	$2,982	$14,472	$16,933	$15,932	$37,836	$22,812
Met-Ed	$54,998	$8,068	$30,697	$17,372	$3,603	$2,271	$15,174	$17,503	$36,393	$20,675
PECO	$56,510	$11,760	$37,989	$14,761	$4,836	$1,600	$16,114	$15,600	$28,560	$20,859
PENELEC	$54,997	$7,360	$18,137	$12,117	$1,731	$1,264	$3,117	$6,585	$10,957	$12,918
Pepco	$54,556	$7,022	$18,108	$22,024	$4,610	$3,915	$25,840	$37,801	$58,816	$25,855
PPL	$55,305	$7,753	$26,748	$12,589	$2,265	$1,120	$12,403	$13,612	$25,472	$17,474
PSEG	$56,271	$10,171	$36,818	$13,499	$4,555	$13,163	$16,881	$15,980	$32,405	$22,194
RECO	NA	NA	NA	NA	$4,213	$3,749	$12,971	$13,606	$32,295	$13,367
PJM	$55,612	$8,498	$30,254	$14,496	$2,763	$919	$6,141	$10,996	$17,933	$16,401

Table 3-8 PJM Real-Time Energy Market net revenue for a new entrant gas-fired CC under economic dispatch (Dollars per installed MW-year): Net revenue for calendar years 1999 to 2007

Zone	1999	2000	2001	2002	2003	2004	2005	2006	2007	Average
AECO	$80,930	$29,354	$68,323	$46,203	$35,658	$52,625	$77,223	$78,489	$107,344	$64,017
AEP	NA	NA	NA	NA	NA	NA	$12,533	$21,695	$29,990	$21,406
AP	NA	NA	NA	NA	$19,036	$20,163	$35,748	$41,735	$65,495	$36,435
BGE	$78,672	$21,290	$42,575	$45,040	$29,165	$33,539	$75,682	$83,645	$131,526	$60,126
ComEd	NA	NA	NA	NA	NA	NA	$21,779	$30,731	$42,289	$31,600
DAY	NA	NA	NA	NA	NA	NA	$11,872	$19,706	$30,024	$20,534
Dominion	NA	NA	NA	NA	NA	NA	NA	$78,267	$110,994	$94,631
DPL	$83,748	$34,057	$79,508	$49,163	$33,913	$39,091	$61,167	$61,072	$99,001	$60,080
DLCO	NA	NA	NA	NA	NA	NA	$10,781	$18,897	$32,552	$20,743
JCPL	$80,716	$25,825	$61,175	$36,979	$26,955	$63,200	$67,269	$56,368	$108,661	$58,572
Met-Ed	$79,528	$22,995	$53,339	$41,469	$27,374	$31,279	$57,351	$59,317	$102,856	$52,834
PECO	$81,255	$28,010	$61,526	$38,389	$31,489	$34,570	$61,212	$57,349	$89,797	$53,733
PENELEC	$79,720	$23,011	$39,473	$42,071	$22,929	$21,460	$26,611	$30,472	$51,289	$37,448
Pepco	$78,343	$20,865	$36,952	$46,354	$29,914	$36,202	$82,427	$91,120	$133,305	$61,720
PPL	$79,926	$22,122	$48,045	$34,624	$25,278	$24,688	$51,686	$52,858	$85,950	$47,242
PSEG	$82,577	$28,650	$62,468	$37,769	$34,549	$63,575	$78,181	$66,446	$105,692	$62,212
RECO	NA	NA	NA	NA	$33,679	$44,473	$64,071	$61,510	$103,158	$61,378
PJM	$80,546	$24,794	$54,206	$38,625	$27,155	$27,389	$35,608	$44,692	$66,616	$44,403

Table 3-9 PJM Real-Time Energy Market net revenue for a new entrant CP under economic dispatch (Dollars per installed MW-year): Net revenue for calendar years 1999 to 2007

Zone	1999	2000	2001	2002	2003	2004	2005	2006	2007	Average
AECO	$92,532	$113,438	$108,787	$105,966	$168,971	$167,610	$301,137	$228,664	$303,350	$176,717
AEP	NA	NA	NA	NA	NA	NA	$142,931	$122,131	$158,510	$141,191
AP	NA	NA	NA	NA	$140,178	$114,188	$225,283	$173,387	$243,442	$179,296
BGE	$90,218	$99,688	$81,733	$103,811	$163,240	$138,798	$297,298	$243,615	$339,865	$173,141
ComEd	NA	NA	NA	NA	NA	NA	$136,055	$117,135	$152,722	$135,304
DAY	NA	NA	NA	NA	NA	NA	$132,250	$114,159	$157,981	$134,797
Dominion	NA	NA	NA	NA	NA	NA	NA	$235,662	$316,223	$275,943
DPL	$96,172	$124,924	$129,746	$109,500	$168,958	$150,777	$280,855	$208,044	$296,729	$173,967
DLCO	NA	NA	NA	NA	NA	NA	$119,344	$102,923	$145,539	$122,602
JCPL	$92,252	$105,657	$99,367	$94,661	$155,564	$177,105	$284,427	$198,595	$310,102	$168,637
Met-Ed	$91,053	$102,018	$92,371	$99,157	$157,131	$135,061	$269,900	$205,508	$299,833	$161,337
PECO	$92,923	$112,043	$101,558	$96,113	$163,941	$144,385	$279,306	$203,152	$284,280	$164,189
PENELEC	$91,889	$109,408	$84,093	$107,445	$154,295	$114,543	$210,236	$156,723	$222,720	$139,039
Pepco	$89,875	$99,351	$75,464	$105,125	$164,995	$142,377	$307,867	$254,964	$344,407	$176,047
PPL	$91,447	$100,853	$86,582	$89,955	$152,675	$127,012	$260,567	$196,349	$279,724	$153,907
PSEG	$95,195	$121,405	$108,158	$96,439	$174,161	$180,518	$309,870	$219,768	$310,978	$179,610
RECO	NA	NA	NA	NA	$176,678	$159,188	$292,449	$213,850	$304,891	$229,411
PJM	$92,935	$108,624	$95,361	$96,828	$159,912	$124,497	$222,911	$177,852	$244,419	$147,038

New Entrant Combustion Turbine

In the peak-hour, economic dispatch analysis, Real-Time Energy Market net revenue was calculated for a CT plant dispatched by PJM operations. For this dispatch scenario, it was assumed that the CT plant could be dispatched by PJM operations in four distinct blocks of four hours of continuous output for each block from the peak-hour period beginning with the hour ending 0800 EPT through to the hour ending 2300 EPT for any block when the real-time, average LMP was greater than, or equal to, the cost to generate, including the cost for a complete startup and shutdown cycle[29] for at least two hours during each four-hour block.[30] The blocks were dispatched independently, and, if there were not at least two economic hours in any given block, then the CT was not dispatched. The startup costs were used in determining the economic hours in each block, but once the CT was dispatched on a particular day, startup costs were not used to evaluate whether to continue to run the unit in the next consecutive four-hour block. The calculations account for operating reserve credits based on PJM rules, as applicable, since the assumed operation is under the direction of PJM operations.

29 Startup and shutdown fuel burns were obtained from design data for a new entry plant. Gas daily cash prices were obtained from Platts fuel prices. Per PJM. "Manual M-15: Cost Development Guidelines," Revision 7 (August 3, 2006), startup and shutdown station power consumption costs were obtained from the station service rates published quarterly by PJM settlements. No-load costs are included in the heat rate.

30 The first block represents the four-hour period starting at hour ending 0800 EPT until hour ending 1100 EPT. The second block represents the four-hour period starting at hour ending 1200 EPT until hour ending 1500 EPT. The third block represents the four-hour period starting at hour ending 1600 EPT until hour ending 1900 EPT, and the fourth block represents the four-hour period starting at hour ending 2000 EPT until the hour ending 2300 EPT.

Net revenues for the new entrant CT under peak-hour, economic dispatch are shown in Table 3-10 for the years 1999 through 2007. This table shows the contribution of each market individually to the new entrant CT's total net revenue. The increase in capacity revenue is a result of the implementation of RPM.

Table 3-10 Real-time PJM-wide net revenue for a CT under peak-hour, economic dispatch by market (Dollars per installed MW-year): Calendar years 1999 to 2007

	Energy	Capacity	Synchronized	Regulation	Reactive	Total
1999	$55,612	$16,677	$0	$0	$2,248	$74,537
2000	$8,498	$20,200	$0	$0	$2,248	$30,946
2001	$30,254	$30,960	$0	$0	$2,248	$63,462
2002	$14,496	$11,516	$0	$0	$2,248	$28,260
2003	$2,763	$5,554	$0	$0	$2,248	$10,566
2004	$919	$5,376	$0	$0	$2,248	$8,543
2005	$6,141	$2,048	$0	$0	$2,248	$10,437
2006	$10,996	$1,758	$0	$0	$2,194	$14,948
2007	$17,933	$28,442	$0	$0	$2,154	$48,530

Table 3-11 shows the total net revenue (the Total column in Table 3-10) for the new entrant CT in each zone. For the nine-year period, the average total net revenue under the peak-hour, economic dispatch scenario was $32,248 per installed MW-year.

Table 3-11 Real-time zonal combined net revenue from all markets for a CT under peak-hour, economic dispatch (Dollars per installed MW-year): Calendar years 1999 to 2007

	1999	2000	2001	2002	2003	2004	2005	2006	2007	Average
AECO	$75,203	$34,525	$74,033	$33,213	$13,077	$14,389	$22,605	$27,117	$81,801	$41,774
AEP	NA	NA	NA	NA	NA	NA	$4,936	$8,590	$16,230	$9,919
AP	NA	NA	NA	NA	$10,800	$8,487	$9,485	$14,647	$27,996	$14,283
BGE	$73,695	$29,641	$56,256	$33,813	$11,998	$10,522	$26,589	$35,678	$94,710	$41,434
ComEd	NA	NA	NA	NA	NA	NA	$7,602	$11,083	$19,542	$12,742
DAY	NA	NA	NA	NA	NA	NA	$5,089	$8,294	$16,047	$9,810
Dominion	NA	NA	NA	NA	NA	NA	NA	$30,782	$53,923	$42,353
DPL	$76,550	$35,160	$83,041	$36,193	$13,389	$10,505	$18,554	$21,217	$73,967	$40,953
DLCO	NA	NA	NA	NA	NA	NA	$4,960	$9,360	$20,076	$11,465
JCPL	$74,871	$32,251	$70,681	$27,697	$10,784	$22,096	$21,229	$19,884	$77,652	$39,683
Met-Ed	$73,923	$30,516	$63,905	$31,136	$11,406	$9,894	$19,469	$21,455	$46,663	$34,263
PECO	$75,434	$34,208	$71,197	$28,525	$12,638	$9,224	$20,409	$19,552	$68,376	$37,729
PENELEC	$73,921	$29,808	$51,345	$25,881	$9,533	$8,887	$7,413	$10,537	$21,228	$26,506
Pepco	$73,480	$29,470	$51,316	$35,788	$12,413	$11,539	$30,135	$41,753	$96,913	$42,534
PPL	$74,229	$30,201	$59,956	$26,353	$10,068	$8,744	$16,699	$17,564	$35,743	$31,062
PSEG	$75,196	$32,618	$70,026	$27,263	$12,357	$20,786	$21,177	$19,933	$72,221	$39,064
RECO	NA	NA	NA	NA	$12,016	$11,373	$17,266	$17,558	$72,112	$26,065
PJM	$74,537	$30,946	$63,462	$28,260	$10,566	$8,543	$10,437	$14,948	$48,530	$32,248

New Entrant Combined Cycle

Under peak-hour, economic dispatch, Energy Market net revenues were calculated for a CC plant dispatched by PJM operations for continuous output from the peak-hour period beginning with the hour ending 0800 EPT and continuing to the hour ending 2300 EPT for any day when the PJM real-time, average LMP was greater than, or equal to, the cost to generate, including the cost for a complete startup and shutdown cycle for at least eight hours during that time period.[31] If there were not eight economic hours in any given day, then the CC was not dispatched. The calculations account for operating reserve payments based on PJM rules, when applicable, since the assumed operation is under the direction of PJM operations. This dispatch scenario uses the same variable operation and maintenance cost, outage, fuel cost, emission and plant performance assumptions reflected in the Table 3-8 results.

Net revenues for the new entrant CC under peak-hour, economic dispatch are shown in Table 3-12 for the years 1999 through 2007. This table shows the contribution of each market individually to the new entrant CC's total net revenue. The increase in capacity revenue is a result of the implementation of RPM.

Table 3-12 Real-time PJM-wide net revenue for a CC under peak-hour, economic dispatch by market (Dollars per installed MW-year): Calendar years 1999 to 2007

	Energy	Capacity	Synchronized	Regulation	Reactive	Total
1999	$80,546	$16,999	$0	$0	$3,155	$100,700
2000	$24,794	$19,643	$0	$0	$3,155	$47,592
2001	$54,206	$29,309	$0	$0	$3,155	$86,670
2002	$38,625	$10,492	$0	$0	$3,155	$52,272
2003	$27,155	$5,281	$0	$0	$3,155	$35,591
2004	$27,389	$5,241	$0	$0	$3,155	$35,785
2005	$35,608	$2,054	$0	$0	$3,155	$40,817
2006	$44,692	$1,743	$0	$0	$3,094	$49,529
2007	$66,616	$31,098	$0	$0	$3,094	$100,809

Table 3-13 shows the total net revenue (the Total column in Table 3-12) for the new entrant CC in each zone. For the nine-year period, the average total net revenue under the peak-hour, economic dispatch scenario was $61,085 per installed MW-year.

31 Startup and shutdown fuel burns obtained from actual PJM installed capacity. Gas daily cash prices obtained from Platts fuel prices. Per PJM. "Manual M-15: Cost Development Guidelines," Revision 7 (August 3, 2007), startup and shutdown station power consumption costs were obtained from the station service rates published quarterly by PJM settlements. No-load costs are included in the heat rate and subsequently the dispatch price since each unit type is dispatched at full load for every economic hour and off for every uneconomic hour; therefore, there is a single offer point and no offer curve.

Table 3-13 Real-time zonal combined net revenue from all markets for a CC under peak-hour, economic dispatch (Dollars per installed MW-year): Calendar years 1999 to 2007

	1999	2000	2001	2002	2003	2004	2005	2006	2007	Average
AECO	$101,084	$52,152	$100,786	$59,850	$44,094	$61,021	$82,432	$83,326	$151,617	$81,818
AEP	NA	NA	NA	NA	NA	NA	$17,742	$26,533	$41,958	$28,744
AP	NA	NA	NA	NA	$29,766	$28,560	$40,957	$46,572	$77,463	$44,664
BGE	$98,827	$44,088	$75,039	$58,688	$37,601	$41,935	$80,891	$88,482	$173,918	$77,719
ComEd	NA	NA	NA	NA	NA	NA	$28,702	$35,568	$54,257	$39,509
DAY	NA	NA	NA	NA	NA	NA	$17,081	$24,543	$41,992	$27,872
Dominion	NA	NA	NA	NA	NA	NA	NA	$83,104	$122,962	$103,033
DPL	$103,903	$56,855	$111,972	$62,811	$42,349	$47,487	$66,376	$65,909	$143,274	$77,882
DLCO	NA	NA	NA	NA	NA	NA	$15,990	$23,734	$44,520	$28,081
JCPL	$100,871	$48,623	$93,639	$50,626	$35,391	$71,596	$72,478	$61,205	$152,934	$76,374
Met-Ed	$99,682	$45,793	$85,803	$55,117	$35,810	$39,675	$62,560	$64,155	$114,824	$67,047
PECO	$101,410	$50,808	$93,990	$52,036	$39,925	$42,967	$66,421	$62,187	$134,069	$71,535
PENELEC	$99,875	$45,809	$71,937	$55,718	$31,365	$29,856	$31,820	$35,309	$63,257	$51,661
Pepco	$98,497	$43,663	$69,416	$60,001	$38,350	$44,598	$87,636	$95,957	$175,698	$79,313
PPL	$100,081	$44,920	$80,509	$48,272	$33,714	$33,084	$56,895	$57,695	$97,918	$61,454
PSEG	$102,731	$51,448	$94,932	$51,416	$42,985	$71,972	$83,390	$71,284	$149,965	$80,014
RECO	NA	NA	NA	NA	$42,115	$52,870	$69,280	$66,348	$147,431	$75,609
PJM	$100,700	$47,592	$86,670	$52,272	$35,591	$35,785	$40,817	$49,529	$100,809	$61,085

New Entrant Coal Plant

The new entrant CP Real-Time Energy Market net revenues were calculated assuming that the plant had a 24-hour minimum run time and was dispatched by PJM operations for all available plant hours, both reasonable assumptions for a large CP. The calculations account for operating reserve payments based on PJM rules, when applicable, since the assumed operation is under the direction of PJM operations.[32]

Net revenues for the new entrant CP under peak-hour, economic dispatch are shown in Table 3-14 for the years 1999 through 2007. This table shows the contribution of each market individually to the new entrant CP's total net revenue. The increase in capacity revenue is a result of the implementation of RPM. Regulation revenue is calculated for any hours in which the new entrant CP's regulation offer is below the regulation-clearing price.

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

Table 3-14 Real-time PJM-wide net revenue for a CP under peak-hour, economic dispatch by market (Dollars per installed MW-year): Calendar years 1999 to 2007

	Energy	Capacity	Synchronized	Regulation	Reactive	Total
1999	$92,935	$17,798	$0	$5,596	$1,692	$118,022
2000	$108,624	$20,755	$0	$3,492	$1,692	$134,564
2001	$95,361	$30,862	$0	$1,356	$1,692	$129,271
2002	$96,828	$11,493	$0	$2,118	$1,692	$112,131
2003	$159,912	$5,688	$0	$2,218	$1,692	$169,509
2004	$124,497	$5,537	$0	$1,399	$1,692	$133,124
2005	$222,911	$2,100	$0	$1,727	$1,692	$228,430
2006	$177,852	$1,810	$0	$1,107	$1,692	$182,461
2007	$244,419	$29,343	$0	$1,172	$2,350	$277,284

Table 3-15 shows the total net revenue (the Total column 7 in Table 3-14) for the new entrant CP in each zone. For the nine-year period, the average total net revenue under the economic dispatch scenario was $164,977 per installed MW-year.

Table 3-15 Real-time zonal combined net revenue from all markets for a CP under peak-hour, economic dispatch (Dollars per installed MW-year): Calendar years 1999 to 2007

	1999	2000	2001	2002	2003	2004	2005	2006	2007	Average
AECO	$118,254	$137,752	$143,257	$121,784	$179,116	$176,826	$306,995	$233,787	$345,738	$195,945
AEP	NA	NA	NA	NA	NA	NA	$150,175	$127,587	$170,532	$149,431
AP	NA	NA	NA	NA	$152,457	$123,619	$231,962	$178,701	$255,474	$188,443
BGE	$115,925	$124,106	$116,306	$119,714	$173,476	$148,096	$303,218	$248,763	$380,425	$192,225
ComEd	NA	NA	NA	NA	NA	NA	$144,924	$122,647	$164,740	$144,104
DAY	NA	NA	NA	NA	NA	NA	$139,572	$119,691	$169,420	$142,894
Dominion	NA	NA	NA	NA	NA	NA	NA	$240,827	$328,069	$284,448
DPL	$121,871	$149,239	$164,219	$125,338	$179,144	$160,036	$287,242	$213,261	$339,158	$193,279
DLCO	NA	NA	NA	NA	NA	NA	$126,378	$108,417	$157,544	$130,780
JCPL	$117,957	$129,968	$133,853	$110,646	$165,730	$186,316	$290,747	$203,776	$352,520	$187,946
Met-Ed	$116,776	$126,375	$126,885	$115,061	$167,367	$144,385	$276,295	$210,719	$311,759	$177,291
PECO	$118,636	$136,379	$136,046	$112,096	$174,147	$153,658	$285,681	$208,381	$326,717	$183,527
PENELEC	$117,603	$133,724	$118,787	$123,416	$164,692	$123,984	$217,133	$162,124	$234,789	$155,139
Pepco	$115,585	$123,766	$110,089	$121,020	$175,224	$151,666	$314,137	$260,110	$384,940	$195,171
PPL	$117,165	$125,227	$121,146	$105,991	$162,900	$136,364	$267,023	$201,584	$291,701	$169,900
PSEG	$120,910	$145,675	$142,694	$112,409	$184,332	$189,716	$316,131	$224,904	$353,386	$198,906
RECO	NA	NA	NA	NA	$186,859	$168,414	$298,795	$219,016	$347,309	$244,079
PJM	$118,022	$134,564	$129,271	$112,131	$169,509	$133,124	$228,430	$182,461	$277,284	$164,977

New Entrant Day-Ahead Net Revenues

In order to develop a comprehensive net revenue analysis, Day-Ahead Energy Market net revenues were calculated for the CT, CC and CP technologies for the peak-hour, economic dispatch scenario used for the Real-Time Energy Market analysis.[33, 34] The results for the Day-Ahead Energy Market for each class are presented in Table 3-16, Table 3-17 and Table 3-18, respectively.

Table 3-16 PJM Day-Ahead Energy Market net revenue for a new entrant gas-fired CT under economic dispatch (Dollars per installed MW-year): Calendar years 2000 to 2007

	2000	2001	2002	2003	2004	2005	2006	2007	Average
AECO	$12,077	$29,022	$18,894	$2,634	$1,360	$11,975	$13,446	$20,649	$13,757
AEP	NA	NA	NA	NA	NA	$563	$1,218	$2,267	$1,349
AP	NA	NA	NA	$595	$0	$3,959	$7,326	$7,244	$3,825
BGE	$7,193	$14,772	$14,087	$1,779	$42	$9,857	$13,886	$20,904	$10,315
ComEd	NA	NA	NA	NA	NA	$374	$1,709	$4,392	$2,158
DAY	NA	NA	NA	NA	NA	$477	$1,104	$2,003	$1,195
Dominion	NA	NA	NA	NA	NA	NA	$10,991	$15,078	$13,035
DPL	$12,712	$35,962	$21,844	$2,419	$95	$7,869	$9,733	$12,438	$12,884
DLCO	NA	NA	NA	NA	NA	$308	$854	$1,818	$993
JCPL	$9,803	$24,565	$16,658	$1,531	$489	$7,104	$8,263	$16,080	$10,562
Met-Ed	$8,068	$19,353	$17,218	$1,273	$50	$8,737	$12,771	$14,559	$10,254
PECO	$11,760	$26,271	$17,522	$2,089	$0	$10,129	$8,598	$11,330	$10,962
PENELEC	$7,360	$16,870	$15,415	$537	$0	$1,477	$3,461	$3,736	$6,107
Pepco	$7,022	$14,469	$13,780	$2,143	$0	$12,988	$18,258	$23,028	$11,461
PPL	$7,753	$18,174	$15,151	$993	$0	$7,052	$8,259	$9,586	$8,371
PSEG	$10,171	$25,298	$16,750	$258	$7,332	$7,332	$8,127	$12,718	$10,998
RECO	NA	NA	NA	$1,346	$11	$5,925	$7,143	$11,711	$5,227
PJM	$7,418	$20,390	$13,921	$1,282	$1	$2,996	$5,229	$6,751	$7,249

33 The Day-Ahead Energy Market net revenues were calculated utilizing the same fuel, weather and unit operational assumptions as were used for the Real-Time Energy Market net revenue calculations.

34 The Day-Ahead Energy Market went into operation on June 1, 2000. For the analysis presented in Table 3-16, Table 3-17 and Table 3-18, the Real-Time Energy Market LMP was used from January 1, 2000, to May 31, 2000.

Table 3-17 PJM Day-Ahead Energy Market net revenue for a new entrant gas-fired CC under economic dispatch (Dollars per installed MW-year): Calendar years 2000 to 2007

	2000	2001	2002	2003	2004	2005	2006	2007	Average
AECO	$29,354	$63,679	$45,357	$31,788	$43,308	$74,855	$62,589	$83,745	$54,334
AEP	NA	NA	NA	NA	NA	$10,462	$12,393	$19,516	$14,124
AP	NA	NA	NA	$14,992	$14,077	$29,993	$30,144	$44,880	$26,817
BGE	$21,290	$37,791	$34,829	$23,003	$23,810	$60,143	$64,078	$94,045	$44,874
ComEd	NA	NA	NA	NA	NA	$9,888	$12,746	$35,333	$19,322
DAY	NA	NA	NA	NA	NA	$8,451	$9,671	$19,014	$12,379
Dominion	NA	NA	NA	NA	NA	NA	$57,718	$80,321	$69,020
DPL	$34,057	$73,455	$48,709	$28,595	$28,534	$59,804	$49,939	$74,526	$49,702
DLCO	NA	NA	NA	NA	NA	$7,709	$8,390	$17,819	$11,306
JCPL	$25,825	$51,367	$39,102	$23,929	$48,514	$56,951	$42,774	$85,349	$46,726
Met-Ed	$22,995	$44,572	$38,810	$22,806	$22,786	$52,522	$50,581	$75,423	$41,312
PECO	$28,010	$55,775	$40,411	$27,252	$26,450	$59,822	$47,607	$70,234	$44,445
PENELEC	$23,011	$43,234	$47,776	$17,460	$13,209	$23,711	$22,590	$35,002	$28,249
Pepco	$20,865	$37,135	$34,523	$24,379	$26,052	$67,659	$71,755	$99,380	$47,719
PPL	$22,122	$42,383	$35,750	$19,862	$17,037	$48,895	$43,246	$64,603	$36,737
PSEG	$28,650	$57,168	$41,945	$27,192	$47,450	$65,167	$51,543	$87,724	$50,855
RECO	NA	NA	NA	$25,148	$31,204	$54,167	$50,064	$85,050	$49,127
PJM	$26,132	$48,253	$35,993	$21,865	$18,193	$28,413	$31,670	$44,434	$31,869

Table 3-18 PJM Day-Ahead Energy Market net revenue for a new entrant CP under economic dispatch (Dollars per installed MW-year): Calendar years 2000 to 2007

	2000	2001	2002	2003	2004	2005	2006	2007	Average
AECO	$113,438	$111,272	$108,715	$174,964	$156,185	$302,113	$215,274	$252,783	$179,343
AEP	NA	NA	NA	NA	NA	$140,898	$111,399	$150,551	$134,283
AP	NA	NA	NA	$145,314	$108,867	$219,168	$158,105	$223,836	$171,058
BGE	$99,688	$83,030	$94,034	$161,419	$127,630	$284,669	$223,199	$304,373	$172,255
ComEd	NA	NA	NA	NA	NA	$133,407	$108,663	$149,353	$130,474
DAY	NA	NA	NA	NA	NA	$126,886	$98,084	$148,879	$124,616
Dominion	NA	NA	NA	NA	NA	NA	$215,727	$289,976	$252,852
DPL	$124,924	$128,020	$111,746	$172,871	$141,541	$286,686	$201,807	$278,619	$180,777
DLCO	NA	NA	NA	NA	NA	$121,687	$92,737	$137,774	$117,399
JCPL	$105,657	$94,134	$99,105	$164,028	$161,584	$278,746	$188,852	$289,222	$172,666
Met-Ed	$102,018	$88,922	$99,331	$161,077	$127,001	$269,696	$199,865	$275,949	$165,482
PECO	$112,043	$102,119	$101,674	$169,018	$137,889	$284,530	$198,441	$272,984	$172,337
PENELEC	$109,408	$89,643	$118,915	$157,282	$108,203	$207,894	$147,998	$208,246	$143,449
Pepco	$99,351	$82,420	$93,756	$163,851	$130,908	$295,462	$233,288	$313,215	$176,531
PPL	$100,853	$86,022	$93,528	$156,929	$120,447	$263,597	$190,672	$263,141	$159,399
PSEG	$121,405	$108,221	$106,049	$173,952	$162,402	$295,693	$207,951	$294,953	$183,828
RECO	NA	NA	NA	$172,622	$143,445	$279,769	$207,438	$291,031	$218,861
PJM	$116,784	$95,119	$97,493	$162,285	$113,892	$220,824	$167,282	$221,757	$149,430

For the eight-year period, the average PJM Day-Ahead Energy Market net revenue under the peak-hour, economic dispatch scenario for the CT plant was $7,249 per installed MW-year. For the CC plant, the eight-year average Day-Ahead Energy Market net revenue under the peak-hour, economic dispatch scenario was $31,869 per installed MW-year. For the CP plant, the eight-year average Day-Ahead Energy Market net revenue under the peak-hour, economic dispatch scenario was $149,430 per installed MW-year.

The energy net revenues for both the Real-Time and Day-Ahead Energy Markets are shown in Table 3-19, Table 3-20 and Table 3-21 for the CT, CC and CP plants, respectively.

On average, the Real-Time Energy Market net revenue was 37 percent higher than the Day-Ahead Market net revenue for the CT plant, 20 percent higher for the CC plant and 3 percent higher for the CP.[35]

Table 3-19 Real-Time and Day-Ahead Energy Market net revenues for a CT under economic dispatch (Dollars per installed MW-year): Calendar years 2000 to 2007

	Real-Time Economic	Day-Ahead Economic	Actual Difference	Percent Difference
2000	$8,498	$7,418	$1,080	13%
2001	$30,254	$20,390	$9,864	33%
2002	$14,496	$13,921	$575	4%
2003	$2,763	$1,282	$1,481	54%
2004	$919	$1	$918	100%
2005	$6,141	$2,996	$3,145	51%
2006	$10,996	$5,229	$5,767	52%
2007	$17,933	$6,751	$11,182	62%
Average	$11,500	$7,249	$4,252	37%

Table 3-20 Real-Time and Day-Ahead Energy Market net revenues for a CC under economic dispatch scenario (Dollars per installed MW-year): Calendar years 2000 to 2007

	Real-Time Economic	Day-Ahead Economic	Actual Difference	Percent Difference
2000	$24,794	$26,132	($1,338)	(5%)
2001	$54,206	$48,253	$5,953	11%
2002	$38,625	$35,993	$2,632	7%
2003	$27,155	$21,865	$5,290	19%
2004	$27,389	$18,193	$9,196	34%
2005	$35,608	$28,413	$7,195	20%
2006	$44,692	$31,670	$13,022	29%
2007	$66,616	$44,434	$22,182	33%
Average	$39,886	$31,869	$8,017	20%

35 The Day-Ahead Energy Market was initialized on June 1, 2000. For the analysis presented in Table 3-19, Table 3-20 and Table 3-21, the Real-Time Energy Market LMP was used from January 1, 2000, to May 31, 2000.

Table 3-21 Real-Time and Day-Ahead Energy Market net revenues for a CP under economic dispatch scenario (Dollars per installed MW-year): Calendar years 2000 to 2007

	Real-Time Economic	Day-Ahead Economic	Actual Difference	Percent Difference
2000	$108,624	$116,784	($8,160)	(8%)
2001	$95,361	$95,119	$242	0%
2002	$96,828	$97,493	($665)	(1%)
2003	$159,912	$162,285	($2,373)	(1%)
2004	$124,497	$113,892	$10,605	9%
2005	$222,911	$220,824	$2,087	1%
2006	$177,852	$167,282	$10,570	6%
2007	$244,419	$221,757	$22,662	9%
Average	$153,801	$149,430	$4,371	3%

Net Revenue Adequacy

To put the 2007 net revenue results in perspective, net revenues are compared to the annual, levelized fixed costs for each technology. The MMU reevaluated the fixed costs for all three new entry plant configurations for 2007. The estimated, 20-year levelized fixed costs[36] are $90,656 per installed MW-year for the new entrant CT plant,[37] $143,600 per installed MW-year for the new entrant CC plant and $359,750 per installed MW-year for the new entrant CP plant.[38] Levelized fixed costs increased significantly for all three technologies. Table 3-22 shows the 20-year levelized costs for each technology for the period 2005 through 2007.[39] The increased costs of constructing generation facilities are the result of a combination of factors, including increased worldwide demand. For example, increased demand has caused significant increases in the cost of input materials as well as the actual cost of construction for gas-fired turbines, affecting fixed costs of both new entrant CTs and CCs.[40]

In this section, net revenue includes net revenue from the Real-Time Energy Market, from the Capacity Market and from any applicable ancillary service.

Table 3-22 New entrant 20-year levelized fixed costs (By plant type (Dollars per installed MW-year))

	2005	2006	2007
	20-Year Levelized Fixed Cost	20-Year Levelized Fixed Cost	20-Year Levelized Fixed Cost
CT	$72,207	$80,315	$90,656
CC	$93,549	$99,230	$143,600
CP	$208,247	$267,792	$359,750

36 Annual fixed costs may vary by location. The fixed costs used here are based on a location in the PJM Mid-Atlantic Region.

37 This analysis was performed for the MMU by Pasteris Energy, Inc. The annual costs were based on a 20-year project life, 50/50 debt-to-equity financing with a target internal rate of return (IRR) of 12 percent and a debt rate of 7 percent. For depreciation, the analysis assumed a 15-year modified accelerated cost-recovery schedule (MACRS) for the CT plant and 20-year MACRS for the CC and CP plants. A general annual rate of cost inflation of 2.5 percent was utilized in all calculations.

38 Installed capacity at an average Philadelphia ambient air temperature of 54 degrees F. during the study period of 1999 to 2007.

39 The figures in Table 3-22 represent the annual cost per MW per year if total costs were levelized over the 20-year life cycle of the plant. These fixed costs of construction are specific to the PJM Mid-Atlantic Region.

40 "Section 2, Budget Plant Prices," "Price Trends," *2007-08 Gas Turbine World Handbook* (Fairfield, Conn: Pequot Publishing, Inc.) Volume 26, p. 29.

In 2007, under the economic dispatch scenario, average net revenue from the PJM Real-Time Energy Market, the Capacity Market and the Ancillary Service Markets for a new entrant CT were $48,530 per installed MW-year. The associated operating costs were between $80 and $90 per MWh, based on a design heat rate of 10,500 Btu per kWh, average daily delivered natural gas prices of $7.87 per MBtu and a VOM rate of $6.47 per MWh.[41] The average PJM net revenue in 2007 would not have covered the fixed costs of a new CT. As shown in Table 3-23, the only year when average PJM net revenue was sufficient to cover fixed costs for a new CT was 1999.

Table 3-23 CT 20-year levelized fixed cost vs. real-time economic dispatch net revenue (Dollars per installed MW-year): Calendar years 1999 to 2007

	20-Year Levelized Fixed Cost	Economic Dispatch Net Revenue	Economic Dispatch Percent
1999	$72,207	$74,537	103%
2000	$72,207	$30,946	43%
2001	$72,207	$63,462	88%
2002	$72,207	$28,260	39%
2003	$72,207	$10,566	15%
2004	$72,207	$8,543	12%
2005	$72,207	$10,437	14%
2006	$80,315	$14,948	19%
2007	$90,656	$48,530	54%
Average	$75,158	$32,248	43%

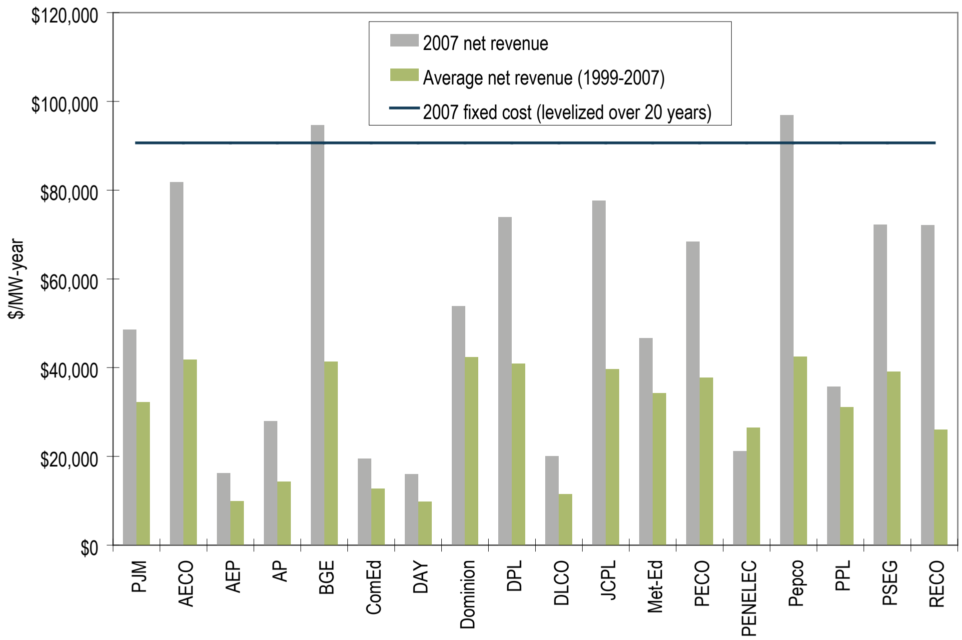
The 20-year levelized fixed cost for 2007 is compared to the economic dispatch net revenue for each zone for the period 1999 to 2007 in Table 3-24. While the average PJM net revenue is not enough to cover the 20-year levelized fixed costs, the net revenues in the Pepco Control Zone and in the BGE Control Zone are more than sufficient to cover the 2007 levelized fixed costs in 2007. Figure 3-3 summarizes the information in Table 3-24, showing the 2007 average net revenue for a new entrant CT, the zonal net revenue for the period 1999 to 2007 and the levelized 2007 fixed cost for a new entrant CT. For every zone except PENELEC, 2007 net revenues for a CT are greater than the nine-year average as the result of increased capacity payments and higher zonal LMPs.

41 The analysis used the daily gas costs and associated production costs for CTs and CCs.

Table 3-24 CT 20-year levelized fixed cost vs. real-time economic dispatch, zonal net revenue (Dollars per installed MW-year): Calendar years 1999 to 2007

	2007			9-Year Average (1999-2007)		
	Net Revenue	20-Year Levelized Cost	Percent Recovered	Net Revenue	20-Year Levelized Cost	Percent Recovered
AECO	$81,801	$90,656	90%	$41,774	$75,158	56%
AEP	$16,230	$90,656	18%	$9,919	$75,158	13%
AP	$27,996	$90,656	31%	$14,283	$75,158	19%
BGE	$94,710	$90,656	104%	$41,434	$75,158	55%
ComEd	$19,542	$90,656	22%	$12,742	$75,158	17%
DAY	$16,047	$90,656	18%	$9,810	$75,158	13%
Dominion	$53,923	$90,656	59%	$42,353	$75,158	56%
DPL	$73,967	$90,656	82%	$40,953	$75,158	54%
DLCO	$20,076	$90,656	22%	$11,465	$75,158	15%
JCPL	$77,652	$90,656	86%	$39,683	$75,158	53%
Met-Ed	$46,663	$90,656	51%	$34,263	$75,158	46%
PECO	$68,376	$90,656	75%	$37,729	$75,158	50%
PENELEC	$21,228	$90,656	23%	$26,506	$75,158	35%
Pepco	$96,913	$90,656	107%	$42,534	$75,158	57%
PPL	$35,743	$90,656	39%	$31,062	$75,158	41%
PSEG	$72,221	$90,656	80%	$39,064	$75,158	52%
RECO	$72,112	$90,656	80%	$26,065	$75,158	35%
PJM	$48,530	$90,656	54%	$32,248	$75,158	43%

Figure 3-3 New entrant CT real-time 2007 net revenue, nine-year average net revenue and 20-year levelized fixed cost as of 2007 (Dollars per installed MW-year): Calendar years 1999 to 2007



In 2007, under the economic dispatch scenario, average net revenue from the PJM Real-Time Energy Market, the Capacity Market and the Ancillary Service Markets for a new entrant CC were $100,809 per installed MW-year. The associated operating costs were between $50 and $60 per MWh, based on a design heat rate of 7,150 Btu per kWh, average daily delivered natural gas prices of $7.87 per MBtu and a VOM rate of $2.00 per MWh. The resulting PJM average net revenue is less than the 20-year levelized fixed cost. Table 3-25 shows the PJM average CC net revenue and associated levelized fixed costs for the period 1999 to 2007. The only year when average PJM net revenue was sufficient to cover the associated 20-year levelized fixed costs for a new entrant CC was 1999. Average 2007 net revenue for a CC is the highest since the opening of PJM markets.

Table 3-25 CC 20-year levelized fixed cost vs. real-time economic dispatch net revenue (Dollars per installed MW-year): Calendar years 1999 to 2007

	20-Year Levelized Fixed Cost	Economic Dispatch Net Revenue	Economic Dispatch Percent
1999	$93,549	$100,700	108%
2000	$93,549	$47,592	51%
2001	$93,549	$86,670	93%
2002	$93,549	$52,272	56%
2003	$93,549	$35,591	38%
2004	$93,549	$35,785	38%
2005	$93,549	$40,817	44%
2006	$99,230	$49,529	50%
2007	$143,600	$100,809	70%
Average	$99,741	$61,085	61%

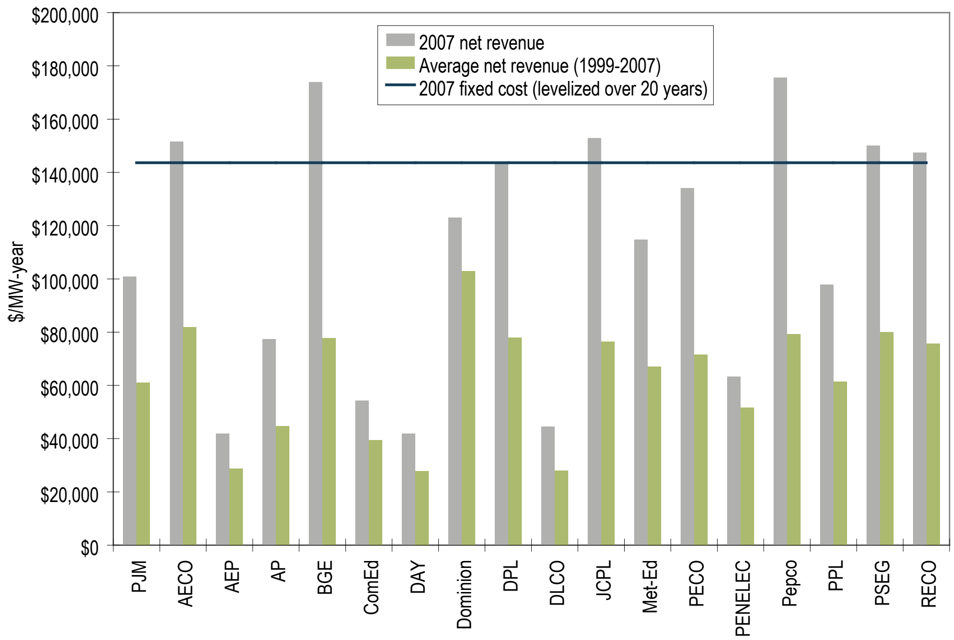
Economic net revenue for the new entrant CC is shown for each zone for the period 1999 to 2007 in Table 3-26, as is the 20-year levelized fixed cost for 2007. While the average PJM net revenue is not enough to cover the levelized fixed costs, the net revenue for the AECO, BGE, JCPL, Pepco, PSEG and RECO control zones is more than sufficient in 2007 to cover the 20-year levelized fixed costs and the net revenue in the DPL Control Zone is approximately equal to the 20-year levelized fixed costs. Figure 3-4 summarizes the information in Table 3-26, showing the 2007 net revenue for a new entrant CC, the average net revenue for the period 1999 to 2007 by zone and the levelized 2007 capital cost for a new entrant CC.[42] For every zone, 2007 net revenues for a CC are greater than the nine-year average as the result of increased capacity payments and higher zonal LMPs.

42 The fixed costs associated with the EMAAC LDA are meant to serve as a baseline for comparison.

Table 3-26 CC 20-year levelized fixed cost vs. real-time economic dispatch, zonal net revenue (Dollars per installed MW-year): Calendar years 1999 to 2007

	2007			9-Year Average (1999-2007)		
	Net Revenue	20-Year Levelized Cost	Percent Recovered	Net Revenue	20-Year Levelized Cost	Percent Recovered
AECO	$151,617	$143,600	106%	$81,818	$99,741	82%
AEP	$41,958	$143,600	29%	$28,744	$99,741	29%
AP	$77,463	$143,600	54%	$44,664	$99,741	45%
BGE	$173,918	$143,600	121%	$77,719	$99,741	78%
ComEd	$54,257	$143,600	38%	$39,509	$99,741	40%
DAY	$41,992	$143,600	29%	$27,872	$99,741	28%
Dominion	$122,962	$143,600	86%	$103,033	$99,741	103%
DPL	$143,274	$143,600	100%	$77,882	$99,741	78%
DLCO	$44,520	$143,600	31%	$28,081	$99,741	28%
JCPL	$152,934	$143,600	107%	$76,374	$99,741	77%
Met-Ed	$114,824	$143,600	80%	$67,047	$99,741	67%
PECO	$134,069	$143,600	93%	$71,535	$99,741	72%
PENELEC	$63,257	$143,600	44%	$51,661	$99,741	52%
Pepco	$175,698	$143,600	122%	$79,313	$99,741	80%
PPL	$97,918	$143,600	68%	$61,454	$99,741	62%
PSEG	$149,965	$143,600	104%	$80,014	$99,741	80%
RECO	$147,431	$143,600	103%	$75,609	$99,741	76%
PJM	$100,809	$143,600	70%	$61,085	$99,741	61%

Figure 3-4 New entrant CC real-time 2007 net revenue, nine-year average net revenue and 20-year levelized fixed cost as of 2007 (Dollars per installed MW-year): Calendar years 1999 to 2007



In 2007, under the economic dispatch scenario, average PJM net revenue from the Real-Time Energy Market, the Capacity Market and the Ancillary Service Markets for a new entrant CP was $277,284 per installed MW-year. The associated operating costs were between $20 and $30 per MWh, based on a design heat rate of 9,500 Btu per kWh, average delivered coal prices of $2.53 per MBtu and a VOM rate of $2.67 per MWh.[43] Table 3-27 shows the PJM average CP net revenue and associated levelized fixed costs for the period 1999 to 2007. For the period, the resulting PJM average net revenue is less than the 20-year levelized fixed cost. The only year when average PJM net revenue was sufficient to cover the levelized fixed costs for a new entrant CP was 2005. Average 2007 net revenue for a CP is the highest since the opening of PJM markets.

43 The analysis used the prompt coal costs and associated production costs for CPs.

Table 3-27 CP 20-year levelized fixed cost vs. real-time economic dispatch net revenue (Dollars per installed MW-year): Calendar years 1999 to 2007

	20-Year Levelized Fixed Cost	Economic Dispatch Net Revenue	Economic Dispatch Percent
1999	$208,247	$118,022	57%
2000	$208,247	$134,564	65%
2001	$208,247	$129,271	62%
2002	$208,247	$112,131	54%
2003	$208,247	$169,509	81%
2004	$208,247	$133,124	64%
2005	$208,247	$228,430	110%
2006	$267,792	$182,461	68%
2007	$359,750	$277,284	77%
Average	$231,697	$164,977	71%

The 2007 20-year levelized fixed cost is compared to economic dispatch, zonal net revenue from all markets for the new entrant CP for the period 1999 to 2007 in Table 3-28. While the average PJM net revenue is not enough to cover the 20-year levelized fixed costs, the net revenue for the BGE and the Pepco control zones is more than sufficient in 2007 to cover the 20-year levelized fixed costs and the net revenues in the AECO, JCPL, PSEG and RECO control zones are within 5 percent of the levelized fixed costs. Figure 3-5 summarizes the information in Table 3-28, showing the 2007 net revenue for a new entrant CP, the average net revenue for the period 1999 to 2007 by zone and the levelized 2007 capital cost for a new entrant CP.[44] For every zone, 2007 net revenues for a CP are greater than the nine-year average as the result of increased capacity payments and higher zonal LMPs.[45]

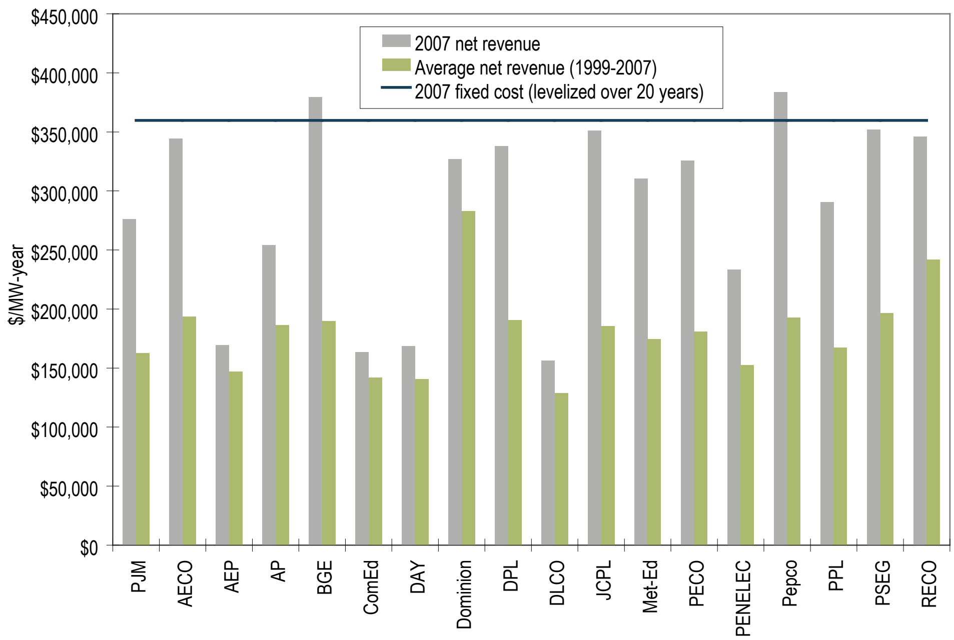
44 The fixed costs associated with the EMAAC LDA are meant to serve as a baseline for comparison.

45 Average net revenues were taken for all years a zone was fully integrated into PJM.

Table 3-28 CP 20-year levelized fixed cost vs. real-time economic dispatch, zonal net revenue (Dollars per installed MW-year): Calendar years 1999 to 2007

	2007			9-Year Average (1999-2007)		
	Net Revenue	20-Year Levelized Cost	Percent Recovered	Net Revenue	20-Year Levelized Cost	Percent Recovered
AECO	$345,738	$359,750	96%	$195,945	$231,697	85%
AEP	$170,532	$359,750	47%	$149,431	$231,697	64%
AP	$255,474	$359,750	71%	$188,443	$231,697	81%
BGE	$380,425	$359,750	106%	$192,225	$231,697	83%
ComEd	$164,740	$359,750	46%	$144,104	$231,697	62%
DAY	$169,420	$359,750	47%	$142,894	$231,697	62%
Dominion	$328,069	$359,750	91%	$284,448	$231,697	123%
DPL	$339,158	$359,750	94%	$193,279	$231,697	83%
DLCO	$157,544	$359,750	44%	$130,780	$231,697	56%
JCPL	$352,520	$359,750	98%	$187,946	$231,697	81%
Met-Ed	$311,759	$359,750	87%	$177,291	$231,697	77%
PECO	$326,717	$359,750	91%	$183,527	$231,697	79%
PENELEC	$234,789	$359,750	65%	$155,139	$231,697	67%
Pepco	$384,940	$359,750	107%	$195,171	$231,697	84%
PPL	$291,701	$359,750	81%	$169,900	$231,697	73%
PSEG	$353,386	$359,750	98%	$198,906	$231,697	86%
RECO	$347,309	$359,750	97%	$244,079	$231,697	105%
PJM	$277,284	$359,750	77%	$164,977	$231,697	71%

Figure 3-5 New entrant CP real-time 2007 net revenue, nine-year average net revenue and 20-year levelized fixed cost as of 2007 (Dollars per installed MW-year): Calendar years 1999 to 2007



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 2007 net revenue indicates that the degree to which fixed costs of new peaking, midmerit and coal-fired baseload plants are covered depends on the location of the new plant. Net revenue in 2007 was significantly above average as the result both of higher Energy Market net revenue and increased Capacity Market net revenue resulting from the RPM. Net revenue was higher than the fixed costs of generation in a number of zones as a result of locational pricing in both the Energy and Capacity Markets.

The returns earned by investors in generating units are a direct function of net revenues. Positive returns may be earned at less than the annualized fixed costs, although the returns are less than the target. A sensitivity analysis was performed to determine the impact of changes in net revenue on the return on investment for a new generating unit. The internal rate of return (IRR) was calculated for a range of 20-year levelized net revenue streams, using 20-year levelized fixed costs from Table 3-22 . Levelized net revenues were modified and the IRR calculated. A $5,000 per MW-year sensitivity was used for the CT; a $10,000 per MW-year sensitivity was used for the CC; and a $20,000 per MW-year sensitivity was used for the CP generator. The results are shown in Table 3-29.[46]

46 This analysis was performed for the MMU by Pasteris Energy, Inc. The annual costs were based on a 20-year project life, 50/50 debt-to-equity financing with a target IRR of 12 percent and a debt rate of 7 percent. For depreciation, the analysis assumed a 15-year modified accelerated cost-recovery schedule (MACRS) for the CT plant and 20-year MACRS for the CC and CP plants. A general annual rate of cost inflation of 2.5 percent was utilized in all calculations.

Table 3-29 Internal rate of return sensitivity for CT, CC and CP generators

	CT		CC		CP	
	20-Year Levelized Net Revenue	20-Year After Tax IRR	20-Year Levelized Net Revenue	20-Year After Tax IRR	20-Year Levelized Net Revenue	20-Year After Tax IRR
Sensitivity 1	$95,656	13.5%	$153,600	13.8%	$379,750	13.7%
Base Case	$90,656	12.0%	$143,600	12.0%	$359,750	12.0%
Sensitivity 2	$85,656	10.5%	$133,600	10.1%	$339,750	10.3%
Sensitivity 3	$80,656	8.8%	$123,600	8.1%	$319,750	8.5%
Sensitivity 4	$75,656	7.1%	$113,600	6.0%	$299,750	6.6%
Sensitivity 5	$70,656	5.2%	$103,600	3.7%	$279,750	4.5%
Sensitivity 6	$65,656	3.1%	$93,600	1.1%	$259,750	2.2%

Existing and Planned Generation

Installed Capacity and Fuel Mix

During calendar year 2007, PJM installed capacity rose slightly from 162,841 MW on January 1 to 163,498 MW on December 31, and the fuel mix also shifted slightly. Installed capacity includes net capacity imports and exports and can vary on a daily basis.

Installed Capacity

On January 1, 2007, PJM installed capacity was 162,840.7 MW.[47] (See Table 3-30.) Over the next five months, unit retirements, facility reratings plus import and export shifts changed installed capacity to 162,036.6 MW on May 31, 2007.[48]

47 Percents shown in Table 3-30 and Table 3-31 are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

48 The capacity delineated herein is the capability of all PJM capacity resources used to serve load irrespective of their disposition in the RPM.

Table 3-30 PJM installed capacity (By fuel source): January 1, May 31, June 1, and December 31, 2007

	1-Jan-07		31-May-07		1-Jun-07		31-Dec-07	
	MW	Percent	MW	Percent	MW	Percent	MW	Percent
Coal	66,613.5	40.9%	66,418.9	41.0%	66,546.0	40.7%	66,286.0	40.5%
Oil	10,771.1	6.6%	10,657.5	6.6%	10,645.0	6.5%	10,640.0	6.5%
Gas	47,528.0	29.2%	46,955.9	29.0%	47,557.0	29.1%	47,599.4	29.1%
Nuclear	30,056.8	18.5%	30,056.8	18.5%	30,880.8	18.9%	30,883.8	18.9%
Solid waste	719.6	0.4%	719.6	0.4%	714.6	0.4%	712.6	0.4%
Hydroelectric	7,122.9	4.4%	7,193.9	4.4%	7,287.2	4.5%	7,311.2	4.5%
Wind	28.8	0.0%	34.0	0.0%	28.8	0.0%	65.4	0.0%
Total	162,840.7	100.0%	162,036.6	100.0%	163,659.4	100.0%	163,498.4	100.0%

At the beginning of the new planning year on June 1, 2007, installed capacity increased by 1,622.8 MW to 163,659.4 MW, a 1.0 percent increase in total PJM capacity over the May 31 level.

On December 31, 2007, PJM installed capacity was 163,498.4 MW.[49]

Energy Production by Fuel Source

In calendar year 2007, coal and nuclear units provided 89.2 percent, natural gas 7.7 percent, oil 0.5 percent, hydroelectric 1.7 percent, solid waste 0.7 percent and wind 0.2 percent of total generation. (See Table 3-31.)

Table 3-31 PJM generation (By fuel source (GWh)): Calendar year 2007

	GWh	Percent
Coal	416,180.7	55.3%
Oil	3,728.1	0.5%
Gas	57,825.8	7.7%
Nuclear	255,040.1	33.9%
Solid waste	4,896.0	0.7%
Hydroelectric	13,080.6	1.7%
Wind	1,345.8	0.2%
Total	752,097.2	100.0%

49 Wind-based resources accounted for 65.4 MW of installed capacity in PJM on December 31, 2007. This value represents approximately 20 percent of wind nameplate capability in PJM. PJM administratively reduces the capabilities of all wind generators to 20 percent of nameplate capacity when determining the system installed capacity because wind resources cannot be assumed to be available on peak and cannot respond to dispatch requests. As data become available, unforced capability of wind resources will be calculated using actual data in place of the 80 percent reduction. There are additional wind resources not reflected in this total because they are energy only resources and do not participate in the PJM Capacity Market.

Planned Generation Additions

Net revenues provide incentives to build new generation to serve PJM markets. While these incentives operate with a significant lag time and are based on expectations of future net revenue, the amount of planned new generation in PJM reflects the market's perception of the incentives provided by the combination of revenues from the PJM Energy, Capacity and Ancillary Service Markets. At the end of 2007, 74,006 MW of capacity were in generation request queues for construction through 2016, compared to an average installed capacity of approximately 163,000 MW in 2007 and a year-end, installed capacity of 163,498 MW. Although it is clear that not all generation in the queues will be built, PJM has added capacity annually since 2000. (See Table 3-32.)

Table 3-32 Year-to-year capacity additions: Calendar years 2000 to 2007[50]

	MW
2000	505
2001	872
2002	3,841
2003	3,524
2004	1,935
2005	819
2006	471
2007	1,265

A more detailed examination of the queue data reveals some additional conclusions. The geographic distribution of generation in the queues shows that new capacity is being added disproportionately in the west. The geographic distribution of units by fuel type in the queues, when combined with data on unit age, suggests that reliance on natural gas as a fuel in the east will increase.

PJM Generation Queues

Generation request queues are groups of proposed projects. Queue A was open from February 1997 through January 1998; Queue B was open from February 1998 through January 1999; Queue C was open from February 1999 through July 1999 and Queue D opened in August 1999. After Queue D, a new queue was opened every six months. Queue U will be active through July 31, 2008.[51]

Capacity in generation request queues for the 10-year period beginning in 2007 and ending in 2016 increased by 27,621 MW from 46,272 MW in 2006 to 73,893 MW in 2007. (See Table 3-33.)[52, 53] Queued capacity scheduled for service in 2007 increased from 7,988 MW to 8,939 MW, or 12 percent. Queued capacity scheduled for service in 2008 increased from 9,705 MW to 11,636 MW, or 20 percent. Capacity

50 Values in the tables have been modified slightly because of accounting changes in information databases.

51 The dates of the RTEP feasibility studies were reported as the end dates of the queues in the *2005 State of the Market Report* instead of the actual start and end dates of the queues. Later, queue commencement and expiration dates were changed to reflect the correct dates. This change commenced with the *2006 State of the Market Report*.

52 See the *2006 State of the Market Report* (March 6, 2007), pp. 133-134, for the queues in 2006.

53 The 73,893 MW includes generation with scheduled in-service dates in 2007 and earlier years net of generation that is in-service earlier than scheduled.

in the queues for each of the years 2008 through 2014 also increased in 2007 over 2006. Queued capacity scheduled for service in 2015 and 2016 has not changed. In 2007, no projects were in queues projected to enter service later than 2016.

Table 3-33 Queue comparison (MW): Calendar years 2007 vs. 2006

	MW in the Queue 2006	MW in the Queue 2007	Year-to-Year Change (MW)	Year-to-Year Change
2007	7,988	8,939	951	12%
2008	9,705	11,636	1,931	20%
2009	4,575	10,377	5,802	127%
2010	7,436	11,464	4,028	54%
2011	5,935	17,653	11,718	197%
2012	4,159	5,520	1,361	33%
2013	1,600	1,660	60	4%
2014	0	1,770	1,770	NA
2015	3,234	3,234	0	0%
2016	1,640	1,640	0	0%
Total	46,272	73,893	27,621	NA

Table 3-34 shows the amount of capacity active, in-service, under construction or withdrawn for each queue since the beginning of the Regional Transmission Expansion Plan (RTEP) Process and the total amount of capacity that had been included in each queue. [54]

54 Projects listed as active have been entered in the queue and the next phase can be under construction, in-service or withdrawn. At any time, the total number of projects in the queues is the sum of active projects and under-construction projects.

Table 3-34 Capacity in PJM queues (MW): At December 31, 2007[55]

Queue	Active	In-Service	Under Construction	Withdrawn	Total
A Expired 31-Jan-98	0	8,933	0	18,287	27,220
B Expired 31-Jan-99	0	4,638	0	15,882	20,520
C Expired 31-Jul-99	47	531	0	4,053	4,631
D Expired 31-Jan-00	0	768	0	7,069	7,837
E Expired 31-Jul-00	0	795	0	17,637	18,432
F Expired 31-Jan-01	0	52	0	3,093	3,145
G Expired 31-Jul-01	670	486	525	21,892	23,573
H Expired 31-Jan-02	0	259	443	8,424	9,126
I Expired 31-Jul-02	76	81	0	4,863	5,020
J Expired 31-Jan-03	0	36	155	707	898
K Expired 31-Jul-03	15	124	499	2,068	2,706
L Expired 31-Jan-04	0	66	666	3,548	4,280
M Expired 31-Jul-04	458	96	372	3,662	4,588
N Expired 31-Jan-05	2,413	1,922	158	5,275	9,768
O Expired 31-Jul-05	4,187	248	115	3,339	7,889
P Expired 31-Jan-06	6,433	393	14	2,122	8,962
Q Expired 31-Jul-06	14,225	0	5	1,312	15,542
R Expired 31-Jan-07	17,408	24	11	6,812	24,255
S Expired 31-Jul-07	22,134	20	0	300	22,454
T Expired 31-Jan-08	2,977	0	0	0	2,977
Total	71,043	19,472	2,963	130,345	223,823

Data presented in Table 3-34 show that 70 percent of total in-service capacity from all the queues was from Queues A and B and an additional 11 percent was from Queues C, D and E.[56]

The data presented in Table 3-34 show that for successful projects there is an average time of 1,047 days (i.e., 2.9 years) between entering a queue and the in-service date. The data also show that for withdrawn projects, there is an average time of 693 days (i.e., 1.9 years) between entering a queue and exiting. For each status, there is substantial variability around the average results.

55 The *2007 State of the Market Report* contains all projects in the queue including reratings of existing generating units and energy only resources.

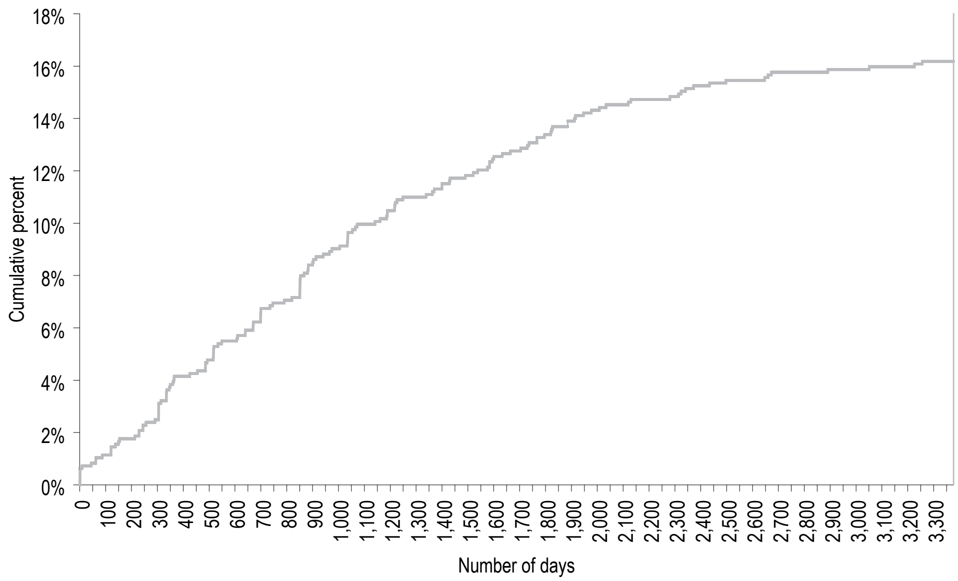
56 The data for Queue T include projects through December 31, 2007.

Table 3-35 Average project queue times: At December 31, 2007

Status	Average (Days)	Standard Deviation	Minimum	Maximum
In-service	1,047	783	0	3,376
Under construction	1,433	455	517	2,524
Withdrawn	693	586	72	3,225
Active	604	379	152	3,255

Figure 3-6 shows the cumulative probability of completion of RTEP projects. The first queue (Queue A) was opened more than 4,000 days ago and the final active project in the A Queue was completed in 2006. The final project was in the queue for 3,376 days and this is the upper limit of Figure 3-6. The data show that about 10.0 percent of all projects in the queue are completed within 1,141 days and about 16.2 percent of the projects are completed within 3,376 days.

Figure 3-6 RTEP project completion probability as function of days in queue



Distribution of Units in the Queues

Table 3-36 shows the RTEP projects under construction or active as of December 31, 2007, by unit type and control zone. Most (93 percent of the MW) of the steam projects (predominantly coal) and most of the wind projects (94 percent of the MW) are outside the Eastern MAAC (EMAAC)[57] and Southwestern MAAC (SWMAAC)[58] locational deliverability areas (LDAs).[59] Most (60 percent of the MW) of the combined-cycle (CC) projects are in EMAAC and SWMAAC. Wind projects account for approximately 25,211 MW of capacity

57 EMAAC consists of the AECO, DPL, JCPL, PECO and PSEG control zones.

58 SWMAAC consists of the BGE and Pepco control zones.

59 See the *2007 State of the Market Report*, Volume II, Appendix A, "PJM Geography" for a map of PJM LDAs.

or 34 percent of the capacity in the queues and CC projects account for 7,306 MW of capacity or 10 percent of the capacity in the queues.[60] Of the total capacity additions, only about 14,019 MW or 19 percent are projected to be in zones that are in EMAAC; about 7,892 MW or 11 percent are projected to be constructed in zones that are in SWMAAC.

Table 3-36 Capacity additions in active or under-construction queues by control zone (MW): At December 31, 2007

	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Steam	Wind	Total
AECO	225	695	9	0	0	650	0	1,579
AEP	0	646	247	144	84	6,059	3,255	10,435
AP	640	600	11	81	0	1,955	2,268	5,555
BGE	0	961	8	0	3,280	0	0	4,249
ComEd	600	835	105	0	280	765	13,049	15,634
DAY	0	37	2	0	0	1,300	983	2,322
Dominion	1,633	1,235	148	94	1,944	280	0	5,334
DPL	0	305	23	0	0	653	1,598	2,579
JCPL	1,261	194	40	1	0	0	0	1,496
Met-Ed	47	1,200	66	0	0	0	0	1,313
PECO	550	4,540	6	0	140	0	3	5,239
PENELEC	0	153	12	32	0	310	2,778	3,285
Pepco	1,250	2,388	5	0	0	0	0	3,643
PPL	0	42	38	140	1,018	5,402	1,277	7,917
PSEG	1,100	1,909	74	0	43	0	0	3,126
UGI	0	0	0	0	0	300	0	300
Total	7,306	15,740	794	492	6,789	17,674	25,211	74,006

Table 3-37 shows existing generators by unit type and control zone. Existing steam (mainly coal and residual oil) and nuclear capacity are distributed across control zones.

A potentially significant change in the distribution of unit types within the PJM footprint is likely as a combined result of the location of generation resources in the queue (Table 3-37) and the location of units likely to retire. In both the EMAAC and SWMAAC LDAs, the capacity mix is likely to shift to more natural gas-fired CC and combustion turbine (CT) capacity. Elsewhere in the PJM footprint, continued reliance on steam (mainly coal) seems likely.

60 Since wind resources cannot be dispatched on demand, PJM rules require that the unforced capacity of these resources be derated by 80 percent until actual generation data are available. The derating of 25,200 MW of wind resources means that only 53,800 MW of capacity are effectively in the queue of the 74,000 MW currently active in the queues.

Table 3-37 Existing PJM capacity 2007 (By zone and unit type (MW))

	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Steam	Wind	Total
AECO	155	528	14	0	0	1,108	8	1,813
AEP	4,361	3,577	0	1,008	2,093	21,711	0	32,750
AP	1,129	1,159	43	80	0	7,862	81	10,354
BGE	0	872	0	0	1,735	2,793	0	5,400
ComEd	1,790	6,172	0	0	11,448	6,916	343	26,669
DAY	0	1,316	44	0	0	4,079	0	5,439
DLCO	272	45	0	0	1,630	3,524	0	5,471
Dominion	2,515	3,213	105	3,321	3,459	8,332	0	20,945
DPL	1,088	801	86	0	0	1,780	0	3,755
External	0	100	0	0	0	5,605	0	5,705
JCPL	1,569	1,216	6	333	619	10	0	3,753
Met-Ed	1,984	417	0	19	786	817	0	4,023
PECO	2,497	1,498	6	1,618	4,492	2,022	0	12,133
PENELEC	0	332	50	476	0	6,805	119	7,782
Pepco	1,134	1,321	0	0	0	4,774	0	7,229
PPL	1,674	613	39	568	2,003	5,697	112	10,706
PSEG	2,849	2,975	13	8	3,353	2,264	0	11,462
Total	23,017	26,155	406	7,431	31,618	86,099	663	175,389

Table 3-38 shows the age of PJM generators by unit type. If the age profile of steam units in PJM accurately represents the future age profile, significant and disproportionate retirements of steam units will occur within the next 10 to 20 years. While steam units comprise 49 percent of all current MW, steam units 40 years of age and older comprise 87 percent of all MW 40 years of age and older and nearly 97 percent of such MW if hydroelectric is excluded from the total. Approximately 6,305 MW of steam units 40 years of age and older are located in EMAAC and SWMAAC.

Table 3-38 PJM capacity age (MW)

Age (years)	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Steam	Wind	Total
Less than 10	17,470	15,893	79	119	0	1,280	663	35,504
10 to 20	4,985	3,012	87	58	3,533	7,096	0	18,771
20 to 30	2	86	53	3,109	14,628	8,612	0	26,490
30 to 40	560	6,274	87	703	13,457	39,111	0	60,192
40 to 50	0	890	96	2,150	0	19,976	0	23,112
50 to 60	0	0	4	354	0	9,174	0	9,532
60 to 70	0	0	0	107	0	850	0	957
70 to 80	0	0	0	538	0	0	0	538
80 to 90	0	0	0	135	0	0	0	135
90 to 100	0	0	0	129	0	0	0	129
100 and over	0	0	0	29	0	0	0	29
Total	23,017	26,155	406	7,431	31,618	86,099	663	175,389

There are potentially significant implications for future congestion, the role of firm and interruptible gas supply and natural gas supply infrastructure, if older steam units in the EMAAC and SWMAAC LDAs are replaced by units burning natural gas. Table 3-39 shows that in the EMAAC LDA, gas-consuming unit types (CC and CT facilities) dominate the capacity additions, accounting for approximately 77 percent of the slated capacity additions. Steam additions (coal) account for about 9 percent of the MW and wind projects account for 11 percent of the MW in the queue for the EMAAC LDA. It should be noted that the wind capacity in Table 3-39 is reported at nameplate capacity and not reduced to 20 percent of nameplate. Nuclear and gas capacity comprise the capacity additions in the SWMAAC LDA.

Table 3-39 Capacity additions in active or under-construction queues by LDA (MW): At December 31, 2007

	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Steam	Wind	Total
EMAAC	3,136	7,643	152	1	183	1,303	1,601	14,019
Non-MAAC	2,873	3,353	513	319	2,308	10,359	19,555	39,280
SMAAC	1,250	3,349	13	0	3,280	0	0	7,892
WMAAC	47	1,395	116	172	1,018	6,012	4,055	12,815
PJM Total	7,306	15,740	794	492	6,789	17,674	25,211	74,006

Table 3-40 shows the effect that the new generation in the queues would have on the existing generation mix, assuming that all non-hydroelectric generators in excess of 40 years of age retire by 2016. In 2016, CC and CT generators would account for 59 percent of EMAAC generation, an increase of 13 percentage points from 2007 levels. Accounting for the fact that about 700 MW of steam units over 40 years old are gas-fired, the result would be an increase in the proportion of gas-fired capacity in EMAAC from about 38 percent to about 53 percent. This proportion of gas-fired capacity in EMAAC would increase to 54 percent if the 80 percent reduction for wind capacity is taken into account for EMAAC, meaning that the effective capacity additions are 12,738 MW.

The exact expected role of gas-fired generation depends largely on projects in the queues. Two coal projects in EMAAC totaling 1,280 MW face substantial site-related issues. There is a planned addition of 3,280 MW of nuclear capacity in SWMAAC.

Without the planned coal-fired capability in EMAAC, new gas-fired capability would represent 85 percent of all new capability in EMAAC and 94 percent when the 80 percent reduction for wind capability is included. In 2016 this would mean that CC and CT generators would comprise 61.2 percent of total capability in EMAAC.

Without the planned nuclear capability in SWMAAC, new gas-fired capability would represent nearly 100 percent of all new capability in the SWMAAC. In 2016 this would mean that CC and CT generators would comprise 54.5 percent of total capability in SWMAAC.

Table 3-40 Comparison of generators 40 years and older with slated capacity additions (MW): Through 2016[61]

Area	Unit Type	Capacity of Generators 40 Years or Older	Percent of Area Total	Capacity of Generators All Ages	Percent of Area Total	Additional Capacity through 2016	Estimated Capacity 2016	Percent of Area Total
EMAAC	Combined cycle	0	0.0%	8,158	24.8%	3,136	11,294	26.4%
	Combustion turbine	606	10.3%	7,018	21.3%	7,643	14,055	32.9%
	Diesel	36	0.6%	125	0.4%	152	241	0.6%
	Hydroelectric	1,683	28.7%	1,959	6.0%	1	1,960	4.6%
	Nuclear	0	0.0%	8,464	25.7%	183	8,647	20.2%
	Steam	3,548	60.4%	7,184	21.8%	1,303	4,939	11.6%
	Wind	0	0.0%	8	0.0%	1,601	1,609	3.8%
	EMAAC Total	5,873	100.0%	32,916	100.0%	14,019	42,745	100.0%
Non-MAAC	Combined cycle	0	0.0%	10,067	9.4%	2,873	12,940	10.2%
	Combustion turbine	27	0.1%	15,582	14.5%	3,353	18,908	15.0%
	Diesel	39	0.2%	192	0.2%	513	666	0.5%
	Hydroelectric	1,335	6.2%	4,409	4.1%	319	4,728	3.7%
	Nuclear	0	0.0%	18,630	17.4%	2,308	20,938	16.6%
	Steam	20,250	93.5%	58,029	54.1%	10,359	48,138	38.1%
	Wind	0	0.0%	424	0.4%	19,555	19,979	15.8%
	Non-MAAC Total	21,651	100.0%	107,333	100.0%	39,280	126,297	100.0%
SWMAAC	Combined cycle	0	0.0%	1,134	9.0%	1,250	2,384	13.5%
	Combustion turbine	59	2.1%	2,193	17.4%	3,349	5,483	31.0%
	Diesel	0	0.0%	0	0.0%	13	13	0.1%
	Hydroelectric	0	0.0%	0	0.0%	0	0	0.0%
	Nuclear	0	0.0%	1,735	13.7%	3,280	5,015	28.3%
	Steam	2,757	97.9%	7,567	59.9%	0	4,810	27.2%
	Wind	0	0.0%	0	0.0%	0	0	0.0%
	SWMAAC Total	2,816	100.0%	12,629	100.0%	7,892	17,705	100.0%
WMAAC	Combined cycle	0	0.0%	3,658	16.2%	47	3,705	11.7%
	Combustion turbine	198	4.8%	1,362	6.1%	1,395	2,559	8.1%
	Diesel	25	0.6%	89	0.4%	116	180	0.6%
	Hydroelectric	424	10.4%	1,063	4.7%	172	1,235	3.9%
	Nuclear	0	0.0%	2,789	12.4%	1,018	3,807	12.0%
	Steam	3,445	84.2%	13,319	59.2%	6,012	15,886	50.2%
	Wind	0	0.0%	231	1.0%	4,055	4,286	13.5%
	WMAAC Total	4,092	100.0%	22,511	100.0%	12,815	31,658	100.0%
All Areas	Total	34,432		175,389		74,006	218,405	

61 Percents shown in Table 3-40 are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

2007 High-Load Events, Scarcity and Scarcity Pricing Events

In 2005 it was recognized that changing market dynamics created by PJM's expanded footprint, along with PJM's continued need for non market emergency mechanisms to maintain system reliability under conditions of scarcity, had created a need for an administrative scarcity pricing mechanism.[62] PJM entered into a settlement in 2005 that was approved by the FERC and resulted in the implementation of administrative scarcity pricing rules in 2006.[63] August 8, 2007, was the first time that the administrative scarcity pricing rules were triggered. Table 3-41 provides the scarcity pricing events that occurred on August 8, 2007.

Table 3-41 2007 Scarcity pricing events[64]

	08-Aug-07	
Scarcity Region	Start	Stop
Bedington - Black Oak	1505	1812
Mid-Atlantic	1555	1733

PJM's administrative scarcity pricing mechanism was designed to ensure the appropriate tradeoff between limiting local market power and allowing market prices to reflect scarcity conditions.[65] The administrative rules initiate scarcity pricing when PJM takes specific, non market, emergency administrative actions to maintain system reliability under conditions of high load in prespecified areas within PJM. These emergency actions include emergency energy purchase request events, maximum emergency generation events, manual load dump events and voltage reduction events. When PJM implements any of the identified emergency procedures, any offer capping of units in the affected area is lifted and the LMP of the entire affected area is set equal to the highest-priced offer of a unit dispatched at the time.

The MMU's review of 2007 market results indicate that PJM's use of specific emergency procedures was an indicator of scarcity conditions. The analysis also leads to the recommendation that PJM's scarcity pricing mechanism be modified to incorporate a phased approach to scarcity and to incorporate nodal scarcity price signals and that PJM define additional scarcity pricing regions.

Definitions and Methodology

Scarcity exists when the total demand for power approaches the generating capability of the system. Scarcity pricing means that market prices reflect the fact that the system is close to its available capacity. Under scarcity conditions, competitive prices may exceed short-run marginal costs. Under the current PJM rules, high prices result from high offers by individual generation owners for specific units when the system is close to its available capacity. These offers give the aggregate energy supply curve its steep upward sloping tail.[66] As demand increases and units with higher offers are required to meet demand, prices increase. This dynamic may be limited if all units with high offers are subject to offer capping for local market power. In that case, an explicit decision to lift offer capping must be based on a determination that scarcity exists in a defined area. Under the scarcity pricing provisions in the Tariff, that determination is made when PJM takes identified emergency actions. Scarcity pricing results, with the scarcity price based on the highest offer of an operating unit.

62 See the *2005 State of the Market Report*, "Scarcity" (March 8, 2006), pp. 145-150.

63 114 FERC ¶ 61,076 (2006).

64 See PJM. "Manual 13: Emergency Operations," Revision 27 (Effective September 5, 2006), p. 12.

65 114 FERC ¶ 61,076 (2006).

66 See the *2007 State of the Market Report*, Volume II, Section 2, "Energy Market, Part 1".

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 as an offset to capacity market offers, 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.

The challenge is to translate these basic guidelines about scarcity pricing into a consistent set of market rules. The MMU analysis of scarcity constitutes a step toward a comprehensive analysis of scarcity. The MMU recommendations regarding scarcity pricing represent a step toward defining market rules.

In order to proceed with the analysis, terms must be carefully defined so that the results can be interpreted and so that the next steps in the analysis can be taken.

A high-load event is defined to exist when hourly demand, including the day-ahead operating reserve target, equals 90 percent or more of total, within-hour supply in the absence of non market administrative intervention. [67]

Scarcity is defined to exist when hourly demand, including the day-ahead operating reserve target, is greater than, or equal to, total, within-hour supply excluding the impact of non market administrative intervention. Scarcity can exist at varying levels of severity, reflected by the degree to which load plus the reserve requirement exceeds within-hour supply, excluding the impact of non market administrative actions. The more emergency resources and actions that are needed to maintain system reliability, the more severe the scarcity event.

Within-hour, economic resources include the lesser of the hourly available ramp or remaining non-emergency capacity of synchronized resources and the lesser of hourly available ramp or available non-emergency capacity of non-synchronized resources with less than a one-hour startup time.[68]

The total system hourly operating reserve target is calculated based on the sum of the control-zone-specific, 30-minute, day-ahead reserve requirements as defined by PJM.[69] The definitions of high-load and scarcity events do not account for potential violations of aggregate, regional or zonal, 10-minute primary reserve requirements or 30-minute operating reserve targets. The definitions also do not account for utility or

67 See PJM. "Manual 10: Pre-Scheduling Operations," Revision 20 (Effective June 15, 2006), pp. 21-25. See also PJM. "Manual 11: Scheduling Operations," Revision 29 (Effective August 11, 2006), pp. 87-96.

68 The methodology used to determine within-hour resources for this analysis tends to overestimate within-hour resources. For example, a unit's total within-hour ramp is presumed available from the first five-minute interval to the last, rather than being limited to the actual five-minute ramp rate within the hour. This means that a unit with a 100 MW ramp (i.e., with 100 MW capacity) is assumed to provide an average of 100 MW every minute of the hour. This methodology also overestimates available resources relative to the primary reserve requirement, as primary reserve resources must be available on less than a 30-minute basis. This measure also ignores transmission constraints that may limit deliverability to meet local load.

69 See PJM. "Manual 10: Pre-Scheduling Operations," Revision 20 (Effective June 15, 2006), pp. 21-25. See also PJM. "Manual 11: Scheduling Operations," Revision 29 (Effective August 11, 2006), pp. 87-96.

participant-specific actions, such as interruption of non-firm load in accordance with applicable contracts or demand-side management measures that may be used to maintain system integrity.[70] Nonetheless, the net within-hour resource calculation provides a reasonable measure of overall system supply-demand balance. The basis of the control zone reserve requirements is shown in Table 3-42.

Table 3-42 Zone-specific operating reserve targets and requirements:[71, 72] Calendar year 2007

Control Zone	Region	Operating (Day Ahead)	Primary (Real Time)	Synchronized Reserve	Regulation
AP	Western	6% forecast load	3% forecast load	1.5% peak load	1% peak
AEP	Western	6% forecast load	3% forecast load	1.5% peak load	1% peak
DAY	Western	6% forecast load	3% forecast load	1.5% peak load	1% peak
ComEd	Western	MAIN ARS + Regulation	MAIN ARS	50% MAIN ARS	1% peak
Dominion	Southern	6% forecast load	VACAR ARS%	VACAR ARS%	1% peak
DLCO	Western	6% forecast load	3% forecast load	1.5% peak load	1% peak
PJM	Mid-Atlantic	Load dependent	1700 MW	Largest unit	1% peak

Non market, administrative tools available to PJM to ensure that demand does not exceed supply include calling for full emergency load response,[73] recalls of noncapacity-backed exports, loading of maximum emergency generation, voltage reductions,[74] emergency power purchases and manual load dump.[75] Of these steps, the last four are defined in the PJM Tariff as triggers for scarcity pricing events.[76]

In the MMU analysis, non market administrative tools applied by PJM in a given hour are used to adjust the measures of supply and demand to calculate the net supply condition that would have existed absent PJM intervention. The exception is the level of recallable energy exports from capacity resources. These are not included because PJM does not recall such energy in practice, for a variety of reasons. When PJM called full emergency load response, the associated load reduction is added to demand when calculating within-hour net resources. PJM-called emergency load response events in 2007 are shown in Table 3-43. When PJM directed the loading of maximum emergency generation, the value of the hourly maximum emergency generation loaded is subtracted from PJM total within-hour supply when calculating within-hour resources. When a maximum emergency alert is declared and the maximum emergency capacity is counted toward operating reserve targets by PJM, the added capacity is considered to be noneconomic for purposes of this analysis. Table 3-44 shows that maximum emergency generation alerts were declared and maximum

70 Only PJM-called interruptions of non-firm load in accordance with applicable contracts and PJM-called emergency demand response are used in the calculations.

71 See PJM. "Manual 13: Emergency Operations," Revision 27 (Effective September 5, 2006), p. 12. ARS is automatic reserve sharing.

72 PJM triggers the "Contingency (also called Primary) Reserve Emergency Procedures" on the Mid-Atlantic Region based on a contingency or primary reserve requirement of 1,700 MW because of potential deliverability issues. Contingency or primary reserve requirements for the Reliability*First* Corporation (RFC) portion of the PJM footprint are 150 percent of the largest generators.

73 At the time of a call for full emergency load response, a PJM dispatcher also issues a NERC "Energy Emergency Alert Level 2" (EEA2) via the Reliability Coordinator Information System (RCIS) to ensure that all reliability authorities clearly understand potential and actual PJM system emergencies if one has not already been issued concurrent with the issuance of active load management curtailables/full emergency load response (formerly known as ALM). NERC EEA2 is issued when the following has occurred: Public appeals to reduce demand, voltage reduction and interruption of non-firm load in accordance with applicable contracts, demand-side management/active load management or utility load conservation measures. See PJM. "Manual 13: Emergency Operations," Revision 27 (Effective September 5, 2006), p. 19.

74 A voltage reduction warning (i.e., not an action) is evidence that the system is running out of available resources. A voltage reduction warning "is implemented when the available synchronized reserve capacity is less than the synchronized reserve requirement, after all available secondary and primary reserve capacity (except restricted maximum emergency capacity) is brought to a synchronized reserve status and emergency operating capacity is scheduled from adjacent systems." See PJM. "Manual 13: Emergency Operations," Revision 33 (Effective January 1, 2008), p. 24. Note that curtailment of nonessential building load is implemented prior to, or at this same time as, a voltage reduction action.

75 See PJM. "Manual 13: Emergency Operations," Revision: 27 (Effective September 5, 2006), p. 29: "The PJM RTO is normally loaded according to bid prices; however, during periods of reserve deficiencies, other measures must be taken to maintain reliability."

76 See PJM. "Open Access Transmission Tariff (OATT)," Sixth Revised Volume No. 1, Third Revised Sheet No. 402A.01 (Effective January 27, 2006).

emergency generation was loaded in one or more zones on August 8, 2007. When PJM called a voltage reduction, the value of the voltage reduction, in MW, is added to demand when calculating within-hour net resources. As shown in Table 3-45, PJM called a voltage reduction in one or more zones on August 8, 2007.

Table 3-43 PJM-called ALM: August 8, 2007[77]

	08-Aug-07	
	Effective Start	Stop
Short lead time Mid-Atlantic (BGE and Pepco sub-regions)	1320	1835
Long lead time (1 to 2 Hrs) Mid-Atlantic (BGE and Pepco sub-regions)	1344	1835
Short lead time Mid-Atlantic	1630	1750
Long lead time (1 to 2 Hrs) Mid-Atlantic	1408	1750
Short lead time Dominion		
Long lead time (1 to 2 Hrs) Dominion	1408	1835

Table 3-44 PJM-declared, maximum emergency events and maximum emergency generation loaded: August 8, 2007

	08-Aug-07	
	Start	Stop
Event declared BGE	1233	1812
Generation loaded BGE	1233	1812
Event declared Pepco	1233	1812
Generation loaded Pepco	1233	1812
Event declared Southern	1505	1812
Generation loaded Southern	1505	1812
Event declared Mid-Atlantic	1531	1733
Generation loaded Mid-Atlantic	1557	1733

77 While ALM has officially been changed to full emergency load response, operators were still, as of August 8, 2007, logging PJM-called emergency demand response as ALM.

Table 3-45 PJM-declared voltage reduction events: August 8, 2007

	08-Aug-07	
	Start	Stop
Mid-Atlantic Region	1555	1709
BGE and Pepco	1555	1759

2007 Results: High-Load and Scarcity Hours

As defined above, there were 157 high-load hours in 2007, of which 21 occurred in June, 40 occurred in July and 96 occurred in August. This number of high-load hours is more than twice the 70 high-load hours in 2006. Within these 157 hours, there were three hours, the hours beginning 1500 through 1700 on August 8, that met the criteria for potential within-hour scarcity.[78] PJM triggered its scarcity pricing events between 1505 and 1812. In 2006, 10 hours met the criteria for potential within-hour scarcity, but no scarcity events were triggered. There were 25 days in 2007 that met the criteria of a high-load day, up from the seven days recorded in 2006. The high-load days in 2007 were: June 1, 26 and 27; July 9, 10, 18, 26, 27, 30 and 31; and August 1 to 3, 6 to 10, 13, 15 to 17, 24, 28 and 29.[79]

Figure 3-7 shows the hourly loads of each high-load day relative to the average hourly summer load for 2007 and the hourly load of August 8, 2007.

78 Scarcity is considered to exist when hourly demand, including a total operating reserve requirement, is greater than, or equal to, total, within-hour supply in the absence of non market administrative intervention.

79 A high-load event is defined as a period during which real-time system load, plus the total of the system day-ahead operating reserve target, approaches a level that, in the absence of non market administrative intervention by PJM or a transmission zone, requires the use of 90 percent or more of total within-hour, available non-emergency resources in two or more hours in a given 24-hour period.

Figure 3-7 High-load day hourly load and summer average hourly load: June 2007 through August 2007

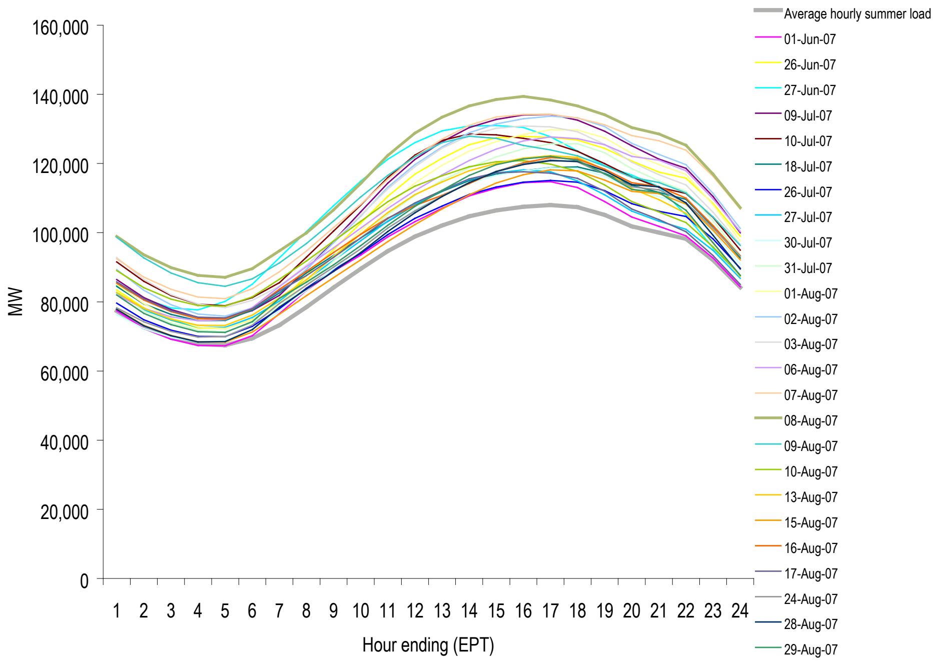


Figure 3-8 shows the net hourly difference between within-hour, available, non-emergency resources and total aggregate hourly demand including the day-ahead operating reserve target for June 1, 26, and 27, 2007.[80, 81] Figure 3-8 shows the net hourly difference between within-hour, available, non-emergency resources and total aggregate hourly demand, including the day-ahead operating reserve requirement for July 9, 10, 18, 26, 27, 30, and 31, 2007. Figure 3-9 shows the net hourly difference between within-hour, available, non-emergency resources and total aggregate hourly demand, including the day-ahead operating reserve requirement for August 1 to 3, 6 to 10, 13, 15 to 17, 24, 28, and 29, 2007. In the figures, hours that meet the high-load definition are indicated by yellow bars, hours that meet the scarcity definition are indicated by red bars, and all other hours are indicated by green bars.

PJM took emergency action or made use of emergency resources on some of the days identified as high load. For example, PJM declared maximum emergency generation alerts for August 7, through August 9, 2007, for one or more zones. During this period available maximum emergency capacity was included in the calculation of operating reserve by PJM. On August 8, absent the inclusion of this capacity, PJM would have missed its day-ahead operating reserve target in one or more control zones for one or more hours. PJM operations recorded primary reserve warnings in one or more zones on August 8, 2007.

80 Load, as used here, is based on hourly eMTR loads in each hour, which are the simple average of the 12 five-minute interval loads in the hour for the total system.

81 See PJM. "Manual 10: Pre-Scheduling Operations," Revision 20 (Effective June 15, 2006), pp. 21-25. See also PJM. "Manual 11: Scheduling Operations," Revision 29 (Effective August 11, 2006), pp. 87-96.

Figure 3-8 Net within-hour resources: June 1, 26, and 27, 2007

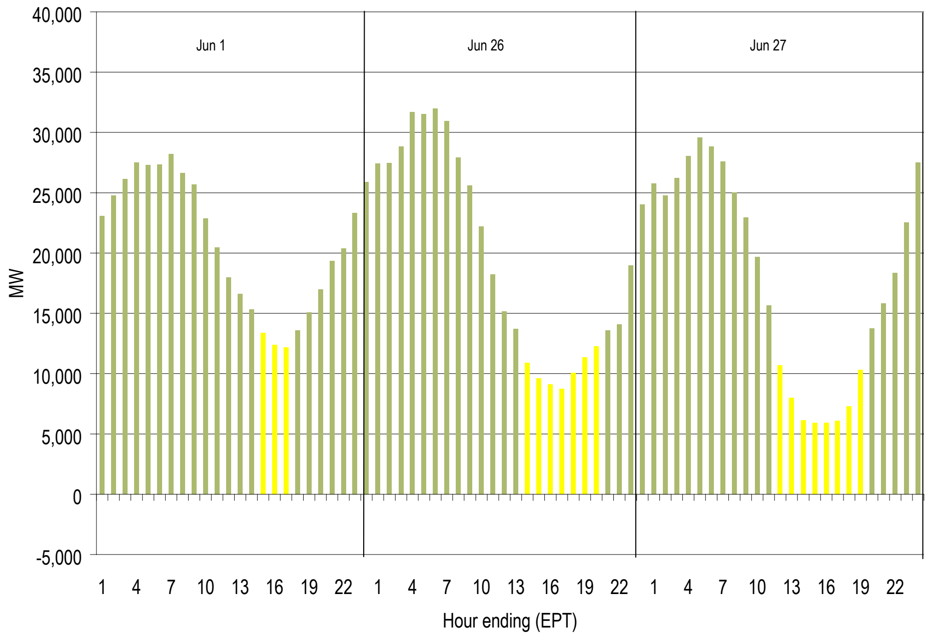


Figure 3-9 Net within-hour resources: July 9, 10, 18, 26, 27, 30, and 31, 2007

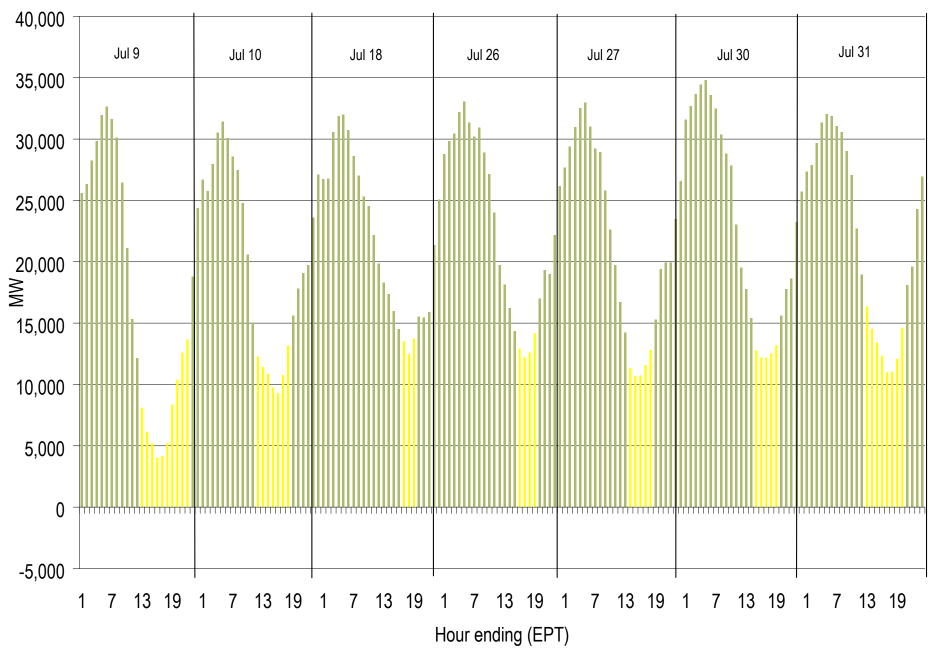


Figure 3-10 Net within-hour resources: August 1 to 3, August 6 to 10, August 13, August 15 to 17, August 24, 28, and 29, 2007

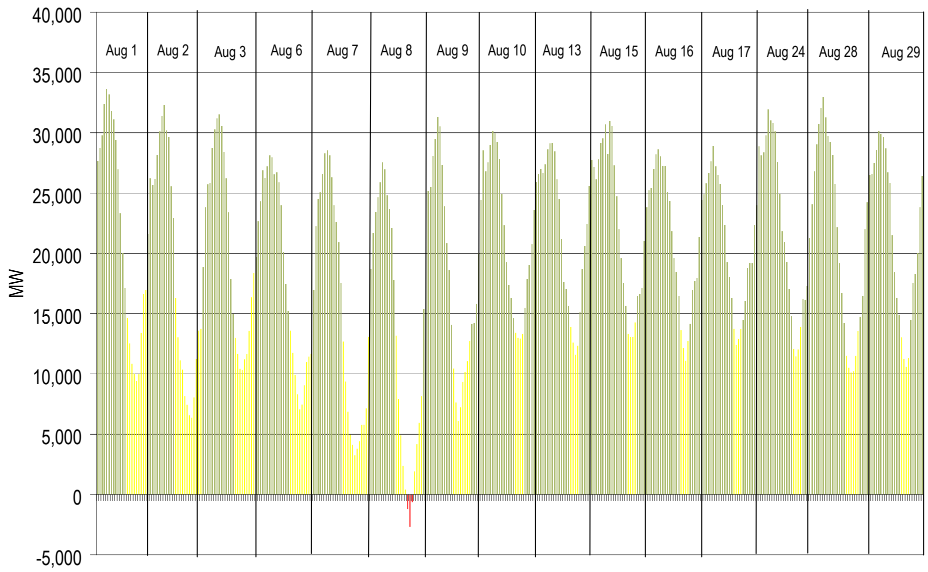
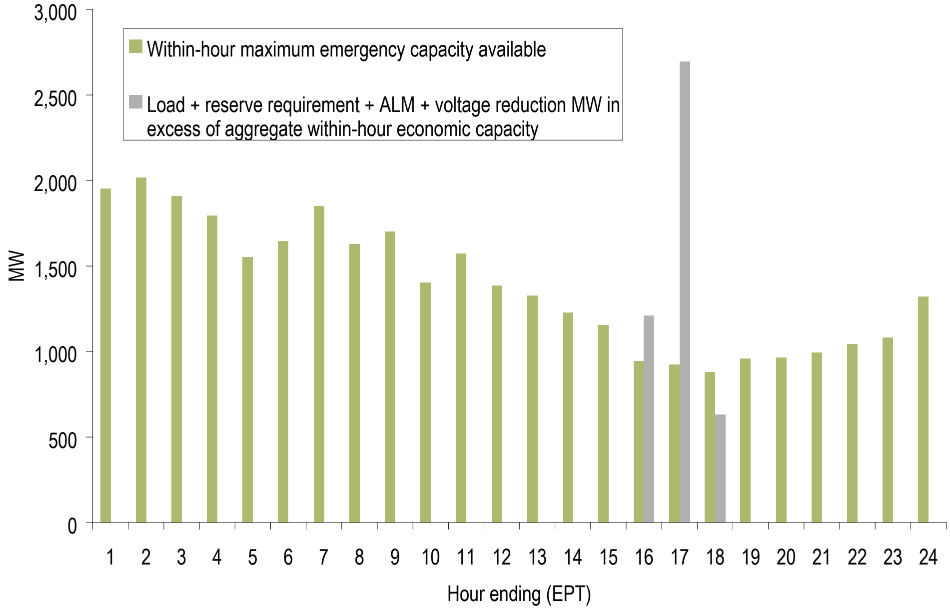


Figure 3-10 shows that hours ending 1600, 1700 and 1800 had negative net within-hour resources and therefore met the scarcity definition. Figure 3-11 shows the within-hour, available maximum emergency generation capacity, by hour and total hourly demand in excess of total within-hour economic supply for August 8. On that day, on an hourly aggregate basis, total demand, including the day-ahead operating reserve target, voltage reduction MW and ALM taken, caused PJM to be in a scarcity condition, as defined here, in hours beginning 1500, 1600 and 1700. PJM triggered its scarcity pricing events of August 8, 2007, during these same hours. (See Table 3-41.)

Figure 3-11 Within-hour maximum emergency capacity relative to hourly demand in excess of within-hour economic resources: August 8, 2007



Maximum emergency generation is generation capacity that PJM considers to be above the maximum economic level.[82] In concept, maximum emergency generation represents temporary MW additions to capacity made possible by operating a generator above its maximum economic capacity. In practice, the definition of maximum emergency generation in PJM is unclear and has been expanded beyond this scope to include environmental, fuel, temporary emergency conditions at the unit and other conditions which are declared to limit the availability of all or a portion of a unit's capacity. However, according to the PJM Tariff, during maximum emergency generation alerts the only capacity that can be designated as maximum emergency must fall into one of the following categories:

- Environmental Limits. If the unit has a hard cap on its run hours imposed by an environmental regulator that will temporarily significantly limit its availability.

- Fuel Limits. If physical events beyond the control of the unit owner result in the temporary interruption of fuel supply, and there is limited onsite fuel storage. A fuel supplier's exercise of a contractual right to interrupt supply or delivery under an interruptible service agreement does not qualify as an event beyond the control of the unit owner.

- Temporary Emergency Conditions at the Unit. If temporary emergency physical conditions at the unit significantly limit its availability.

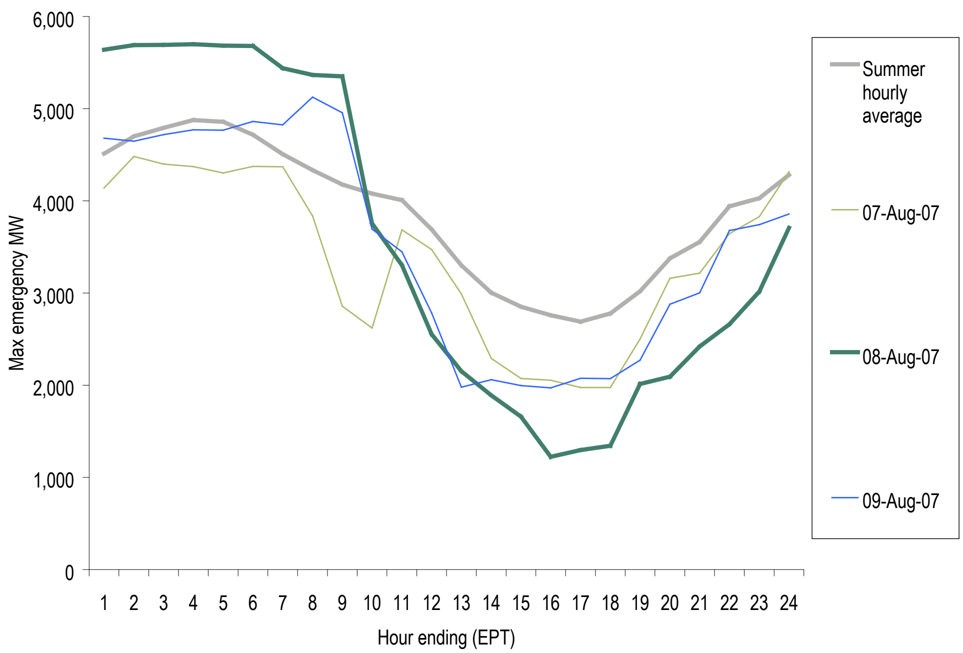
- Temporary MW Additions. If a unit can provide additional MW on a temporary basis by oil topping, boiler overpressure, or similar techniques and such MW are not ordinarily otherwise available.[83]

82 See PJM. "Manual 13: Emergency Operations," Revision 27 (Effective September 5, 2006), p. 34.
83 See PJM. "Manual 13: Emergency Operations," Revision 27 (Effective September 5, 2006), pp. 73-74.

In the event of a declaration of a maximum emergency generation alert, generation owners are required, within PJM-specified time frames, to re-designate any maximum emergency capacity that does not meet the above criteria as economic capacity.[84]

Figure 3-12 shows the hourly comparison of declared maximum emergency capacity on days when maximum emergency generation alerts had been issued by PJM in one or more zones. On average, the capacity declared as maximum emergency generation capacity fell, consistent with the scarcity rules, during the high-load period of each day, relative to the summer average in each hour.

Figure 3-12 Comparison of hourly maximum emergency capacity on maximum generation alert days to the hourly summer average maximum emergency capacity: Summer 2007



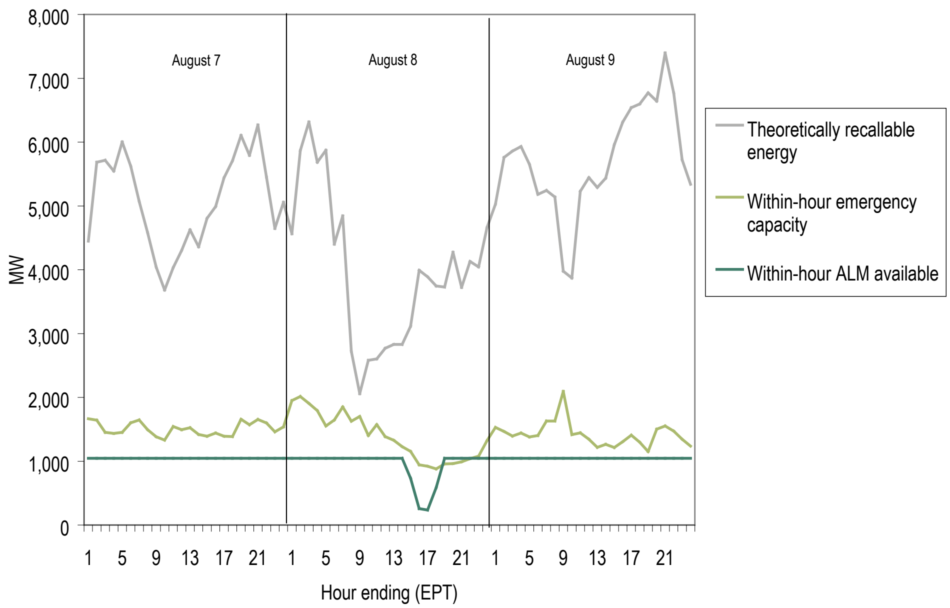
With the exception of potential emergency energy purchases and voltage reduction effects, Figure 3-13 shows each hour's within-hour available emergency resources for August 7, through August 9, 2007. The figure provides estimates of hourly recallable energy, within-hour available maximum emergency capacity and net remaining short-notification, emergency load response capacity.

Maximum emergency capacity available includes the lesser of the hourly available ramp or remaining emergency capacity from synchronized resources and the lesser of hourly available ramp or available capacity from non-synchronized, maximum emergency-only resources with less than a one-hour startup

84 See PJM. "Manual 13: Emergency Operations," Revision 27 (Effective September 5, 2006), p. 74: "On days when PJM has declared, prior to 1800 hours on the day prior to the operating day, a Maximum Emergency Generation Alert for the entire PJM Control Area or for specific Control Zones or Scarcity Pricing Regions, the only units for which all of part of their capability may be designated as Maximum Emergency are those that meet the criteria described above. Should PJM declare a Maximum Generation Alert during the operating day for which the alert is effective, generation owners will be responsible for removing any unit availability from the Maximum Generation category that does not meet the above criteria within 4 hours of the issuance of the alert. PJM will make a mechanism available to participants by which they may inform PJM of their generating capability that meets the above criteria and indicate which of the criteria it meets."

time.[85] For purposes of determining the amount of energy available for emergency recall in a particular hour, total generation from delisted units is subtracted from exports in each hour. The result is a measure of recallable, export MW from PJM capacity resources. This calculated value is likely to be significantly larger than the total energy that could actually be recalled in an emergency. During times of significantly high load on a regional scale, if PJM operators believe that recalling energy could trigger reciprocal recalls from affected control areas, they will likely not recall the energy. All within-hour available generation values reflect available outage information. On the days in question, the most significant potential source of noneconomic capacity was available within-hour maximum emergency generation.

Figure 3-13 Within-hour emergency resources: August 7, to August 9, 2007



The peak PJM demand in 2007 was 139,428 MW in the hour ending 1600 on August 8, 2007. The peak PJM demand in 2006 was 144,644 MW in the hour ending 1700 on August 2, 2006. Despite the lower peak demand on August 8, 2007, the system was, on a net resource basis, tighter in 2007 than it had been on August 2, 2006. The difference in available resources is related, in part, to the level of outages on August 8, 2007, relative to those observed on August 2, 2006. Figure 3-14 provides the hourly MW of capacity forced out of service on August 8, 2007, and August 2, 2006. On an average hourly basis, August 8, 2007, had 2,726 MW more in forced outages than August 2, 2006. On an average hourly basis, the summer of 2007 had 1,126 MW more in forced outages than the summer of 2006.

85 The methodology used to determine within-hour resources for this analysis tends to overestimate within-hour resources. For example, a unit's total within-hour ramp is presumed available from the first five-minute interval to the last, rather than being limited to the actual five-minute ramp rate within the hour. This means that a unit with a 100 MW ramp (i.e., with 100 MW capacity) is assumed to provide an average of 100 MW every minute of the hour. This methodology also overestimates available resources relative to the primary reserve requirement as primary reserve resources must be available on less than a 30-minute basis.

Figure 3-14 Within-hour total forced outages: August 2, 2006, vs. August 8, 2007

2007 Scarcity Pricing Events

Four emergency messages trigger administrative scarcity pricing under the PJM Tariff. (See Table 3-46.)[86, 87] Two of these triggers were implemented in one or more zones on August 8, 2007. As shown in Table 3-44, PJM called for maximum emergency generation to be loaded in two contiguous transmission zones that are part of the Mid-Atlantic Scarcity Region (BGE and Pepco) between 1233 and 1812, in the entire the Mid-Atlantic Scarcity Pricing Region between 1557 and 1733 and in the Southern Region between 1505 and 1812. As shown in Table 3-45, PJM called for voltage reductions in two contiguous transmission zones that are part of the Mid-Atlantic Scarcity Pricing Region (BGE and Pepco) between 1555 and 1759 and in the entire Mid-Atlantic Scarcity Pricing Region between 1555 and 1709.

Based on these triggers for scarcity pricing, there were two concurrent scarcity pricing events declared by PJM on August 8, 2007: a scarcity pricing event for the Bedington — Black Oak Scarcity Pricing Region between 1505 and 1812 and a scarcity pricing event for the Mid-Atlantic Scarcity Pricing Region between 1555 and 1733. (See Table 3-41.)

86 "Maximum emergency generation loaded" covers the first three trigger events: a) Begin to dispatch online generators, which are partially designated as maximum emergency, into emergency output levels; b) Begin to dispatch online generators, which are designated entirely as maximum emergency, above their designated minimum load points, if they are currently online and operating at their minimum load points because of restrictive operating parameters associated with the generators; and c) Begin to dispatch any offline generators that are designated entirely as maximum emergency and that have start times plus notification times less than or equal to 30 minutes.

87 114 FERC ¶ 61,076 (2006).

Table 3-46 Scarcity-related emergency messages

Emergency Message	Description
Max emergency gen loaded	The purpose is to increase generation above the normal economic limit.
Voltage reduction	A request to reduce distribution level voltage by 5%, which provides load relief.
Emergency energy purchase	This is a request by PJM for emergency purchases of energy. PJM will select which offers are accepted based on price and expected duration of the need. This request is typically issued at the Max Emergency Generation emergency procedure step.
Manual load dump	The request to disconnect firm customer load (rotating blackouts). This is issued when additional load relief is needed and all other possible procedures have been exhausted. Target: Electricity Distribution Companies

Current Issues with Scarcity Implementation

While PJM's triggers for administrative scarcity pricing are reasonable measures of scarcity conditions, there are indications, based on the MMU analysis of 2007 market results, that PJM's current set of scarcity pricing rules need refinement. In addition, PJM should consider creating a mechanism for defining new scarcity pricing regions in real time if system conditions warrant.

In 2007, PJM did declare a scarcity pricing event for the hours identified by the MMU analysis during which supply was less than, or equal to, demand. This represents a clear improvement over 2006. The issues are whether there should be stages of scarcity pricing leading to the current definition of scarcity, whether scarcity pricing regions were defined correctly and whether a more nodal scarcity pricing mechanism is more consistent with LMP.

PJM was able to use emergency resources to meet operational goals, declaring a maximum emergency alert, which resulted in the inclusion of maximum emergency generation resources in operational reserve and the calling of emergency demand-response resources, without triggering a scarcity event. Had the use of emergency demand-response resources been a trigger, the scarcity event would have started as early as 1408 in the Mid-Atlantic Scarcity Pricing Region and ended as late as 1750.

There is a choice between using market signals and administrative actions to maintain the balance between supply and demand when the market is tight. Reliance on administrative actions means that there is no clear, price based signal that the system requires the use of emergency resources. In the short run, prices that reflect the shortage of resources signal the need for resources and may result in immediate responses on the supply and demand sides. In the long run, prices provide signals regarding the need for additional generation, demand-response and transmission resources in the scarcity regions.

This suggests that the definition of scarcity should include several stages of scarcity, each with an associated administrative price, rather than the single step now in the Tariff.

PJM should also consider adding new scarcity pricing regions. There would have been six hours of scarcity under PJM rules if BGE and Pepco had been defined to be a Scarcity Region. The PJM Tariff requires PJM to review the defined scarcity pricing regions and file changes (additions or deletions) to them with the Commission, as required.[88]

88 See PJM. "Open Access Transmission Tariff (OATT)," Sixth Revised Volume No. 1, Third Revised Sheet No. 402A.03 (Effective January 27, 2006).

BGE and Pepco are two contiguous transmission zones containing generator buses with 5 percent, or greater, positive distribution factor relative to 500 kV, or greater, transmission constraints, including Bedington — Black Oak. If BGE and Pepco had been defined as a separate scarcity pricing region relative to Bedington-Black Oak and the Conastone Transformer, PJM's loading of maximum emergency generation in BGE and Pepco, to support the Bedington — Black Oak and the Conastone Transformer constraints, would have triggered a scarcity pricing event starting as early as 1233 and ending at 1812 on August 8, 2007.

The current administrative scarcity pricing rules result in a nonlocational signal within the scarcity pricing regions. 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. This provides a signal that is inconsistent with economic dispatch and inconsistent with locational pricing. Nodal scarcity price signals, based on unit specific scarcity offers in the region, would permit individual generators to make decisions about their offers and would provide signals consistent with economic dispatch and locational pricing during the event.

The MMU recommends that the current scarcity rule, as provided in the PJM Tariff, be reviewed and enhanced to ensure competitive prices by introducing:

- Stages of Scarcity Pricing. Administrative scarcity pricing should include stages, based on system conditions, with progressive impacts on prices. The trigger for each stage could be either a clear measure of the level of available operating reserve or the progressive use of stronger emergency measures. For example, stages of scarcity pricing could be triggered by predefined levels of available operating reserve. For example, stages of scarcity pricing could be triggered by the calling of a maximum emergency generation alert that allows maximum emergency capacity to be counted toward operating reserve requirements, the calling of emergency demand response, the recall of noncapacity-backed exports, the loading of maximum emergency generation, voltage reductions, emergency power purchases and manual load dumps in one or more contiguous transmission zones.

- Locational Price Signals. The single scarcity price signal should be replaced by locational signals. Locational signals could be implemented via scarcity offers submitted by generation owners. Generation owners could make explicit scarcity offers, in addition to their price and cost offers, which would be substituted for a unit's price offer for purposes of dispatch, setting LMP and payment when triggered by stages of scarcity declarations by PJM. This would provide a means to signal scarcity that is consistent with economic dispatch, consistent with locational pricing and consistent with competitive market outcomes. Combined with a more refined set of scarcity triggers, this approach would also encourage participants to offer competitively under normal market conditions and competitively in the context of scarcity conditions.

Operating Reserve

Day-ahead and real-time operating reserve credits are paid to generation owners under specified conditions in order to ensure that units are not required to operate for the PJM system at a loss. Sometimes referred to as uplift or revenue requirement make whole, these payments are intended to be one of the incentives to generation owners to offer their energy to the PJM Energy Market at marginal cost and to operate their units at the direction of PJM dispatchers. These credits are paid by PJM market participants as operating reserve charges.

If a unit is selected to operate in the PJM Day-Ahead Energy Market but the market revenues for the entire day resulting from that operation are insufficient to cover all offer components, including startup and no-load, then day-ahead operating reserve credits ensure that all offer components are covered.[89] If a generator, scheduled to operate in the Real-Time Energy Market, operates as directed by PJM dispatchers but the market revenues for the entire day resulting from that operation are insufficient to cover all offer components, then balancing operating reserve credits ensure that all offer components are covered.

The level of operating reserve credits paid to specific units depends on the level of the unit's energy offer, the unit's operating parameters as well as the decisions of PJM operators. Operating reserve credits result in part from decisions by PJM operators, who follow reliability requirements and market rules, to start units or to keep units operating even when hourly LMP is less than the offer price including energy, startup and no-load offers.

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.

The level of operating reserve credits and corresponding charges increased in 2007 by 42.45 percent compared to 2006. The amount of balancing operating reserve credits paid to synchronous condensing increased by 176.79 percent compared to 2006, 17.49 percent of the total net increase. PJM continues internal processes to review and measure daily operating reserve performance, to analyze issues and resolve them in a timely manner, to make better information more readily available to dispatchers and to emphasize the impact of dispatcher decisions on operating reserve charge levels.

The MMU concluded in 2006 that some modifications to PJM rules governing operating reserve credits to generators would be appropriate. Such modifications should aim to ensure that credits paid to market participants and corresponding charges paid by market participants are consistent with incentives for efficient market outcomes and to eliminate gaming incentives and the ability to exercise market power. Such modifications should address both the level of and the appropriate allocation of operating reserve charges, accounting where appropriate and possible for causal factors including location.

89 Operating reserve credits are also provided for pool-scheduled energy transactions, for generating units operating as condensers not as synchronized reserve, for the cancellation of pool-scheduled resources, for units backed down for reliability reasons, for units performing black start tests and for units providing quick start reserve.

On November 15, 2007, after a lengthy but productive membership process, the PJM Members Committee (MC) approved proposed revisions to Schedule 1 of the PJM Operating Agreement and to the operating reserve business rules to enhance the efficiency of the operating reserve process. PJM is expected to file the proposed changes with the FERC in 2008.

The revisions include the following changes to the operating reserve business rules:

- Segmented Make-Whole Payments. Resources will be made whole separately for the blocks of hours they operate at PJM direction. There will a maximum of two segments per calendar day, per unit. The first segment will be the greater of the day-ahead schedule or minimum run time (minimum downtime for demand resources); the second segment will be the remainder of the unit run for that calendar day.

- Parameter-Limited Schedule. When a unit needed for operating reserve has local market power as defined by the three pivotal supplier test, units will be required to use operating parameters consistent with competitive offers. These parameters are defined by unit characteristics and included in a schedule.

- Generator Deviations. PJM will use ramp-limited desired MW to determine generator deviations from desired dispatch. Pool-scheduled generators deemed to be "following dispatch" will not be assessed balancing operating reserve deviations.

- Netting Generator Deviations. Generators that deviate from real-time dispatch will be able to offset deviations by using another generator at the same bus. Both generators must be owned or offered by a single PJM market participant and must have identical electrical impacts on the transmission system.

- Regional Rates for Balancing Operating Reserve Charges. Operating reserve charges will be calculated regionally based on the charges accrued due to regional constraints.

- Allocation of Balancing Operating Reserve Charges. PJM will allocate operating reserve credits to real-time deviations from day-ahead schedules or to real-time load share plus export based on the reasons the credits were paid.

Credit and Charge Categories

Operating reserve credits include day-ahead, synchronous condensing and balancing operating reserve categories. Total operating reserve credits paid to PJM participants equal the total operating reserve charges paid by PJM participants. Table 3-47 shows the categories of credits and charges and their relationship.

Table 3-47 Operating reserve credits and charges

Credits	Charges		
Day ahead:			
Day-Ahead Energy Market	Day-ahead demand		
Day-ahead congestion	Decrement bids		
Day-ahead import transactions	Day-ahead export transactions		
Synchronous condensing	Real-time load		
	Real-time export transactions		
Balancing :	Real-time deviations from day-ahead schedules:		
Balancing energy market			
Balancing congestion			
Lost opportunity cost			
Real-time import transactions			
	Day ahead		Real time
		Net deviations	
	Day-ahead decrement bids	Demand	Real-time load
	Day-ahead load		Real-time sales
	Day-ahead sales		Real-time export transactions
	Day-ahead export transactions		
	Day-ahead increment offers	Supply	Real-time purchases
	Day-ahead purchases		Real-time import transactions
	Day-ahead import transactions		
	Day-ahead scheduled generation	Generator	Real-time generation

Day-Ahead Credits and Charges

Day-ahead operating reserve credits consist of Day-Ahead Energy Market, day-ahead congestion and day-ahead import transaction credits.

The day-ahead operating reserve charges that result from paying total day-ahead operating reserve credits are allocated daily to PJM members in proportion to the sum of their cleared day-ahead demand, decrement bids and day-ahead exports. Table 3-49 shows monthly day-ahead operating reserve charges for calendar years 2006 and 2007.

Synchronous Condensing Credits and Charges

Synchronous condensing credits are provided to eligible synchronous condensers for real-time condensing and energy use costs if PJM dispatches them for purposes other than synchronized reserve, post-contingency constraint control or reactive services.[90]

The operating reserve charges that result from paying operating reserve credits for synchronous condensing are allocated daily to PJM members in proportion to the sum of their real-time load and real-time export transactions. Table 3-49 shows monthly synchronous condensing charges for calendar years 2006 and 2007.

Balancing Credits and Charges

Balancing operating reserve credits consist of balancing energy market credits, balancing congestion credits, lost opportunity cost credits and real-time import transaction credits.[91] Balancing operating reserve credits are paid to generation resources that operate at PJM's request if market revenues are less than the resource's offer. Lost opportunity cost credits are paid to generation resources when their output is reduced by PJM for reliability purposes from their economic or self-scheduled output level. Balancing operating reserve credits are paid to real-time import transactions, if market revenues are less than the offer. Balancing operating reserve credits are also paid to canceled, pool-scheduled resources, to resources providing quick start reserve and to resources performing annual, scheduled black start tests.

The operating reserve charges that result from paying balancing operating reserve credits are allocated daily to PJM members in proportion to their real-time hourly deviations from cleared quantities in the Day-Ahead Market. Table 3-49 shows monthly balancing operating reserve charges for calendar years 2006 and 2007. These deviations fall into three categories and are calculated on an hourly net basis: demand, supply and generator deviations. Each type of deviation is calculated separately and a PJM member may have deviations in all three categories.

- Demand. Hourly deviations in the demand category equal the absolute value of the difference between: a) the sum of cleared decrement bids plus cleared, day-ahead load plus day-ahead exports scheduled

90 PJM. "Manual 28: Operating Agreement Accounting," Revision 39 (January 1, 2008).

91 PJM settlements do not differentiate balancing congestion credits and balancing energy market credits. Balancing congestion credits are defined here as operating reserve credits paid to units that were operated for a transmission constraint in the Real-Time Market or selected for a transmission constraint in the Day-Ahead Market. Balancing energy market credits are what remain in the balancing operating reserve credit category after accounting for credits for balancing congestion, real-time transactions and lost opportunity cost.

through the Enhanced Energy Scheduler (EES);[92] and b) the sum of real-time load plus real-time sales scheduled through eSchedules[93] plus real-time exports scheduled through the EES.

- Supply. Hourly deviations in the supply category equal the absolute value of the difference between: a) the sum of the cleared increment offers plus day-ahead imports scheduled through EES; and b) the sum of the real-time bilateral transactions scheduled through eSchedules plus real-time imports scheduled through EES.

- Generator. Hourly deviations in the generator category equal the absolute value of the difference between: a) a unit's cleared, day-ahead generation; and b) a unit's hourly, integrated real-time generation. More specifically, a unit has calculated deviations for an hour if the hourly integrated real-time output is not within 5 percent of the hourly day-ahead schedule; the hourly integrated real-time output is not within 10 percent of the hourly integrated desired output; or the unit is not eligible to set LMP for at least one five-minute interval during an hour.

Credit and Charge Results

Overall Results

Table 3-48 shows total operating reserve credits from 1999 through 2007, a period when significant market changes occurred.[94, 95] Total operating reserve credits increased by 42.45 percent in 2007.

Table 3-48 also shows the ratio of total operating reserve credits to the total value of PJM billings.[96] In 2007 this ratio did not change from the 1.5 percent of 2006. Over the last eight years, this ratio ranged from a low of 1.5 percent in 2006 and 2007 to a high of 9.6 percent in 2000.

Table 3-48 Total day-ahead and balancing operating reserve charges: Calendar years 1999 to 2007

	Total Operating Reserve Credits	Annual Credit Change	Operating Reserve as a Percent of Total PJM 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	62.05%	9.6%	$0.341	NA	$0.535	NA
2001	$290,867,269	34.05%	8.7%	$0.275	(19.5%)	$1.070	100.2%
2002	$237,102,574	(18.48%)	5.0%	$0.164	(40.4%)	$0.787	(26.4%)
2003	$289,510,257	22.10%	4.2%	$0.226	38.2%	$1.197	52.0%
2004	$414,891,790	43.31%	4.8%	$0.230	1.7%	$1.236	3.3%
2005	$682,781,889	64.57%	3.0%	$0.076	(66.9%)	$2.758	123.1%
2006	$322,315,152	(52.79%)	1.5%	$0.078	2.6%	$1.331	(51.7%)
2007	$459,124,502	42.45%	1.5%	$0.057	(27.0%)	$2.331	75.1%

92 The Enhanced Energy Scheduler is a PJM application used by participants to schedule import and export transactions.

93 PJM's eSchedules is an application used by participants for internal bilateral transactions.

94 Table 3-48 includes all categories of credits as defined in Table 3-47 and includes all PJM settlements' billing adjustments.

95 An Energy Market that clears based on market-based generator offers was initiated on April 1, 1999. The 1999 total includes Energy Market operating reserve credits for three months based on generators' cost-based offers and for nine months based on generators' market-based offers. The Day-Ahead Energy Market opened on June 1, 2000. Operating reserve credits for 1999 and the first five months of 2000 include only those credits paid in the balancing energy market. Since June 1, 2000, operating reserve credits have included credits for both day-ahead and balancing services.

96 See the *2007 State of the Market Report*, Volume II, Section 7, "Congestion," at Table 7-1, "Total annual PJM congestion (Dollars (Millions)): Calendar years 2002 to 2007," for a description of the value of total annual PJM billings during the period indicated.

Finally, Table 3-48 shows the total operating reserve credits per MWh for each full year since the introduction of the Day-Ahead Energy Market.[97] The day-ahead operating reserve rate decreased $0.021 per MWh or 27.0 percent from $0.078 per MWh in 2006 to $0.057 per MWh in 2007. The balancing operating reserve rate increased $1.00 per MWh, or 75.1 percent, from $1.331 per MWh in 2006 to $2.331 per MWh in 2007.

Table 3-49 compares monthly operating reserve charges by category for calendar years 2006 and 2007. While total operating reserve charges increased, the level of day-ahead operating reserve charges decreased by 22.38 percent between 2006 and 2007 and their share of total operating reserve charges decreased from 20.31 percent to 10.98 percent. Synchronous condensing operating reserve credits increased by 176.79 percent between 2006 and 2007.[98] Balancing operating reserve charges increased by 53.69 percent between 2006 and 2007 and their share of total operating reserve charges increased from 75.36 percent to 80.67 percent.

Table 3-49 Monthly operating reserve charges: Calendar years 2006 and 2007

	2006			2007		
	Day Ahead	Synchronous Condensing	Balancing	Day Ahead	Synchronous Condensing	Balancing
Jan	$7,145,655	$511,823	$16,216,936	$5,627,466	$2,001,215	$18,524,772
Feb	$4,525,771	$241,598	$14,107,994	$5,739,401	$2,670,396	$34,259,749
Mar	$4,924,985	$346,133	$7,992,131	$4,611,047	$1,300,459	$23,317,961
Apr	$5,368,796	$156,352	$7,575,039	$5,981,246	$1,208,114	$17,472,454
May	$6,129,196	$492,418	$11,837,289	$6,305,138	$1,584,887	$16,198,291
Jun	$4,383,153	$983,353	$18,003,134	$3,905,778	$2,706,483	$32,779,988
Jul	$4,838,992	$2,073,350	$43,756,738	$2,221,518	$4,374,349	$31,682,112
Aug	$5,045,827	$2,364,265	$49,491,691	$1,909,243	$7,495,702	$61,410,545
Sep	$6,765,877	$938,744	$14,273,544	$2,896,590	$5,046,901	$42,197,260
Oct	$5,244,729	$1,654,702	$12,890,522	$1,970,822	$5,024,503	$29,581,616
Nov	$4,191,905	$882,426	$16,465,964	$3,715,092	$3,332,124	$21,265,389
Dec	$4,929,665	$2,890,772	$23,017,897	$4,404,038	$721,130	$33,454,922
Total	$63,494,551	$13,535,936	$235,628,879	$49,287,379	$37,466,264	$362,145,059
Share of annual charges	20.31%	4.33%	75.36%	10.98%	8.35%	80.67%

Deviations

Real-time deviations from day-ahead schedules are used to allocate balancing operating reserve charges and are the denominator in the balancing operating reserve rate calculation. Table 3-50 shows monthly real-time deviations for demand, supply and generator categories for 2006 and 2007. Total deviations in the

97 In Table 3-48, "Total day-ahead and balancing operating reserve charges: Calendar years 1999 to 2007," numbers are based on PJM market settlements' data that include manual adjustments. The data in Table 3-49, Table 3-51, Table 3-55 and Figure 3-16 are based on the PJM market settlements' database and do not include manual adjustments.

98 Operating reserve credits to synchronous condensing increased because of the more frequent commitment of synchronous condensers for managing congestion in New Jersey. PJM operations shifted the assignment of these synchronous condensers from operating reserve to the Synchronized Reserve Market. See the *2007 State of the Market Report*, Volume II, Section 6, "Ancillary Service Markets."

demand and generator categories were lower in 2007 than in 2006 while total deviations in the supply category were higher in 2007. From 2006 to 2007, the share of total deviations in the demand category decreased by 4.01 percentage points, in the supply category rose by 3.58 percentage points and in the generator category increased by 0.42 percentage points.

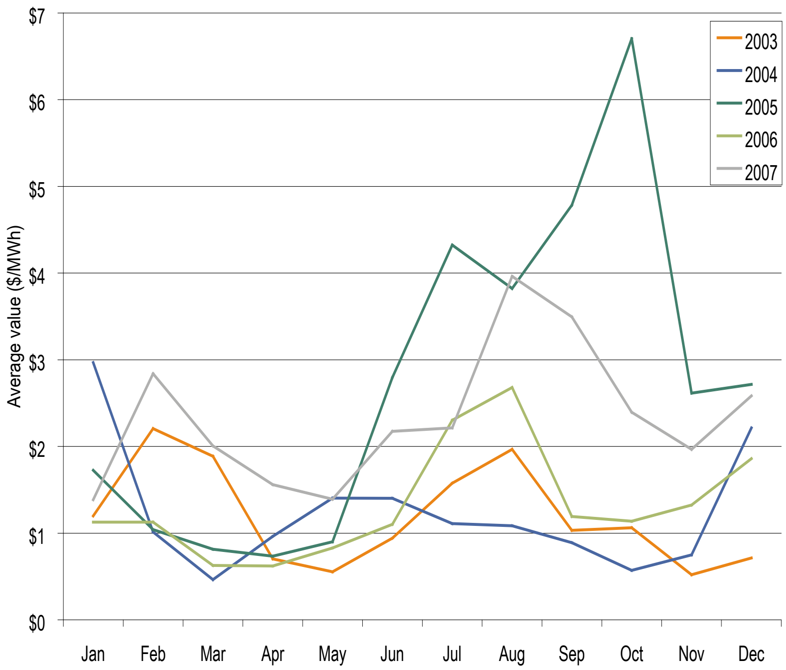
Table 3-50 Monthly balancing operating reserve deviations (MWh): Calendar years 2006 and 2007

	2006 Deviations			2007 Deviations		
	Demand (MWh)	Supply (MWh)	Generator (MWh)	Demand (MWh)	Supply (MWh)	Generator (MWh)
Jan	8,079,917	3,042,526	3,104,765	7,514,621	2,906,334	2,340,412
Feb	7,407,652	2,376,136	2,785,690	6,233,800	2,962,485	2,243,011
Mar	7,782,094	2,440,601	2,579,638	6,358,269	2,550,649	2,376,102
Apr	7,380,697	2,092,666	2,676,689	6,234,452	2,491,365	2,309,824
May	7,732,120	2,476,951	2,700,348	5,835,288	2,701,154	2,574,414
Jun	9,292,155	2,621,207	3,260,040	7,893,872	3,928,908	2,570,994
Jul	11,166,560	3,799,713	3,241,283	7,976,794	3,369,275	2,646,549
Aug	10,639,107	3,321,580	2,879,367	8,302,998	3,262,800	3,301,138
Sep	7,589,892	2,180,845	2,212,283	6,743,208	2,400,749	2,189,309
Oct	6,525,296	2,653,620	2,035,454	6,418,244	2,631,321	2,352,370
Nov	7,228,329	2,685,786	2,379,014	6,249,638	2,407,343	2,156,888
Dec	6,964,809	2,550,484	2,403,937	7,018,333	2,896,010	2,805,085
Total	97,788,628	32,242,115	32,258,508	82,779,517	34,508,392	29,866,097
Share of annual deviations	60.26%	19.87%	19.88%	56.25%	23.45%	20.30%

Balancing Operating Reserve Rate

The balancing operating reserve rate equals the total daily amount of balancing operating reserve credits divided by total daily deviations. It is calculated daily. Figure 3-15 shows monthly average balancing operating reserve rates for the past five years. A large increase in the monthly average balancing operating reserve rate occurred between June and October 2005. In 2007, the monthly average balancing operating reserve rate increased to an average of $2.33 per MW, which was higher than 2006 by $1 per MW.

Figure 3-15 Monthly average balancing operating reserve rate: Calendar years 2003 to 2007



Characteristics of Credits and Charges

Types of Units

Table 3-51 shows the proportion of total PJM installed capacity by unit type that received balancing operating reserve payments, the proportion of total MW capacity that received balancing operating reserve by unit type and the proportion of balancing operating reserve credits received by unit type.[99] In 2007, combustion turbine (CT) units received 59.49 percent of balancing operating reserve credits although they represented 21.31 percent of the capacity that received such credits and CTs that received balancing operating reserve credits represented 15.97 percent of total, PJM installed capacity. Steam units received 19.40 percent of balancing operating reserve credits, but represented 62.02 percent of the capacity that received such credits and steam units that received balancing operating reserve credits represented 46.47 percent of total PJM 2007 installed capacity. In 2007, units that received balancing operating reserve credits represented 74.93 percent of total installed PJM capacity.[100] In 2006, units that received balancing operating reserve credits had represented 78.62 percent of total installed PJM capacity.

99 In Table 3-51 balancing operating reserve credits include balancing congestion, balancing energy and lost opportunity cost credits. This table reflects a settlement adjustment for a hydroelectric unit.

100 The value of total PJM installed capacity used for these calculations was based on the amount recorded on June 1, 2007.

Table 3-51 Installed capacity percentage (By unit type receiving operating reserve payments): Calendar year 2007

Unit Type Receiving Operating Reserve Credits	Share of Total PJM Installed Capacity	Share of Capacity Receiving Operating Reserve Credits	Share of Balancing Operating Reserve Credits
Combined cycle	12.31%	16.43%	18.30%
Combustion turbine	15.97%	21.31%	59.49%
Diesel	0.19%	0.25%	2.81%
Hydroelectric	0.00%	0.00%	0.00%
Nuclear	0.00%	0.00%	0.00%
Steam	46.47%	62.02%	19.40%
Total	74.93%	100.00%	100.00%

Economic and Noneconomic Generation

Economic generation includes units producing energy at an offer price less than, or equal, to LMP. Noneconomic generation includes units that are producing energy but at a higher offer price than the LMP. Noneconomic generation includes units assigned by PJM to run and units not assigned by PJM to run or to provide regulation. Regulation generation includes units assigned by PJM to provide regulation. The level of noneconomic generation is an indicator of the level of generation that may require operating reserve credits. However, the data are hourly and some generation that is noneconomic for an hour may receive adequate market revenues during other hours to offset any shortfall.[101]

Table 3-52 shows the percentage of total PJM self-scheduled generation, economic generation, noneconomic generation and regulation generation for 2007.

Table 3-52 PJM self-scheduled, economic, noneconomic and regulation generation receiving operating reserve payments: Calendar year 2007

	All Hours	On Peak	Off Peak
Self-scheduled generation	46.13%	44.99%	48.84%
Economic generation	47.59%	50.92%	39.72%
Noneconomic generation	4.98%	3.59%	8.26%
Regulation generation	1.30%	0.50%	3.18%
Total	100.00%	100.00%	100.00%

101 Self-scheduled units were not included in either economic or noneconomic categories. Self-scheduled units are those units which indicate to PJM that they are self-scheduled. Units which are operating, but are not assigned by PJM to run and are not self-scheduled, are noneconomic.

Table 3-53 presents the share of self-scheduled, economic, noneconomic and regulation generation for each unit type. For example, in 2007 steam units represented 92.65 percent of all economic generation. Table 3-54 presents the share of each unit type for self-scheduled, economic, noneconomic and regulation generation. For example, in 2007 48.34 percent of steam unit generation was economic.

Table 3-53 PJM generation by unit type receiving operating reserve payments: Calendar year 2007

	Self-Scheduled Generation	Economic Generation	Noneconomic Generation	Regulation Generation
Combined cycle	3.66%	5.64%	24.11%	8.54%
Combustion turbine	0.34%	0.89%	8.90%	1.40%
Diesel	0.17%	0.02%	0.12%	0.00%
Hydroelectric	2.97%	0.80%	0.00%	0.00%
Steam	92.65%	92.65%	66.87%	90.05%
Wind	0.22%	0.00%	0.00%	0.00%
Total	100.00%	100.00%	100.00%	100.00%

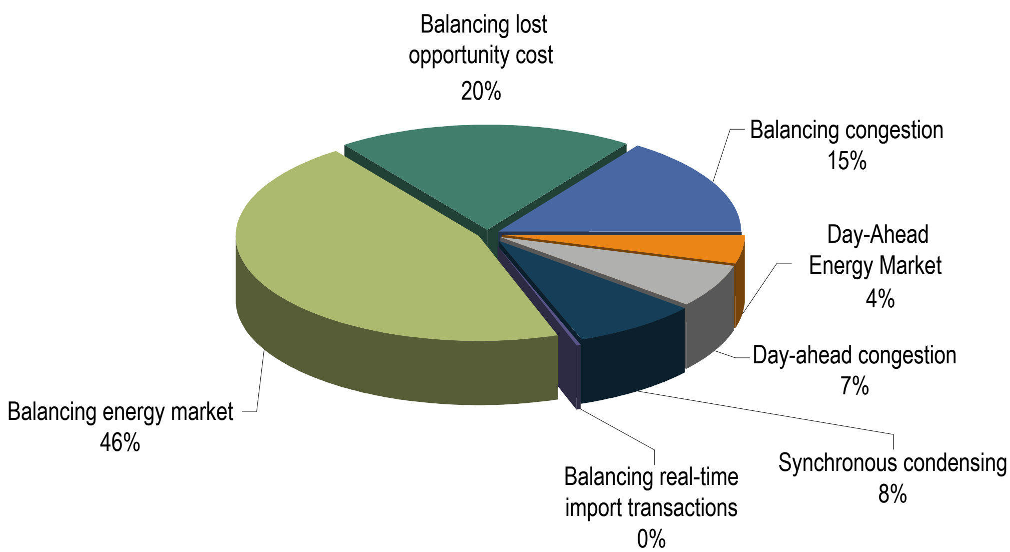
Table 3-54 PJM unit type generation distribution (By unit type receiving operating reserve payments): Calendar year 2007

	Self-Scheduled Generation	Economic Generation	Noneconomic Generation	Regulation Generation	Total
Combined cycle	29.63%	47.29%	21.13%	1.95%	100.00%
Combustion turbine	14.97%	40.68%	42.59%	1.75%	100.00%
Diesel	84.64%	8.64%	6.72%	0.00%	100.00%
Hydroelectric	78.24%	21.76%	0.00%	0.00%	100.00%
Steam	46.73%	48.34%	3.65%	1.28%	100.00%
Wind	99.39%	0.61%	0.00%	0.00%	100.00%

Operating Reserve Credits by Category

Figure 3-16 shows that the largest share of total operating reserve credits, 45.23 percent, was paid to resources in the balancing energy market during 2007 and that 80.68 percent of total operating reserve credits was in the balancing category. Figure 3-16 also shows that 4.21 percent of total operating reserve credits was paid to resources in the Day-Ahead Energy Market and that 10.98 percent of total operating reserve credits was in the day-ahead category.[102]

Figure 3-16 Operating reserve credits: Calendar year 2007



Geography of Balancing Credits and Charges

Table 3-55 compares the share of balancing operating reserve charges paid by and credits paid to generators located within the Mid-Atlantic Region to the share of charges paid by and credits paid to generators located within all other PJM control zones.[103] The other control zones include those in the Western Region (i.e., the AEP, AP, ComEd, DAY and DLCO control zones) and in the Southern Region (i.e., the Dominion Control Zone). On average, 46.97 percent of all generator charges were paid by generators in the Mid-Atlantic Region. On average, 61.72 percent of energy credits, 84.78 percent of congestion credits and 20.61 percent of lost opportunity cost credits were paid to generators in the Mid-Atlantic Region. Table 3-55 also shows generator credits and charges as shares of total operating reserve credits and charges. On average, generator charges were 16.40 percent of all operating reserve charges and generator credits were 78.81 percent of all operating reserve credits.

These results do not necessarily mean that there is an inappropriate regional allocation of operating reserve charges but reflect the usage of actual resources to meet the need for system operating reserve.

102 There were no day-ahead import transactions in 2007 that received operating reserve credits.

103 Balancing operating reserve charges in Table 3-55 include only those in the generator category. Balancing operating reserve credits in Table 3-55 include balancing energy market credits, balancing congestion credits and lost opportunity cost credits. Categories are defined in Table 3-47.

Table 3-55 Monthly balancing operating reserve charges and credits to generators (By location): Calendar year 2007

	Mid-Atlantic Region				Other Control Zones					
	Generation Charge	Energy Credit	Congestion Credit	Lost Opportunity Cost	Generation Charge	Energy Credit	Congestion Credit	Lost Opportunity Cost	Generation Charges Share of Total Operating Reserve Charges	Generation Credits Share of Total Operating Credits
Jan	46.53%	64.05%	93.74%	20.33%	53.47%	35.95%	6.26%	79.67%	14.11%	70.83%
Feb	43.98%	58.83%	93.05%	12.67%	56.02%	41.17%	6.95%	87.33%	16.56%	80.19%
Mar	54.05%	59.26%	65.97%	26.59%	45.95%	40.74%	34.03%	73.41%	16.92%	79.78%
Apr	52.16%	52.95%	85.45%	16.11%	47.84%	47.05%	14.55%	83.89%	15.19%	70.85%
May	49.31%	38.26%	87.96%	38.36%	50.69%	61.74%	12.04%	61.64%	15.67%	67.16%
Jun	41.37%	62.70%	69.77%	18.97%	58.63%	37.30%	30.23%	81.03%	16.02%	83.21%
Jul	47.61%	67.52%	71.67%	18.80%	52.39%	32.48%	28.33%	81.20%	15.89%	82.77%
Aug	45.01%	69.90%	85.37%	20.53%	54.99%	30.10%	14.63%	79.47%	20.03%	86.72%
Sep	43.25%	63.01%	73.28%	11.60%	56.75%	36.99%	26.72%	88.40%	16.03%	84.16%
Oct	51.64%	61.84%	94.22%	12.40%	48.36%	38.16%	5.78%	87.60%	16.84%	80.88%
Nov	48.36%	71.92%	97.42%	22.52%	51.64%	28.08%	2.58%	77.48%	14.19%	73.95%
Dec	40.43%	70.38%	99.48%	28.44%	59.57%	29.62%	0.52%	71.56%	19.30%	85.22%
Average	46.97%	61.72%	84.78%	20.61%	53.03%	38.28%	15.22%	79.39%	16.40%	78.81%

Market Power Issues

The exercise of market power by units that are paid operating reserve credits is also a contributor to the level of operating reserve charges paid by PJM members. Market power issues are first examined by analyzing the characteristics of the top 10 units receiving operating reserve credits. The top 10 units are relevant, not because these are the only units with the ability to exercise market power, but because operating reserve credits have been so highly concentrated in payments to these units over the last several years. The market power analysis includes a calculation of the impact on total operating reserve credits of payments to generators associated with markups of price over cost in excess of the competitive level. Unit operating parameters also play a role in the level of operating reserve credits paid to units. The submission of inflexible operating parameters, including artificially long minimum run times, arbitrarily small numbers of starts, daily and hourly economic minimum and economic maximum points that are arbitrarily close or equal, contribute to higher levels of operating reserve credits.

A complete resolution of the market power issue in the payment of operating reserve credits must provide to PJM operators better tools for defining and making optimal economic choices and must define the relevant market, must determine when the market is structurally noncompetitive and must apply mitigation in such situations. In addition, the exemption of units from local market power mitigation rules should be terminated if they exercise market power which is reflected in operating reserve credits rather than directly in LMP.

PJM's anticipated filing of changes to the operating reserve rules, if accepted by the FERC, will address the issues related to operating parameters when PJM also makes appropriate modifications to the way in which it defines markets for operating reserve.

Top 10 Units

A disproportionate share of balancing and day-ahead operating reserve credits has been paid to a small number of units and companies since 2001. This continued to be the case in 2007. As Table 3-56 shows, the top 10 units, less than 1 percent of all units, received 29.75 percent of total operating reserve credits in 2007, a small increase over the 29.72 percent in 2006. The top 20 units received 39.8 percent of operating reserve credits in 2007 and 36.9 percent in 2006. In 2007 five companies owned the top 10 units. In 2006, the top 10 units were owned by four companies. In 2006, the top generation owner received 16 percent of the total operating reserve credits paid, and in 2007, the top generation owner received 8 percent of the total operating reserve credits.

Table 3-56 Top 10 operating reserve revenue units (By percent of total system): Calendar years 2001 to 2007

	Percent	Top 10 Units Percent of Total PJM Units
2001	46.67%	1.81%
2002	32.01%	1.54%
2003	39.28%	1.28%
2004	46.28%	0.90%
2005	27.67%	0.79%
2006	29.72%	0.83%
2007	29.75%	0.84%

Markup

Unit Markup - Top 10 Units

To determine the contribution that unit price offers, in excess of cost, make to operating reserve payments, the MMU performed a markup analysis of the top 10 units.[104] As Table 3-57 shows, the markup for the top 10 units averaged 45.8 percent in 2007, a substantial increase over prior years with the exception of 2005 when the markup for the top 10 units averaged 75.4 percent. The markup for the top 10 units is a weighted-average, whose weights are generator output when operating reserve credits are paid.

The generation owner with the largest share of top 10 credits received 47.82 percent of Energy Market operating reserve credits paid to the top 10 units and had a weighted-average markup of 0 percent in 2007. The next generation owner received 30 percent of Energy Market operating reserve payments made to the top 10 units and had a weighted-average markup of 33.7 percent and the third generation owner received 13 percent of Energy Market operating reserve payments made to the top 10 units and had a weighted-average markup of 126.5 percent in 2007. In 2006 the top owner received 69 percent of Energy Market operating reserve payments made to the top 10 units and had a weighted-average markup of 0 percent.

104 Markup is calculated as [(Price – Cost)/Cost] where cost represents the cost-based offer as defined in PJM “Manual 15: Cost Development Guidelines,” Revision 7 (August 3, 2006). As a result, the markups here are not directly comparable to those calculated as [(Price – Cost)/Price].

For each year 2001 to 2006, the top 10 units receiving operating reserve credits were either combined-cycle (CC) technology or conventional steam generation. In 2007, one unit out of the top 10 units receiving operating reserve credits was CT technology, while the rest remained CC technology or conventional steam generation. The CT unit accounted for the smallest share of the operating reserve credits received by the top 10 units in 2007, representing 4.2 percent of the credits. Steam units represented 18.2 percent of the credits received by the top 10 in 2007. CC units accounted for a larger share of the operating reserve credits received by the top 10 units in 2007, representing 77.6 percent of the credits received by the top 10 in 2007, as shown in Table 3-57.

Table 3-57 Top 10 operating reserve revenue units' markup: Calendar years 2001 to 2007

	Top Units' Markup	Steam Percent of Top 10	Steam Markup	Combined Cycle Percent of Top 10	Combined Cycle Markup	Combustion Turbine Percent of Top 10	Combustion Turbine Markup
2001	2.9%	60.2%	2.2%	39.8%	7.4%	0.0%	0.0%
2002	11.3%	54.4%	8.0%	45.6%	20.4%	0.0%	0.0%
2003	16.9%	50.1%	19.4%	49.9%	11.3%	0.0%	0.0%
2004	3.0%	12.2%	0.1%	87.8%	4.9%	0.0%	0.0%
2005	75.4%	20.3%	52.9%	79.7%	81.7%	0.0%	0.0%
2006	20.9%	9.6%	1.8%	90.4%	24.5%	0.0%	0.0%
2007	45.8%	18.2%	28.8%	77.6%	47.1%	4.2%	56.6%

Unit Markup - All Units

PJM's offer-capping rules provide that specific units are exempt from offer capping, based on their date of construction. Five of the top 10 units are exempt from offer capping for local market power.[105] Table 3-58 shows the simple average markup for generators exempt from offer capping, for generators not exempt from offer capping and for all generators, when balancing operating reserve credits were paid.[106] For all units, when operating reserve credits were paid, the markup for exempt units was almost three times higher than the markup for non-exempt units, 19 percent for exempt units and 7 percent for non-exempt units. The associated maximum markups exceeded the average levels by a substantial amount; the maximum markup for an exempt unit was in excess of 700 percent.[107]

Table 3-58 Simple average generator markup: Calendar year 2007

Unit Class	Exempt	Non-Exempt	All Units
All units	19%	7%	8%
CC	28%	(10%)	1%
CT	14%	11%	11%
Diesel	14%	6%	7%
Steam	NA	0%	0%

105 See the *2007 State of the Market Report*, Volume II, Section 2, "Energy Market, Part 1," at "Exempt Unit Markup."

106 The weighted-average markup calculations are weighted by real-time generation.

107 For calendar year 2006 this percentage was in excess of 1,300 percent. There was an error in the *2006 State of the Market Report*, which showed 130 percent.

Impact of Markup by Exempt Units

Table 3-59 compares the total balancing operating reserve rate and the balancing operating reserve rate adjusted to remove all markups above 10 percent for exempt units.[108] This comparison shows the impact on operating reserve charges of markups over cost by units exempt from offer-capping rules. The impact is the result of increased markups by the 43 exempt units that received balancing operating reserve credits in 2007.[109] If the exempt units had been subject to offer-capping rules at the times they were paid operating reserve credits, the cumulative current total balancing operating reserve credit in 2007 would have been lower by about $35 million and the balancing operating reserve rate in 2007 would have been 9.85 percent lower.

Table 3-59 Balancing operating reserve rate for exempt units (Actual and markup-adjusted): Calendar year 2007

	Current Rate	Markup-Adjusted Rate
Jan	1.38	1.29
Feb	2.84	2.48
Mar	2.01	1.79
Apr	1.56	1.41
May	1.39	1.34
Jun	2.18	2.01
Jul	2.21	2.04
Aug	3.96	3.60
Sep	3.49	3.09
Oct	2.40	2.16
Nov	1.97	1.73
Dec	2.58	2.27
Annual average	2.33	2.10

108 The MMU estimates the costs for exempt units because such units are not required to submit cost-based offers to PJM. All markup results for exempt units are based on the MMU cost estimates.

109 These are the units that received balancing energy and balancing congestion credits.

Unit Operating Parameters

Operating reserve credits also result from the submission of artificially restrictive, unit-specific operating parameters. For example, if a unit is needed by PJM for reliability purposes and if that unit, with a price offer equal to its cost offer, has only one permitted start per day although it is capable of three, has a 24-hour minimum run time although its actual minimum run time is four hours and a two-hour start time although its actual start time is 30 minutes, then it receives higher operating reserve payments than if those operating parameters were not in place. Once a unit is turned on for PJM for reliability reasons, operating reserve rules require that PJM pay the unit the difference between market revenues and its offer, including its offered operating parameters. Thus, PJM members have to pay this unit its offer price for 24 hours although if the unit had offered its actual capability to PJM, payments would have been made for only four hours. If a unit sets its economic minimum output level at, or close to, its economic maximum output level, although the actual minimum and maximum output levels have a significant differential, PJM members have to pay the unit its offer price for its offered economic minimum. If the unit had offered its actual economic minimum to PJM, PJM could have reduced the unit's output to that minimum when LMP fell below its offer price, thus reducing operating reserve credits and charges. Restrictive operating parameters can also interact with unit-specific markups to increase operating reserve payments to units.

This issue will be addressed if PJM's proposed modifications to the operating reserve rules are accepted by the FERC.

SECTION 4 – 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. The external regions include both market and non market control areas.[1]

Overview

Interchange Transaction Activity

- Aggregate Imports and Exports in the Real-Time Market. During 2007, PJM was a net exporter of energy in the Real-Time Market. In the Real-Time Market, monthly net interchange averaged -1,189 GWh.[2] Gross monthly import volumes averaged 2,500 GWh while gross monthly exports averaged 3,689 GWh.

- Transactions in the Day-Ahead Energy Market. While PJM market participants historically imported and exported energy primarily in the Real-Time Energy Market, that is no longer the case. In 2007, gross imports in the Day-Ahead Energy Market were 85 percent of the Real-Time Market's gross imports (77 percent in 2006) while gross exports in the Day-Ahead Market were 103 percent of the Real-Time Market's gross exports (86 percent in 2006) and net interchange in the Day-Ahead Energy Market exceeded net interchange in the Real-Time Energy Market by 39 percent. In the Day-Ahead Market, monthly net interchange averaged -1,657 GWh. Gross monthly import volumes averaged 2,135 GWh while gross monthly exports averaged 3,792 GWh.

- Interface Imports and Exports in the Real-Time Market. In the Real-Time Market in 2007, there were net exports at 18 of PJM's 23 interfaces. The top three net exporting interfaces in the Real-Time Market accounted for 42 percent of the total net exports: PJM/Tennessee Valley Authority (TVA) with 19 percent, PJM/MidAmerican Energy Company (MEC) with 12 percent and PJM/Neptune (NEPT) with 11 percent of the net export volume. Five PJM interfaces had net imports, with two importing interfaces accounting for 95 percent of net import volume: PJM/Ohio Valley Electric Corporation (OVEC) with 74 percent and PJM/Duke Energy Corp. (DUK) with 21 percent.

- Interface Imports and Exports in the Day-Ahead Market. In the Day-Ahead Market, there were net exports at 16 of PJM's 23 interfaces. The top three net exporting interfaces accounted for 54 percent of the total net exports, PJM/Northern Indiana Public Service Company (PJM/NIPS) with 27 percent, PJM/western Alliant Energy Corporation (ALTW) with 16 percent and PJM/MEC with 11 percent. There were net imports in the Day-Ahead Market at six of PJM's 23 interfaces. The top three importing interfaces accounted for 98 percent of the total net imports, PJM/OVEC with 72 percent, PJM/New York Independent System Operator Interface (NYIS) and PJM/DUK each with 13 percent.

1 As part of this analysis of transactions, the Market Monitoring Unit (MMU) compared the market results in 2007 to those of 2006 and certain other prior years. During calendar years 2004 and 2005, PJM conducted the phased integration of five control zones: ComEd, American Electric Power (AEP), The Dayton Power & Light Company (DAY), Duquesne Light Company (DLCO) and Dominion. By convention, control zones bear the name of a large utility service provider working within their boundaries. The nomenclature applies to the geographic area, not to any single company. For additional information on PJM's footprint and the definition of these phases, see *2007 State of the Market Report*, Volume II, Appendix A, "PJM Geography."

2 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.

Interchange Transaction Topics

- PJM Interface Pricing with Organized Markets.

  - PJM and Midwest ISO Interface Pricing. During 2007, 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 2007, the relationship between prices at the PJM/NYIS Interface and at the NYISO/PJM proxy bus reflected economic fundamentals as did the relationship between interface price differentials and power flows between PJM and NYISO. Both continued to be affected by differences in institutional and operating practices between PJM and NYISO.

- PJM TLRs. The number of transmission loading relief procedures (TLRs) issued by PJM continued to decline, with 41 percent fewer during 2007 (80) than 2006 (136). The reduction in TLRs declared by PJM is consistent with the fact that market signals, rather than market interventions, are being used more frequently to manage constraints on interarea transactions. However, more needs to be done to assure that market signals rather than TLRs are used to manage constraints affecting interarea transactions. Access to the data required for understanding loop flow would be a positive first step toward economic management of regional constraints.

- Operating Agreements with Bordering Areas.

  - PJM and New York Independent System Operator, Inc. Joint Operating Agreement (JOA).[3] On May 22, 2007, the JOA between PJM and the New York Independent System Operator (NYISO) became effective. This agreement was developed to improve reliability. It also formalizes the process of electronic checkout of schedules, the exchange of interchange schedules to facilitate calculations for available transfer capability (ATC) and standards for interchange revenue metering. This agreement does not include provisions for market-based congestion management or other market-to-market activity. PJM and NYISO should develop market-based congestion management protocols as soon as practicable.

  - PJM and Midwest ISO Joint Operating Agreement. The "Joint Operating Agreement between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C." continued, in 2007 as in 2006, in its second, and final, phase of implementation including market-to-market activity and coordinated, market-based congestion management within and between both markets.[4]

3 See "Joint Operating Agreement Among And Between New York Independent System Operator Inc. And PJM Interconnection, L.L.C." (May 22, 2007) (Accessed January 25, 2008) <http://www.pjm.com/documents/downloads/agreements/20071102-nyiso-pjm.pdf > (208 KB).

4 See "Joint Operating Agreement between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C." (August 24, 2007) (Accessed January 29, 2008) <http://www.pjm.com/documents/downloads/agreements/joa-complete.pdf> (1,662 KB).

- PJM, Midwest ISO and TVA Joint Reliability Coordination Agreement.[5] The Joint Reliability Coordination Agreement (JRCA) executed on April 22, 2005, provides for comprehensive reliability management 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 2007.

- PJM and Progress Energy Carolinas, Inc. Joint Operating Agreement.[6] On September 9, 2005, the United States Federal Energy Regulatory Commission (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 2007.

- PJM and Virginia and Carolinas Area (VACAR) South Reliability Coordination Agreement.[7] On May 23, 2007, PJM and VACAR South (VACAR is a subregion within the NERC Southeastern Electric Reliability Council (SERC) Region) entered into a reliability coordination agreement. It provides for system and outage coordination, emergency procedures and the exchange of data. Provisions are also made for regional studies and recommendations to improve the reliability of interconnected bulk power systems.

- Interface Pricing Agreements with Individual Companies. PJM entered into locational interface pricing agreements with three companies in 2007 that extend the concept of the dynamic scheduling of individual units to entire control areas. These agreements were made available through the PJM website by PJM after a request by the MMU in October. Each of these agreements established a locational price for power sales between PJM and the individual company that applies under specified conditions and that differs from the generally applicable interface price. PJM needs to ensure that such pricing is transparent and that all participants have access to the defined pricing when in the same position.

- Consolidated Edison Company of New York, Inc. (Con Edison) and Public Service Electric and Gas Company (PSE&G) Wheeling Contracts. During 2007, PJM continued to operate under the terms of the operating protocol that had been developed in 2005.[8] All parties also continued to pursue work on the 19 items identified in the work plan to improve protocol performance. In August the FERC denied a rehearing of Con Edison's complaints regarding protocol performance and refunds.[9]

- Neptune Underwater Transmission Line to Long Island, New York. On July 1, 2007, a 65-mile direct current (DC) transmission line from Sayreville, New Jersey, to Nassau County on Long Island, including undersea and underground cable was placed in service. This is a merchant 230 kV transmission line with a capacity of 660 MW. The line is bi-directional, but in 2007, with the exception of testing, power flows were only from PJM to New York. The average hourly flow for the period July through December was -599 MWh.

5 See "Joint Reliability Coordination (JRCA) among the Midwest ISO, PJM and TVA" (April 22, 2005) (Accessed February 4, 2008) <http://www.pjm.com/documents/downloads/agreements/20050422-jrca-final.pdf> (145 KB).

6 See "Joint Operating Agreement (JOA) between Progress Energy Carolinas, Inc. and PJM" (July 29, 2005) (Accessed February 4, 2008) <http://www.pjm.com/documents/ferc/documents/2005/20050729-er05-___-000.pdf> (2.90 MB).

7 See "Adjacent Reliability Coordinator Coordination Agreement" (May 23, 2007) (Accessed February 19, 2008) <http://www.pjm.com/documents/downloads/agreements/executed-pjm-vacar-rc-agreement.pdf > (532 KB).

8 111 FERC ¶ 61,228 (2005).

9 FERC Order Denying Rehearing, Order, Docket No. EL02-23 (August 15, 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 0.5 percent in 2007, greater differences existed at 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 Financial Transmission Right (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 it had in 2006, the PJM/Michigan Electric Coordinated System (MECS) Interface continued to exhibit large imbalances between scheduled and actual power flows, particularly during the overnight hours. The PJM/TVA Interface also exhibited large mismatches between scheduled and actual power flows, although these mismatches have declined since the consolidation of the former PJM southeast and southwest pricing points in October 2006. 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. The improvements in the 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) observed at the end of 2006 continued during 2007. 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.

  - Data Required for Full Loop Flow Analysis. A complete analysis of loop flow across the Eastern Interconnection could enhance overall market efficiency, shed light on the interactions among market and non market areas and permit market-based congestion management across the Eastern Interconnection. 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. 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. PJM is presently working with the North American Electric Reliability Council (NERC) and North American Energy Standards Board (NAESB) to increase transparency of scheduled and actual transactions, generation and loads from other control areas. This effort should be given a high priority.

- Ramp Reservation Rule Change. In 2006 the MMU developed, PJM proposed and the membership agreed to, changes in the ramp reservation rules that imposed limits on the time that a ramp reservation could be held without an associated energy schedule. These rules showed positive results when they were implemented that were sustained through 2007. An additional rule to address artificial ramp creation was added in 2007. This rule sets out the procedure for PJM operators to follow if they observe a participant who has offsetting import and export ramp reservations, but is only scheduling on one of them while letting the other expire. This rule has not yet been incorporated in PJM's software although dispatchers may enforce the rule manually.

- Spot Import Service. A new interchange transaction issue emerged in 2007. Some participants obtain and hold large amounts of spot import service reservations without using the service. Prior to April 2007, PJM did not limit spot import service, preferring to let market prices ration the use of the service which is not physically limited. PJM interpreted its JOA with Midwest ISO to require a limitation on spot import service in order to limit the impact of such transactions on selected external flowgates. The rule caused the availability of spot import service to be limited by ATC on the transmission path. Most of the spot import reservations were for monthly service and most monthly reservations were not used. Following implementation of the rule, participants have complained that they are not able to obtain this service. There are a number of possible options for addressing the issue including making reservations available only hourly or daily or requiring reservation holders to release reservations if they will not be used within a defined lead time.

- Up-to Congestion Transactions. Up-to congestion transactions are Day-Ahead Energy Market transactions for which participants can specify the maximum level of positive congestion cost that they are willing to pay, up to a cap of $25 per MWh. There is a mismatch between up-to congestion transactions in the Day-Ahead Energy Market and the Real-Time Energy Market. In the Day-Ahead Energy Market, an up-to congestion import transaction is submitted and modeled as an injection at the interface and a withdrawal at a specific PJM node. In real time, the power does not flow to the PJM node specified in the day-ahead transaction. This mismatch results in inaccurate pricing and can provide a gaming opportunity.

Conclusion

Transactions between PJM and multiple control areas in the Eastern Interconnection are part of a single energy market. While some of these control areas are termed market areas and some are termed non market areas, all electricity transactions are part of a single energy market. 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 Auction Revenue Rights (ARRs) in PJM) and transparent, least-cost, security-constrained economic dispatch for all available generation. 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 2007 including evolving transaction patterns, economics and issues. While PJM market participants historically imported and exported energy primarily in the Real-Time Energy Market, that is no longer the case. 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 42 percent of the total real-time net exports and two interfaces accounted for 95 percent of the real-time net import volume. Three interfaces accounted for 54 percent of the total day-ahead net exports and three interfaces accounted for 98 percent of the day-ahead net import volume.

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 largely 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. PJM and NYISO should implement market-to-market coordination modeled on the PJM and MISO JOA as soon as possible. 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 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. The reverse can also occur. For interactions with both market and non market areas, the goal should be 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 PJM in 2007. However, more needs to be done to assure that market signals rather than TLRs are used to manage constraints affecting interarea transactions. PJM and NYISO, as neighboring market areas, should develop market-based congestion management protocols as soon as practicable. In addition, PJM should continue its efforts to gain access to the data required to understand loop flows in real time and to ensure that responsible parties pay the costs of redispatch.

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 for specific units 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. PJM also entered into agreements with specific control areas for separate interface pricing that have been questioned with respect to transparency and equal access. PJM needs to ensure that such pricing is transparent and that all participants have access to the defined pricing when in the same position.

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. 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 continue not to be fully understood 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, shed light on the interactions among market and non market areas and permit market-based congestion management across the Eastern Interconnection. 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. PJM and Midwest ISO issued a joint loop flow report in 2007 that made three recommendations including the establishment of an energy schedule tag archive. The archive would capture and retain data for the entire Eastern Interconnection including tag impact, generation-to-load impact and market flow impact data for flowgates in the interchange distribution calculator (IDC). The archive would be a prime source of information needed to perform after-the-fact analyses and reviews. This effort should be given a high priority as the data needs have been well understood for some time.

PJM needs to continue to pay careful attention to all the mechanisms used to manage flows at the interfaces between PJM and surrounding areas. PJM manages its interface with external areas, in part, through limitations on the amount of change in net interchange within 15-minute intervals. The change in net interchange is referred to as ramp. Changes in net interchange affect PJM operations and markets as they require increases or decreases in generation to meet load. As a result of the fact that ramp is free but is a valuable resource, there are strong incentives to game the ramp rules. The same is true of spot import service. Up-to congestion service is a market option used to import power into PJM which can create mismatches between transactions in the Day-Ahead Energy Market and the Real-Time Energy Market that result in inaccurate pricing and can provide a gaming opportunity.

Interchange Transaction Activity

Aggregate Imports and Exports

PJM continues to be a net exporter of power. (See Figure 4-1, Figure 4-2 and Figure 4-3.)[10]

During 2007, PJM was a net exporter of energy in the Real-Time Market for each month except February. Total net interchange of -14,261 GWh was less than net interchange of -18,081 GWh in 2006. The peak month for net interchange was August in 2007, -3,483 GWh; it had been June in 2006, -2,738 GWh. Monthly gross exports averaged 3,689 GWh and monthly gross imports averaged 2,500 GWh, for an average monthly net interchange of -1,189 GWh. In the Day-Ahead Market, PJM was also a net exporter of energy. Total net interchange was -19,885 GWh. The peak month for net interchange was August, -3,472 GWh. Monthly gross exports averaged 3,792 GWh and monthly gross imports averaged 2,135 GWh, for an average monthly net interchange of -1,657 GWh.

While PJM market participants historically imported and exported energy primarily in the Real-Time Energy Market, that is no longer the case. (See Figure 4-2.) Transactions in the Day-Ahead Market create financial obligations to deliver in the Real-Time Market and to pay operating reserve charges based on differences between the transaction MW in the Day-Ahead and Real-Time Energy Markets. In 2007, gross imports in

10 Calculated values shown in Section 4, "Interchange Transactions," are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

the Day-Ahead Energy Market were 85 percent of the Real-Time Market's gross imports (77 percent in 2006) while gross exports in the Day-Ahead Market were 103 percent of the Real-Time Market's gross exports (86 percent in 2006) and net interchange in the Day-Ahead Energy Market exceeded the net interchange in the Real-Time Energy Market by 39 percent.

Figure 4-1 PJM real-time scheduled imports and exports: Calendar year 2007

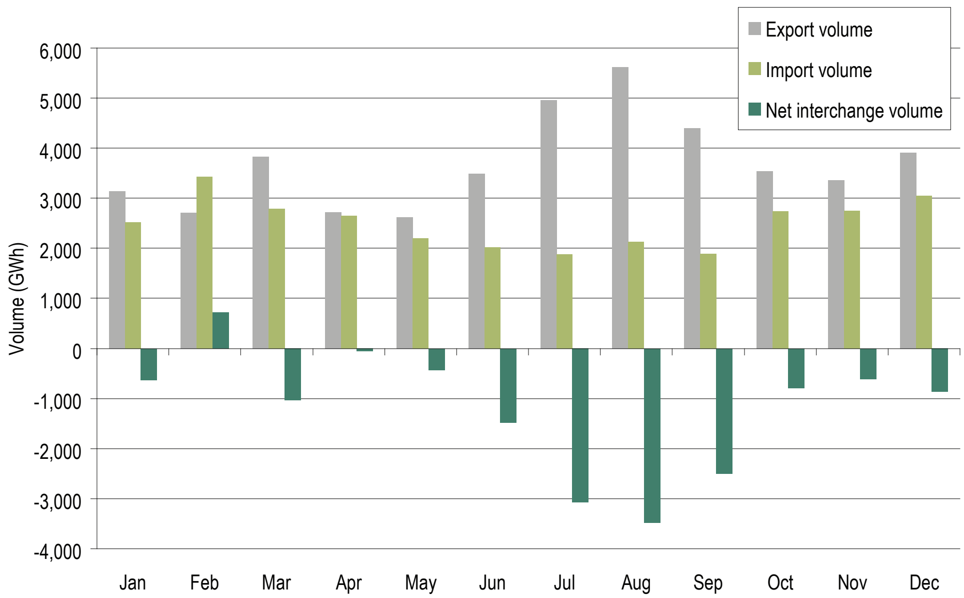


Figure 4-2 PJM day-ahead scheduled imports and exports: Calendar year 2007

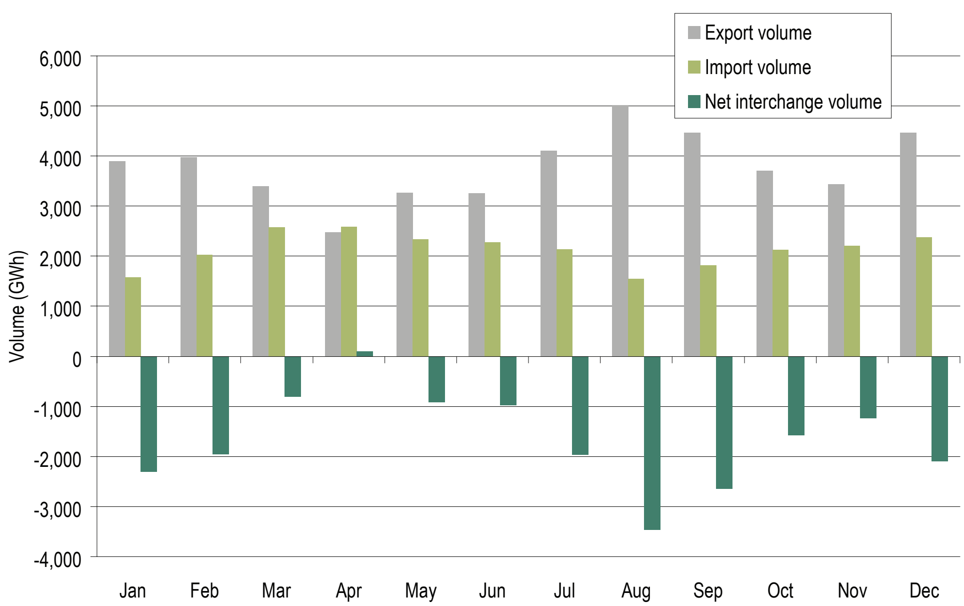
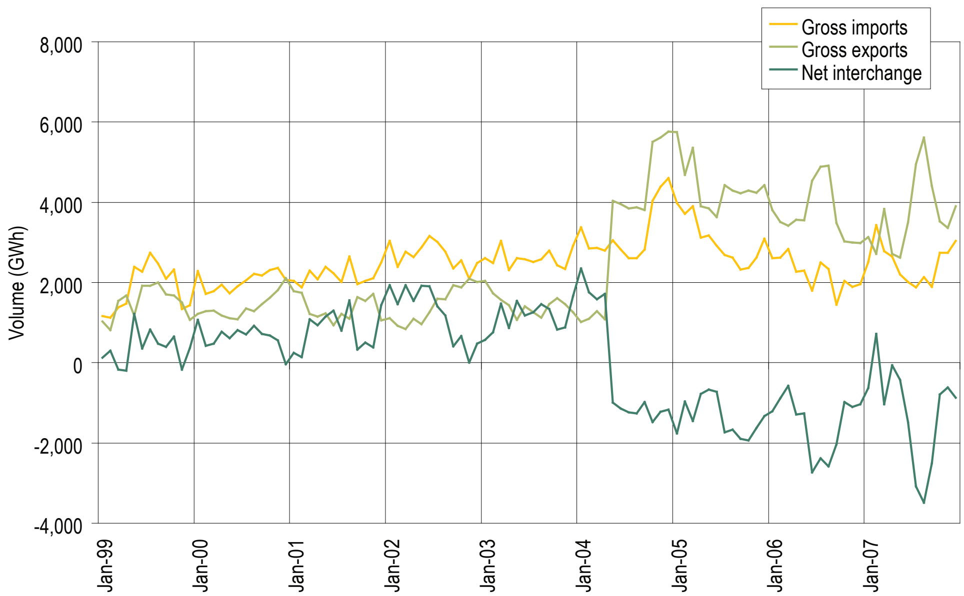


Figure 4-3 shows real-time import and export volume for PJM from 1999 through 2007. PJM became a consistent net exporter of energy in 2004 and has continued to be a net exporter since that time. During 2007, imports continued to be lower than exports, with the exception of February. Exports peaked in August while imports declined from February and net interchange had a record peak in August.

Figure 4-3 PJM scheduled import and export transaction volume history: Calendar years 1999 to 2007



Interface Imports and Exports

Total imports and exports are comprised of flows at each PJM interface.[11] Net interchange in the Real-Time Market is shown by interface for 2007 in Table 4-1 while gross imports and exports are shown in Table 4-2 and Table 4-3. Net interchange in the Day-Ahead Market is shown by interface for 2007 in Table 4-4 while gross imports and exports are shown in Table 4-5 and Table 4-6.

In 2007, there were net exports in the Real-Time Market at 18 of PJM's 23 interfaces. (See Table 4-8 for changes in defined interfaces during 2007.) The top three exporting interfaces accounted for 42 percent of the total net exports, PJM/TVA with 19 percent, PJM/MEC with 12 percent and PJM/NEPT with 11 percent of the net export volume. In 2007, there were net exports in the Day-Ahead Market at 16 of PJM's 23 interfaces. The top three exporting interfaces accounted for 54 percent of the total net exports, PJM/Northern Indiana Public Service Company (PJM/NIPS) with 27 percent, PJM/ALTW with 16 percent and PJM/MEC with 11 percent.

11 See "PJM Interface Price Definition Methodology" (September 14, 2007) (Accessed February 12, 2008) <http://www.pjm.com/committees/mic/downloads/20070925-item-06-definition-methodology.pdf> (97 KB).

There were net imports in the Real-Time Market at five of PJM's interfaces. Two net importing interfaces accounted for 95 percent of the net import volume, PJM/OVEC with 74 percent and PJM/DUK with 21 percent of the net import volume. There were net imports in the Day-Ahead Market at six of PJM's 23 interfaces. The top three net importing interfaces accounted for 98 percent of the total net imports, PJM/OVEC with 72 percent, PJM/NYIS and PJM/DUK each with 13 percent. The PJM/IP interface was in service only for the months of January and February. There was no Day-Ahead Market volume on that interface during those two months.

Table 4-1 Real-time scheduled net interchange volume by interface (GWh): Calendar year 2007

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
ALTE	(53.1)	(89.7)	(84.1)	(99.7)	(126.4)	(268.6)	(210.6)	(377.2)	(177.0)	(159.6)	(82.8)	(130.3)	(1,859.1)
ALTW	(91.2)	(83.6)	(92.6)	(88.3)	(183.1)	(194.3)	(276.7)	(284.0)	(253.0)	(104.7)	(95.6)	(98.1)	(1,845.2)
AMIL	0.0	0.0	(57.6)	(24.4)	2.0	52.9	6.0	(24.2)	51.6	101.6	82.2	77.9	268.0
AMRN	(112.2)	33.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(78.8)
CILC	1.0	(31.8)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(30.8)
CIN	(104.1)	(100.2)	(689.2)	(107.8)	18.9	(207.3)	(405.9)	(427.8)	(224.7)	(23.9)	109.5	75.3	(2,087.2)
CPLE	(100.4)	119.3	39.5	(115.6)	(2.0)	(104.1)	(204.8)	(214.7)	(194.0)	(77.9)	195.4	227.7	(431.6)
CPLW	(72.4)	(68.2)	(78.7)	(44.8)	0.0	(27.6)	(75.1)	(66.2)	(73.9)	(69.8)	(60.1)	(65.6)	(702.4)
CWLP	0.0	0.0	0.1	(1.1)	(0.1)	0.0	0.0	(123.9)	(29.8)	0.0	0.0	0.0	(154.8)
DUK	259.4	585.2	677.9	386.0	105.1	112.8	(49.2)	(393.7)	(121.7)	258.7	291.4	393.4	2,505.3
EKPC	(57.0)	(60.4)	(40.8)	(132.5)	(21.3)	(29.8)	(51.7)	(62.5)	(13.8)	(6.5)	(48.6)	(91.3)	(616.2)
FE	(97.5)	19.7	(73.4)	(162.4)	(180.6)	(48.5)	(88.0)	(8.8)	(6.9)	139.6	(155.5)	(102.6)	(764.9)
IP	3.6	7.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10.7
IPL	0.0	(12.7)	0.0	0.0	0.0	(130.4)	(274.0)	(133.6)	(242.7)	(126.2)	(9.2)	(8.1)	(936.9)
LGEE	65.8	16.5	0.2	(11.5)	7.5	1.1	52.0	12.1	15.0	65.8	25.6	97.5	347.6
MEC	(453.9)	(372.3)	(340.3)	(88.9)	(228.5)	(291.3)	(473.6)	(237.2)	(14.4)	(117.1)	(199.4)	(416.3)	(3,233.2)
MECS	(83.0)	(52.6)	(288.6)	(139.8)	(122.1)	(94.3)	(147.2)	(247.7)	(199.3)	(60.0)	(58.9)	(54.4)	(1,547.9)
NEPT	0.0	0.0	0.0	0.0	(23.6)	(146.3)	(422.5)	(397.8)	(442.3)	(487.7)	(455.2)	(438.8)	(2,814.2)
NIPS	4.1	(1.8)	(14.0)	4.9	(23.0)	(74.4)	(93.5)	(132.5)	(68.4)	(62.2)	(45.8)	(78.9)	(585.5)
NYIS	(58.5)	452.9	(52.9)	531.8	75.5	(361.2)	(629.4)	(323.0)	(651.4)	(338.4)	(361.6)	(749.9)	(2,466.1)
OVEC	860.9	838.3	771.2	680.3	672.0	710.1	691.7	718.9	710.9	692.0	743.5	758.5	8,848.3
TVA	(412.6)	(356.3)	(551.9)	(567.5)	(362.6)	(324.1)	(352.7)	(659.8)	(444.4)	(318.6)	(420.6)	(171.0)	(4,942.1)
WEC	(126.5)	(126.9)	(164.5)	(80.7)	(36.3)	(55.7)	(73.4)	(99.3)	(125.6)	(98.1)	(66.1)	(90.4)	(1,143.5)
Total	(627.6)	715.9	(1,039.7)	(62.0)	(428.6)	(1,481.0)	(3,078.6)	(3,482.9)	(2,505.8)	(793.0)	(611.8)	(865.4)	(14,260.5)

Table 4-2 Real-time scheduled gross import volume by interface (GWh): Calendar year 2007

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
ALTE	29.7	0.3	10.9	8.0	0.0	0.0	0.1	0.0	0.1	1.6	0.0	0.0	50.7
ALTW	0.3	0.0	0.2	0.0	0.1	0.4	0.0	0.0	0.0	0.0	0.0	0.0	1.0
AMIL	0.0	0.0	11.6	23.4	17.0	79.9	74.8	83.9	72.1	116.2	85.1	83.3	647.3
AMRN	66.6	99.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	166.2
CILC	1.4	1.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.8
CIN	180.1	109.8	47.9	126.3	180.1	51.6	77.1	179.4	103.8	209.4	216.9	265.4	1,747.8
CPLE	149.1	327.3	234.2	47.7	109.2	74.1	65.1	87.3	62.2	127.7	359.6	418.9	2,062.4
CPLW	0.0	0.0	2.7	0.0	0.0	0.1	1.4	0.2	0.0	0.0	0.0	0.0	4.4
CWLP	0.0	0.0	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2
DUK	328.6	659.8	753.7	471.0	224.8	267.0	240.9	107.4	158.4	377.5	401.9	486.4	4,477.4
EKPC	3.1	0.4	2.8	0.4	2.1	7.0	6.9	10.4	14.0	24.6	11.2	10.0	92.9
FE	93.2	214.2	143.7	45.9	40.9	187.6	124.1	215.8	177.6	347.9	52.0	104.4	1,747.3
IP	4.0	7.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	11.7
IPL	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	9.0	9.1
LGEE	67.3	23.9	21.3	19.6	31.1	22.4	55.9	20.7	20.9	69.8	37.5	103.1	493.5
MEC	147.6	110.8	109.5	198.9	81.7	53.0	33.5	82.4	186.1	158.6	159.5	150.8	1,472.4
MECS	13.0	21.8	18.2	57.1	75.2	58.5	55.2	57.9	36.3	88.9	52.6	120.9	655.6
NEPT	0.0	0.0	0.0	0.0	0.9	6.5	0.0	0.1	0.1	0.0	0.1	0.0	7.7
NIPS	18.4	1.6	7.5	25.8	19.6	10.0	2.4	3.7	17.2	12.4	5.7	6.1	130.4
NYIS	508.9	891.1	557.6	896.3	652.8	430.8	361.6	489.0	273.9	436.8	550.1	395.2	6,444.1
OVEC	865.5	845.4	772.1	688.4	676.5	716.2	714.8	721.9	727.5	715.0	767.9	786.8	8,998.0
TVA	28.2	110.3	94.2	41.7	84.2	45.8	62.2	69.2	38.5	49.5	46.2	101.6	771.6
WEC	4.3	1.2	0.1	0.0	0.0	0.3	1.3	1.0	0.1	0.8	0.5	0.0	9.6
Total	2,509.3	3,426.6	2,788.3	2,650.6	2,196.2	2,011.3	1,877.3	2,130.3	1,888.8	2,736.7	2,746.8	3,041.9	30,004.1

Table 4-3 Real-time scheduled gross export volume by interface (GWh): Calendar year 2007

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
ALTE	82.8	90.0	95.0	107.7	126.4	268.6	210.7	377.2	177.1	161.2	82.8	130.3	1,909.8
ALTW	91.5	83.6	92.8	88.3	183.2	194.7	276.7	284.0	253.0	104.7	95.6	98.1	1,846.2
AMIL	0.0	0.0	69.2	47.8	15.0	27.0	68.8	108.1	20.5	14.6	2.9	5.4	379.3
AMRN	178.8	66.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	245.0
CILC	0.4	33.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	33.6
CIN	284.2	210.0	737.1	234.1	161.2	258.9	483.0	607.2	328.5	233.3	107.4	190.1	3,835.0
CPLE	249.5	208.0	194.7	163.3	111.2	178.2	269.9	302.0	256.2	205.6	164.2	191.2	2,494.0
CPLW	72.4	68.2	81.4	44.8	0.0	27.7	76.5	66.4	73.9	69.8	60.1	65.6	706.8
CWLP	0.0	0.0	0.0	1.2	0.1	0.0	0.0	123.9	29.8	0.0	0.0	0.0	155.0
DUK	69.2	74.6	75.8	85.0	119.7	154.2	290.1	501.1	280.1	118.8	110.5	93.0	1,972.1
EKPC	60.1	60.8	43.6	132.9	23.4	36.8	58.6	72.9	27.8	31.1	59.8	101.3	709.1
FE	190.7	194.5	217.1	208.3	221.5	236.1	212.1	224.6	184.5	208.3	207.5	207.0	2,512.2
IP	0.4	0.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.0
IPL	0.0	12.7	0.0	0.0	0.0	130.5	274.0	133.6	242.7	126.2	9.2	17.1	946.0
LGEE	1.5	7.4	21.1	31.1	23.6	21.3	3.9	8.6	5.9	4.0	11.9	5.6	145.9
MEC	601.5	483.1	449.8	287.8	310.2	344.3	507.1	319.6	200.5	275.7	358.9	567.1	4,705.6
MECS	96.0	74.4	306.8	196.9	197.3	152.8	202.4	305.6	235.6	148.9	111.5	175.3	2,203.5
NEPT	0.0	0.0	0.0	0.0	24.5	152.8	422.5	397.9	442.4	487.7	455.3	438.8	2,821.9
NIPS	14.3	3.4	21.5	20.9	42.6	84.4	95.9	136.2	85.6	74.6	51.5	85.0	715.9
NYIS	567.4	438.2	610.5	364.5	577.3	792.0	991.0	812.0	925.3	775.2	911.7	1,145.1	8,910.2
OVEC	4.6	7.1	0.9	8.1	4.5	6.1	23.1	3.0	16.6	23.0	24.4	28.3	149.7
TVA	440.8	466.6	646.1	609.2	446.8	369.9	414.9	729.0	482.9	368.1	466.8	272.6	5,713.7
WEC	130.8	128.1	164.6	80.7	36.3	56.0	74.7	100.3	125.7	98.9	66.6	90.4	1,153.1
Total	3,136.9	2,710.7	3,828.0	2,712.6	2,624.8	3,492.3	4,955.9	5,613.2	4,394.6	3,529.7	3,358.6	3,907.3	44,264.6

Table 4-4 Day-ahead net interchange volume by interface (GWh): Calendar year 2007

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
ALTE	(83.0)	(90.2)	(99.7)	(112.8)	(148.8)	(191.6)	(269.3)	(182.0)	(50.0)	(48.0)	(119.2)	(139.9)	(1,534.5)
ALTW	(203.8)	(261.2)	(99.9)	(161.0)	(500.5)	(488.3)	(539.6)	(620.9)	(553.0)	(446.8)	(528.2)	(821.8)	(5,225.0)
AMIL	0.0	0.0	(7.7)	(8.1)	(11.5)	18.1	4.6	(22.0)	54.0	66.9	55.7	42.0	192.0
AMRN	4.5	(3.7)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8
CILC	0.0	(8.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(8.0)
CIN	(437.8)	(367.6)	(535.6)	(152.4)	(13.3)	32.4	(251.9)	(443.6)	(178.6)	(90.7)	56.4	(74.2)	(2,456.9)
CPLE	(287.6)	(16.8)	151.9	(110.1)	(47.4)	(89.3)	(142.3)	(147.3)	(113.5)	(76.1)	21.0	213.1	(644.4)
CPLW	(187.4)	(165.8)	(182.9)	(115.3)	2.4	(66.0)	(186.7)	(168.3)	(174.0)	(182.5)	(150.3)	(171.0)	(1,747.8)
CWLP	0.0	0.0	0.0	(1.2)	(0.1)	6.2	0.0	0.0	0.0	0.0	0.0	0.0	4.9
DUK	91.6	407.8	496.0	194.4	44.5	113.5	63.8	(258.2)	(63.0)	174.6	180.8	185.6	1,631.4
EKPC	(1.0)	(5.7)	(1.4)	(4.2)	(0.5)	2.4	12.1	1.3	0.0	3.7	0.0	(7.2)	(0.5)
FE	(156.0)	(257.5)	(190.5)	(168.2)	(76.0)	(36.0)	(75.0)	(146.4)	(153.6)	(188.8)	(160.1)	(137.3)	(1,745.4)
IP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	(0.1)	(0.1)	0.0	0.0	(18.5)	(126.1)	(86.0)	(197.7)	(70.2)	(55.0)	(37.5)	(165.5)	(756.7)
LGEE	1.6	0.0	0.0	0.0	(31.4)	12.0	3.3	1.7	2.8	1.8	5.7	(8.1)	(10.6)
MEC	(443.4)	(382.5)	(354.7)	(198.8)	(248.1)	(289.2)	(345.7)	(295.4)	(146.9)	(197.8)	(260.6)	(355.8)	(3,518.9)
MECS	(257.5)	(213.2)	(201.1)	(70.4)	(169.2)	(68.2)	(33.4)	(246.8)	(175.9)	(144.9)	(15.2)	(61.0)	(1,656.8)
NEPT	0.0	0.0	0.0	0.0	(10.6)	(165.9)	(419.8)	(392.2)	(434.2)	(477.9)	(448.0)	(441.0)	(2,789.6)
NIPS	(606.7)	(525.3)	(512.1)	(146.7)	(716.8)	(901.1)	(743.1)	(867.6)	(1,018.2)	(769.3)	(733.0)	(1,086.0)	(8,625.9)
NYIS	(268.8)	(661.7)	185.3	725.7	500.2	338.1	286.4	214.8	(78.6)	197.5	113.2	120.9	1,673.0
OVEC	952.4	929.4	766.4	705.9	607.7	837.6	763.1	660.8	634.2	635.1	678.6	718.6	8,889.8
TVA	(99.0)	(105.3)	(87.9)	(183.1)	(25.3)	129.9	68.9	(273.0)	(45.2)	102.5	158.0	162.2	(197.3)
WEC	(325.9)	(233.6)	(142.7)	(92.8)	(58.5)	(47.1)	(75.8)	(89.4)	(88.0)	(84.0)	(49.2)	(71.2)	(1,358.2)
Total	(2,307.9)	(1,961.0)	(816.6)	100.9	(921.7)	(978.6)	(1,966.4)	(3,472.2)	(2,651.9)	(1,579.7)	(1,231.9)	(2,097.6)	(19,884.6)

Table 4-5 Day-ahead gross import volume by interface (GWh): Calendar year 2007

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
ALTE	0.0	0.0	0.0	0.1	48.5	39.5	12.6	31.1	125.1	160.5	9.8	41.4	468.6
ALTW	0.0	0.0	0.0	0.0	17.2	23.7	2.0	6.5	54.1	54.1	27.0	27.3	211.9
AMIL	0.0	0.0	0.0	0.0	5.5	22.9	48.1	55.8	54.0	66.9	55.7	55.9	364.8
AMRN	8.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8.2
CILC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CIN	40.9	18.3	31.9	92.9	106.9	125.6	43.9	24.3	21.0	54.6	95.2	78.9	734.4
CPLE	78.1	132.9	272.7	87.0	89.0	27.6	0.0	2.3	1.2	18.2	118.6	310.1	1,137.7
CPLW	0.0	2.2	2.9	0.0	2.4	0.0	0.0	0.0	0.0	3.5	0.0	0.0	11.0
CWLP	0.0	0.0	0.0	0.0	0.0	6.2	0.0	0.0	0.0	0.0	0.0	0.0	6.2
DUK	95.9	421.2	496.4	205.3	79.3	143.0	125.5	59.3	102.9	204.4	236.1	216.1	2,385.4
EKPC	0.2	0.3	0.2	0.2	0.0	2.4	12.1	1.3	0.0	3.7	0.0	0.0	20.4
FE	50.8	72.2	137.5	117.3	221.8	81.8	64.8	8.9	39.6	19.9	6.1	19.9	840.6
IP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	0.0	0.0	0.0	0.0	32.8	13.1	21.4	4.4	2.1	3.3	4.5	5.1	86.7
LGEE	1.6	0.0	0.0	0.0	6.5	19.5	22.0	5.2	4.0	2.4	30.4	13.0	104.6
MEC	4.6	6.4	0.2	3.4	0.2	0.0	0.0	0.0	21.4	6.3	0.0	3.0	45.5
MECS	5.0	27.7	33.0	71.2	69.4	149.3	196.6	137.5	236.8	182.7	263.2	189.3	1,561.7
NEPT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NIPS	3.2	0.3	178.5	402.8	336.7	133.5	73.3	36.6	33.8	93.0	63.8	12.1	1,367.6
NYIS	334.4	304.5	547.9	855.2	666.0	500.8	589.0	411.2	309.8	361.5	337.8	414.6	5,632.7
OVEC	952.4	929.8	766.5	705.9	615.1	844.5	825.8	717.7	735.6	710.7	699.9	751.9	9,255.8
TVA	7.6	105.0	108.4	42.9	30.8	140.5	105.7	48.5	71.2	182.7	258.0	233.0	1,334.3
WEC	0.6	0.0	0.0	0.2	14.3	7.2	0.1	0.1	9.9	0.0	0.0	4.8	37.2
Total	1,583.5	2,020.8	2,576.1	2,584.4	2,342.4	2,281.1	2,142.9	1,550.7	1,822.5	2,128.4	2,206.1	2,376.4	25,615.3

Table 4-6 Day-ahead gross export volume by interface (GWh): Calendar year 2007

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
ALTE	83.0	90.2	99.7	112.9	197.3	231.1	281.9	213.1	175.1	208.5	129.0	181.3	2,003.1
ALTW	203.8	261.2	99.9	161.0	517.7	512.0	541.6	627.4	607.1	500.9	555.2	849.1	5,436.9
AMIL	0.0	0.0	7.7	8.1	17.0	4.8	43.5	77.8	0.0	0.0	0.0	13.9	172.8
AMRN	3.7	3.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7.4
CILC	0.0	8.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8.0
CIN	478.7	385.9	567.5	245.3	120.2	93.2	295.8	467.9	199.6	145.3	38.8	153.1	3,191.3
CPLE	365.7	149.7	120.8	197.1	136.4	116.9	142.3	149.6	114.7	94.3	97.6	97.0	1,782.1
CPLW	187.4	168.0	185.8	115.3	0.0	66.0	186.7	168.3	174.0	186.0	150.3	171.0	1,758.8
CWLP	0.0	0.0	0.0	1.2	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.3
DUK	4.3	13.4	0.4	10.9	34.8	29.5	61.7	317.5	165.9	29.8	55.3	30.5	754.0
EKPC	1.2	6.0	1.6	4.4	0.5	0.0	0.0	0.0	0.0	0.0	0.0	7.2	20.9
FE	206.8	329.7	328.0	285.5	297.8	117.8	139.8	155.3	193.2	208.7	166.2	157.2	2,586.0
IP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	0.1	0.1	0.0	0.0	51.3	139.2	107.4	202.1	72.3	58.3	42.0	170.6	843.4
LGEE	0.0	0.0	0.0	0.0	37.9	7.5	18.7	3.5	1.2	0.6	24.7	21.1	115.2
MEC	448.0	388.9	354.9	202.2	248.3	289.2	345.7	295.4	168.3	204.1	260.6	358.8	3,564.4
MECS	262.5	240.9	234.1	141.6	238.6	217.5	230.0	384.3	412.7	327.6	278.4	250.3	3,218.5
NEPT	0.0	0.0	0.0	0.0	10.6	165.9	419.8	392.2	434.2	477.9	448.0	441.0	2,789.6
NIPS	609.9	525.6	690.6	549.5	1,053.5	1,034.6	816.4	904.2	1,052.0	862.3	796.8	1,098.1	9,993.5
NYIS	603.2	966.2	362.6	129.5	165.8	162.7	302.6	196.4	388.4	164.0	224.6	293.7	3,959.7
OVEC	0.0	0.4	0.1	0.0	7.4	6.9	62.7	56.9	101.4	75.6	21.3	33.3	366.0
TVA	106.6	210.3	196.3	226.0	56.1	10.6	36.8	321.5	116.4	80.2	100.0	70.8	1,531.6
WEC	326.5	233.6	142.7	93.0	72.8	54.3	75.9	89.5	97.9	84.0	49.2	76.0	1,395.4
Total	3,891.4	3,981.8	3,392.7	2,483.5	3,264.1	3,259.7	4,109.3	5,022.9	4,474.4	3,708.1	3,438.0	4,474.0	45,499.9

Interface Pricing Points

Interface pricing points differ from interfaces. Transactions can be scheduled to an interface based on a contract transmission path, but pricing points are developed and applied based on the estimated electrical impact of the external power source on PJM tie lines, regardless of contract transmission path. PJM establishes prices for transactions with external control areas by assigning interface pricing points to individual control areas. Interface pricing points are designed to reflect the way a transaction from or to an external area actually impacts PJM electrically for areas that are both adjacent to, and not adjacent to, PJM. However, this analysis is an approximation given the complexity of the transmission network outside PJM and the dynamic nature of power flows. Transactions between PJM and external control areas need to be priced at the PJM border. A set of external buses is used to create such interface prices.[12] The challenge is to create an interface price, composed of external pricing points, that accurately represents flows between PJM and external sources of energy and, therefore, to create price signals that embody underlying economic fundamentals.[13]

12 See PJM. "LMP Aggregate Definitions" (December 12, 2007) (Accessed January 29, 2008) <http://www.pjm.com/markets/energy-market/downloads/20071211-aggregate-definitions.xls> (1,334 KB). PJM periodically updates these definitions on its Web site. See <http://www.pjm.com>.

13 See the *2007 State of the Market Report*, Volume II, Appendix D, "Interchange Transactions," for a more complete discussion of the development of pricing points.

Table 4-7 presents the interface pricing points used during 2007. These pricing points include all those used at the end of 2006 plus the addition of the NEPT pricing point. The NEPT pricing point was added in July when the Neptune line went into commercial service.

Table 4-7 Active pricing points: Calendar year 2007

PJM 2007 Pricing Points				
MICHFE	MISO	NEPT	NIPSCO	Northwest
NYIS	Ontario IESO	OVEC	SOUTHEXP	SOUTHIMP

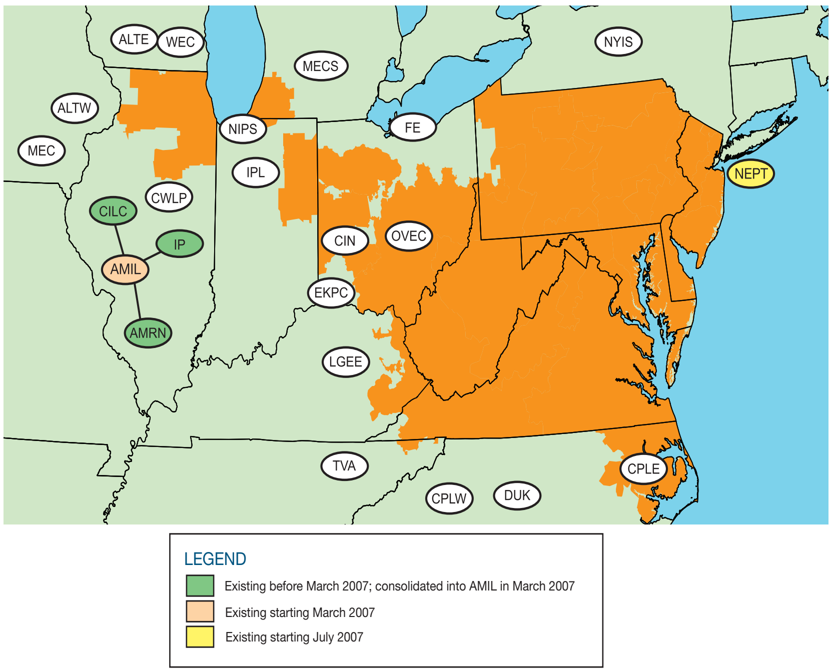
In March 2007, the Ameren (AMRN), Central Illinois Light Company (CILC) and Illinois Power Company (IP) control areas merged. As a result, PJM modified its interfaces. The PJM/AMRN, PJM/CILC and PJM/IP interfaces were retired and a new PJM/Ameren – Illinois (AMIL) Interface was created. In July 2007, the Neptune direct current (DC) transmission line was placed into commercial service. This addition created the new PJM/NEPT Interface. Table 4-8 presents the interfaces used during 2007.

Table 4-8 Active interfaces: Calendar year 2007

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
ALTE	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
ALTW	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
AMIL			Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
AMRN	Active	Active										
CILC	Active	Active										
CIN	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
CPLE	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
CPLW	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
CWLP	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
DUK	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
EKPC	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
FE	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
IP	Active	Active										
IPL	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
LGEE	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
MEC	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
MECS	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
NEPT							Active	Active	Active	Active	Active	Active
NIPS	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
NYIS	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
OVEC	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
TVA	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
WEC	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active

The approximate geographic location of these interfaces can be seen in Figure 4-4.

Figure 4-4 PJM's footprint and its external interfaces



Interchange Transaction Topics

There are six topics associated with interchange transactions that require more detailed discussion: interface pricing results with the Midwest ISO and NYISO; the frequency of TLRs; PJM's continued operations under agreements with bordering areas; new interface pricing agreements with individual companies; the Con Edison – PSE&G wheeling contract and the addition of the Neptune transmission line.

PJM Interface Prices with Organized Markets

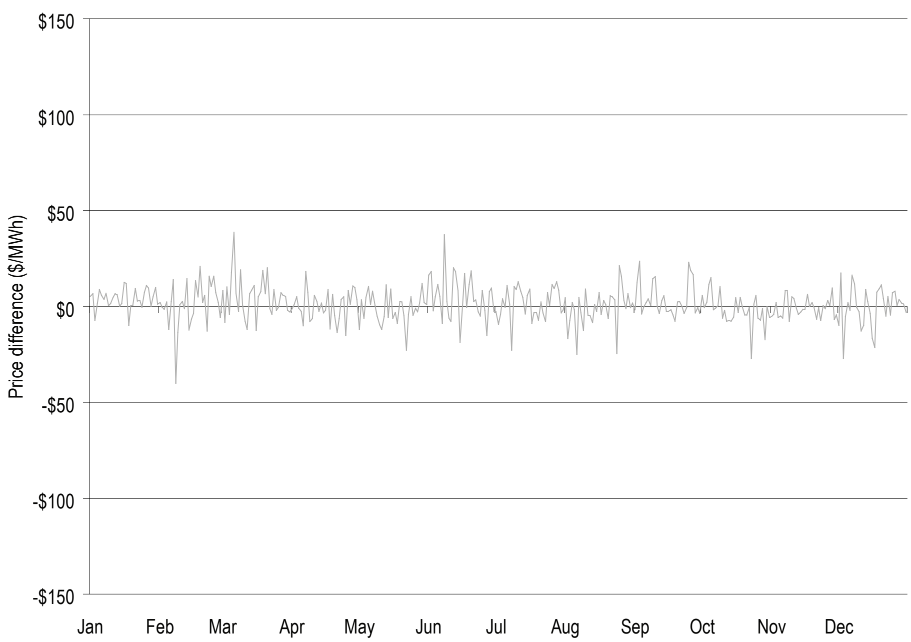
During 2007, prices at the borders between PJM and the Midwest ISO and between PJM and the NYISO were consistent with competitive forces.

PJM and Midwest ISO Interface Prices

On April 1, 2005, with the introduction of price-based markets, the Midwest ISO created a new interface pricing point with PJM. Both the PJM/MISO and the MISO/PJM pricing points represent the value of power at the relevant border, as determined by each market. In both cases, the interface price is the price at which transactions are settled. For example, a transaction into PJM from Midwest ISO would receive the PJM/MISO price upon entering PJM, while a transaction into Midwest ISO from PJM would receive the MISO/PJM price when entering Midwest ISO. PJM and Midwest ISO use network models to determine these prices and to ensure that the prices are consistent with the underlying electrical flows. PJM uses the LMP at nine buses[14] within Midwest ISO to calculate the PJM/MISO Interface price while Midwest ISO uses all of the PJM generator buses in its model of the PJM system in its computation of the MISO/PJM Interface price.[15]

The 2007 hourly average interface prices for PJM/MISO and MISO/PJM were $45.46 and $46.72, respectively. The simple average difference between the MISO/PJM Interface price and the PJM/MISO Interface price was $1.26 in 2007, 3 percent of the average PJM/MISO price. (See Figure 4-5.) The MISO/PJM Interface price was slightly higher on average than the PJM/MISO price in 2007.

Figure 4-5 Daily hourly average price difference (Midwest ISO Interface minus PJM/MISO): Calendar year 2007



The simple average interface price difference does not reflect the underlying hourly variability in prices. There are a number of relevant measures of variability, including the number of times the price differential fluctuates between positive and negative, the standard deviation of individual prices and of price differences and the absolute value of the price differences.

During 2007, the difference between the PJM/MISO Interface price and the MISO/PJM Interface price fluctuated between positive and negative about nine times per day. The standard deviation of the hourly price was $27.41 for the PJM/MISO price and $31.00 for the MISO/PJM Interface price. The standard deviation of the difference in interface prices was $25.00. The average of the absolute value of the hourly price difference was $15.26. Absolute values reflect price differences regardless of whether they are positive or negative.

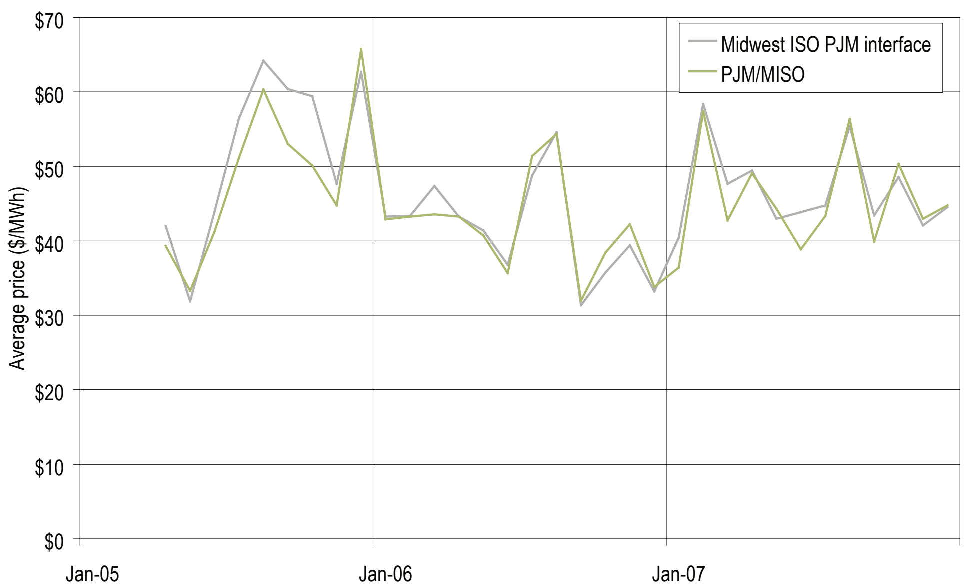
14 See PJM. "LMP Aggregate Definitions" (December 12, 2007) (Accessed January 29, 2008) <http://www.pjm.com/markets/energy-market/downloads/20071211-aggregate-definitions.xls> (1,334 KB). PJM periodically updates these definitions on its Web site. See <http://www.pjm.com>.

15 Based on information obtained from the Midwest ISO Extranet (February 19, 2008) <http://extranet.midwestiso.org>.

Several factors are responsible for the relationship between interface prices. The simple average interface price difference suggests that competitive forces prevent price deviations from persisting, an observation further supported by the frequency with which price differential switches between positive and negative.

In addition, there is a significant correlation between monthly average hourly PJM and Midwest ISO interface prices during the 2007 period. Figure 4-6 shows this correlation between hourly PJM and Midwest ISO interface prices.

Figure 4-6 Monthly hourly average Midwest ISO PJM Interface price and the PJM/MISO price: April 2005 to 2007



The difference in PJM and MISO interface prices can also be measured by comparing the LMP for pairs of generating units that are located close together but on opposite sides of the border between PJM and the Midwest ISO and by comparing the LMP for jointly owned units that participate in both markets. The MMU compared two pairs of units and two jointly owned units. The LMP differences were compared over three time periods: calendar year 2006, January through May 2007 (i.e., the pre-marginal loss implementation period) and June through December 2007 (i.e., the post-marginal loss implementation period).

Table 4-9 shows that in 2006 all of the unit pairs and jointly owned units had LMP differences larger than the difference at the PJM/MISO Interface. After the implementation of marginal losses in PJM, the units all showed decreases in their LMP differences while also moving closer to the difference observed at the interface. While the sample is not adequate to permit general conclusions, the data from these units indicate that actual price differences at the border between PJM and the Midwest ISO have varied from the interface pricing differences.

Table 4-9 Average LMP difference (PJM minus Midwest ISO): January 1, 2006, through December 31, 2007

	2006	2007 (Pre-Marginal Losses)	2007 (Post-Marginal Losses)
Kincaid (PJM) & Coffeen (MISO)	$5.87	$4.31	$5.76
Beaver Valley (PJM) & Mansfield (MISO)	$2.28	($2.64)	$0.55
Miami Fort (PJM) & (MISO)	$1.95	($1.30)	($0.95)
Stuart (PJM) & (MISO)	$2.09	($0.81)	($0.64)
PJM/MISO Interface	($0.23)	($1.83)	($0.85)

PJM and NYISO Interface Prices

If interface prices were defined in a comparable manner by PJM and NYISO, if identical rules governed external transactions in PJM and NYISO, if time lags were not built into the rules governing such transactions and if no risks were associated with such transactions, then prices at the interfaces would be expected to be very close and the level of transactions would be expected to be related to any price differentials. The fact that none of these conditions exists is important in explaining the observed relationship between interface prices and inter-ISO power flows, and those price differentials.[16]

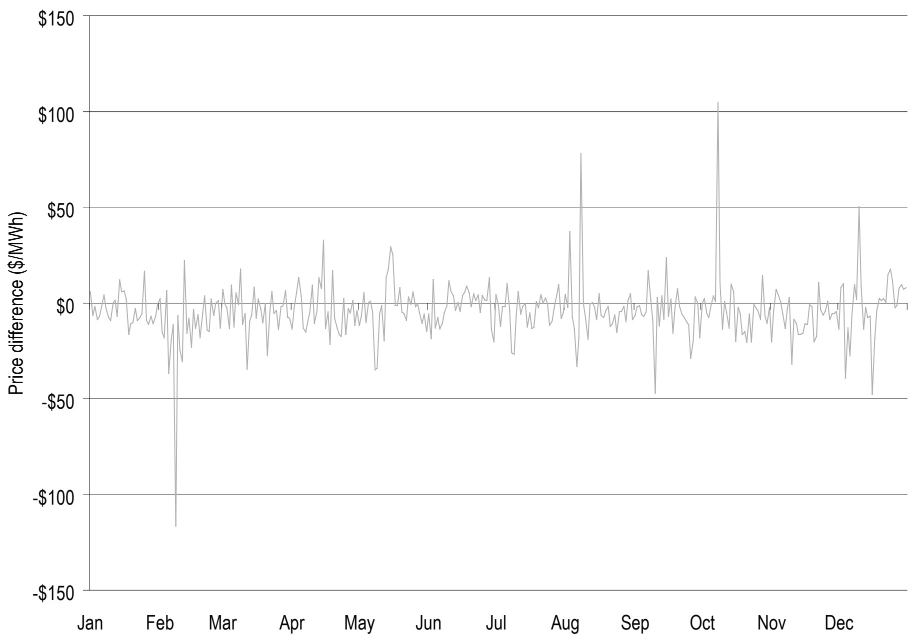
PJM's price for transactions with NYISO, termed the NYIS pricing point by PJM, represents the value of power at the PJM-NYISO border, as determined by the PJM market. PJM defines its NYIS pricing point using two buses.[17] Similarly, the NYISO's price for transactions with PJM, termed the PJM proxy bus by the NYISO, represents the value of power at the NYISO-PJM border, as determined by the NYISO market. In the NYISO market, transactions are required to have a price associated with them. Import transactions are treated as generator offers at the NYISO/PJM proxy bus. Export transactions are treated as load bids. Competing bids and offers are evaluated along with the other NYISO resources and a proxy bus price is derived.

The 2007 hourly average price for PJM/NYIS and the NYISO/PJM proxy bus price were $61.92 and $57.85, respectively. The simple average difference between the PJM/NYIS Interface price and the NYISO/PJM proxy bus price increased from -$2.47 per MWh in 2006 to -$4.07 per MWh in 2007, and the variability of the difference also increased. (See Figure 4-7.) PJM's net export volume to New York for 2007 was 76 percent lower than the six-year, 2001 to 2006, average. This is consistent with the fact that the difference between the PJM/NYIS price and the NYISO/PJM price increased.

16 See also the discussion of these issues in the *2005 State of the Market Report*, Section 4, "Interchange Transactions" (March 8, 2006).

17 See PJM. "LMP Aggregate Definitions" (December 12, 2007) (Accessed January 29, 2008) <http://www.pjm.com/markets/energy-market/downloads/20071211-aggregate-definitions.xls> (1,334 KB). PJM periodically updates these definitions on its Web site. See <http://www.pjm.com>.

Figure 4-7 Daily hourly average price difference (NY proxy - PJM/NYIS): Calendar year 2007



The simple average interface price difference does not reflect the underlying hourly variability in prices. There are a number of relevant measures of variability, including the number of times the price differential fluctuates between positive and negative, the standard deviation of individual prices and of price differences and the absolute value of the price differences.

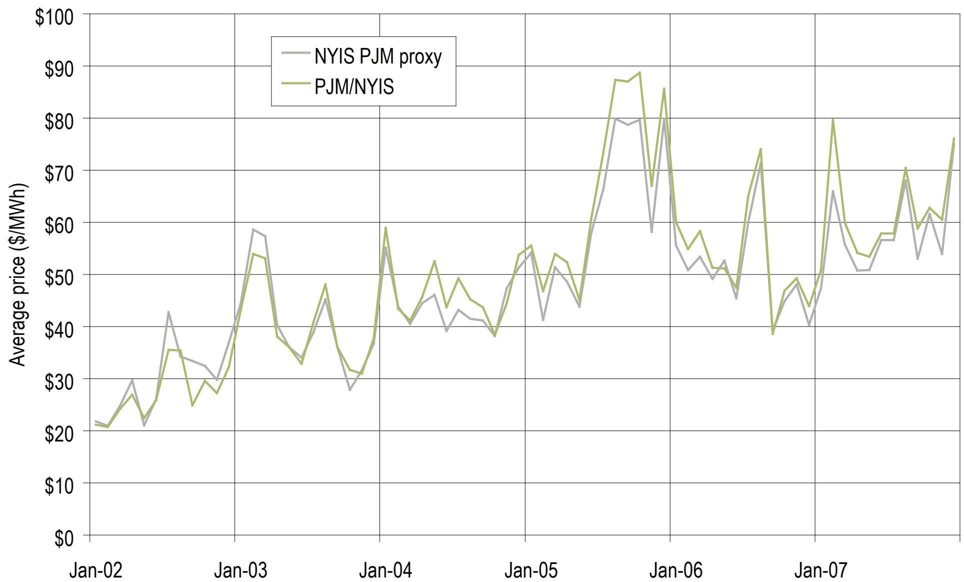
The difference between the PJM/NYIS Interface price and the NYISO/PJM price continued to fluctuate between positive and negative about eight times per day during 2007 as it has since 2003. The standard deviation of hourly price was $38.30 in 2007 for the PJM/NYIS price and $44.51 in 2007 for the NYISO/PJM proxy bus price. The standard deviation of the difference in interface prices was $43.60 in 2007. The average of the absolute value of the hourly price difference was $21.86 in 2007. Absolute values reflect price differences without regard to whether they are positive or negative.

A number of factors are responsible for the observed relationship between interface prices. The fact that the simple average of interface price differences is relatively small suggests that competitive forces prevent price deviations from persisting. That is further supported by the frequency with which the price differential switches between positive and negative. However, continuing significant variability in interface prices is consistent with the fact that interface prices are defined and established differently, making it difficult for prices to equalize, regardless of other factors.[18]

18 As previously noted, institutional difference between PJM and NYISO markets partially explains observed differences in border prices. For a description of those differences, see the *2005 State of the Market Report*, Appendix D, "Interchange Transactions" (March 8, 2006), pp. 195-198.

There has been a significant correlation between monthly average hourly PJM and NYISO interface prices during the entire period 2002 to 2007. Figure 4-8 shows this correlation between hourly PJM and NYISO interface prices.

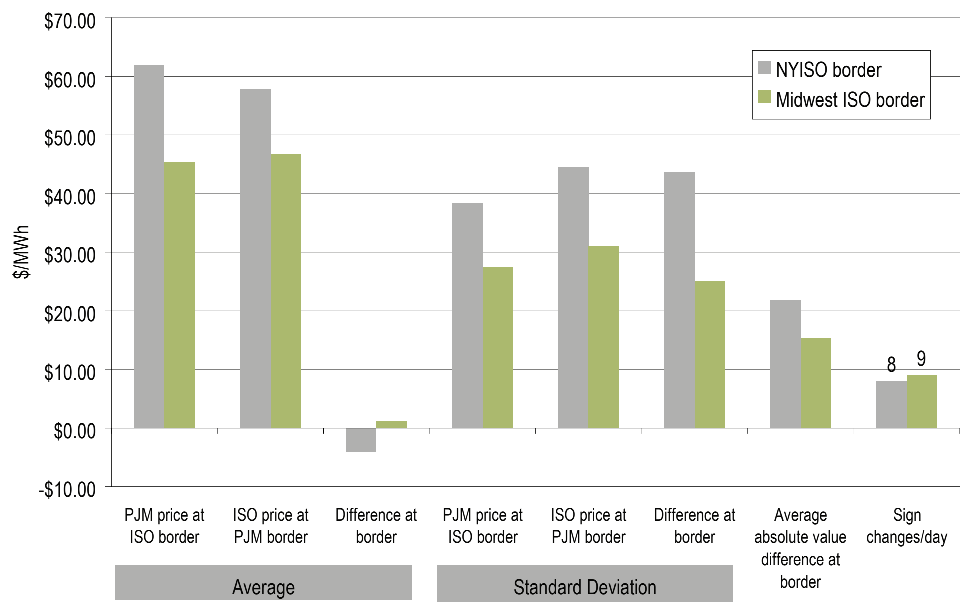
Figure 4-8 Monthly hourly average NYISO/PJM proxy bus price and the PJM/NYIS price: Calendar years 2002 to 2007



Summary of Interface Prices between PJM and Organized Markets

The key features of PJM interface pricing with the Midwest ISO and with the NYISO are summarized and compared in Figure 4-9, including average prices and measures of variability.

Figure 4-9 PJM, NYISO and Midwest ISO border price averages: Calendar year 2007



PJM TLRs

TLRs are called to control flows on electrical facilities when economic redispatch cannot solve overloads on those facilities. TLRs are generally called to control flows related to external control areas as redispatch within an LMP market can generally resolve overloads on internal transmission facilities. PJM called fewer TLRs in 2007 than in 2006. Total PJM TLRs declined by 41 percent, from 136 during 2006 to 80 in 2007. (See Figure 4-10.) In addition, the number of different flowgates for which PJM declared TLRs decreased from 41 different flowgates during 2006 to 38 different flowgates in 2007. (See Figure 4-11.) Of the 80 TLRs called by PJM in 2007, three facilities comprised 33 percent of the total. The three facilities were:

- Roseland – Cedar Grove F 230 kV Line for Loss of Roseland – Cedar Grove B 230 kV Line. These parallel path lines are located in northern New Jersey. Power transfers to New York and loop flows are the main reasons for TLRs on this line (nine TLRs in 2007; 29 TLRs in 2006);

- Kammer #200 765 to 500 kV Transformer for Loss of Belmont – Harrison 500 kV Line. This is a 765 to 500 kV transformer located near the border of Ohio and West Virginia. The Belmont – Harrison 500 kV line runs in northern West Virginia near the southwest corner of Pennsylvania. Economic dispatch of lower cost units in the west can cause high flows at Kammer. This constraint is not easily controllable with redispatch because of lack of generation with the necessary impact (nine TLRs in 2007; 16 TLRs in 2006); and

- **Person – Halifax 230 kV Line for Loss of Wake – Carson 500 kV Line.** These lines are located in southern Virginia and North Carolina. Power flows to/from PJM's southern neighbors, loop flows and heavy power flows in either the north-to-south or south-to-north direction at PJM's southeastern border are the main reasons for TLRs on this line (eight TLRs in 2007; no TLRs in 2006).

Midwest ISO called slightly more TLRs in 2007 than in 2006. Total Midwest ISO TLRs increased by less than 3 percent, from 796 during 2006 to 819 in 2007. (See Figure 4-10.)

Figure 4-10 PJM and Midwest ISO TLR procedures: Calendar years 2006 and 2007

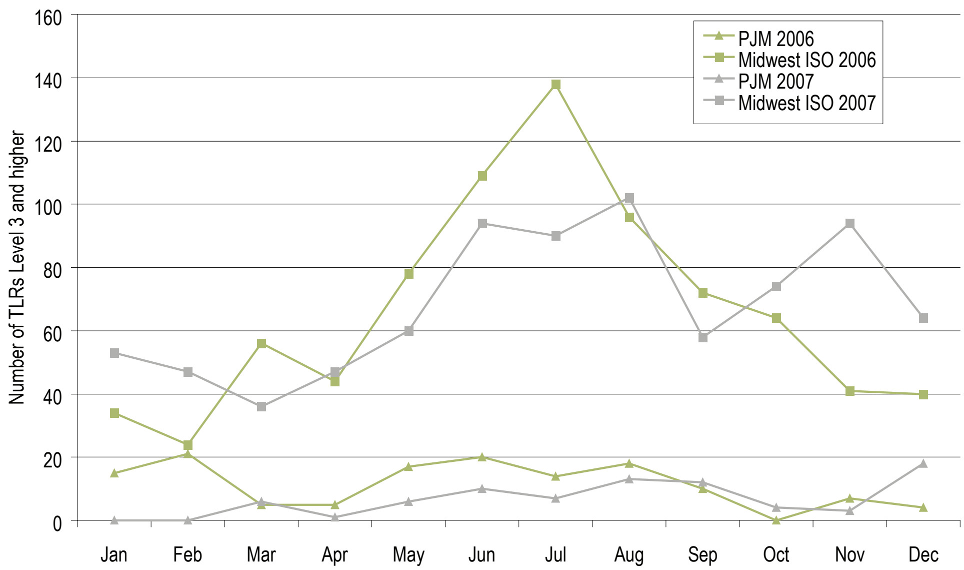


Figure 4-11 Number of different PJM flowgates that experienced TLRs: Calendar years 2006 to 2007

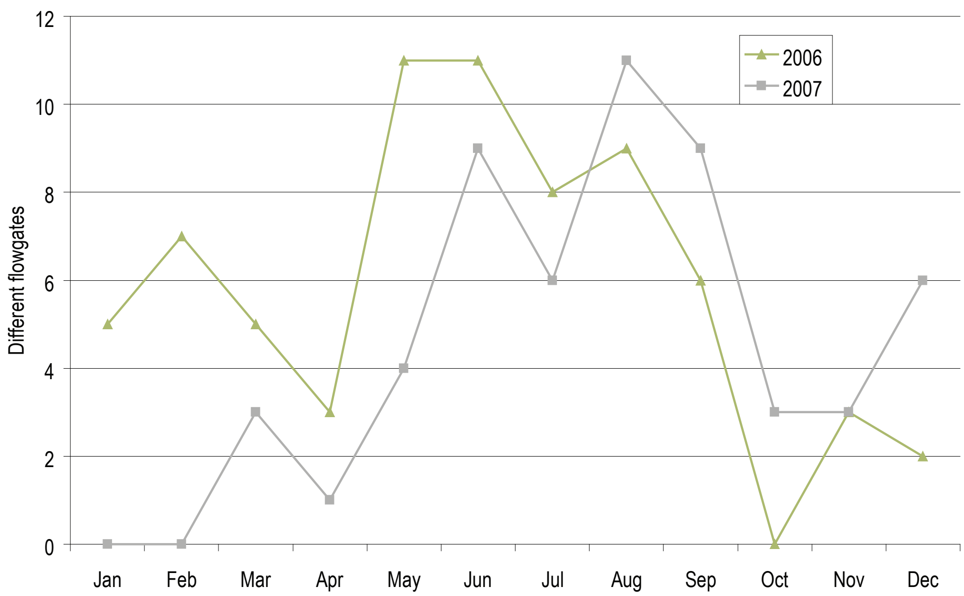
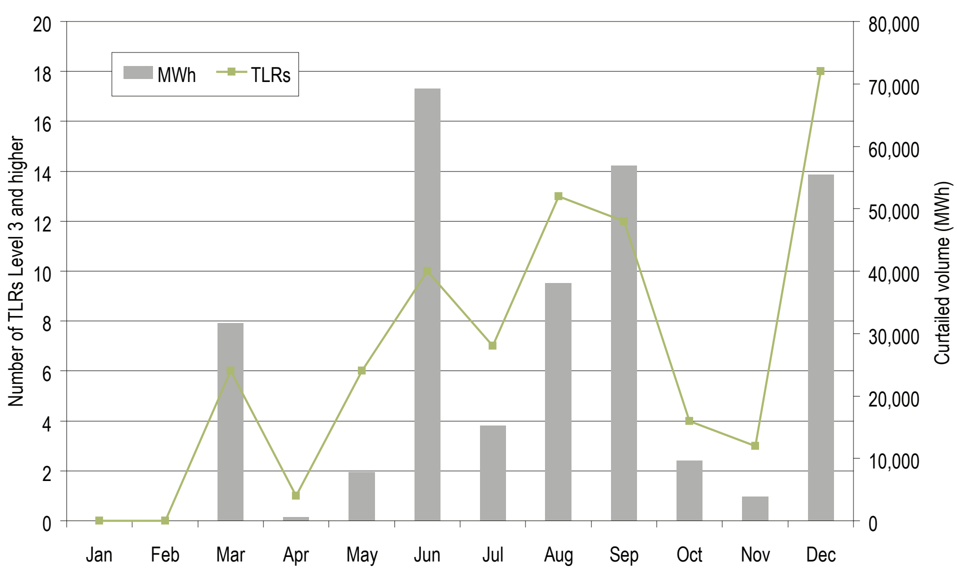


Figure 4-12 Number of PJM TLRs and curtailed volume: Calendar year 2007



Operating Agreements with Bordering Areas

To improve reliability and reduce potential competitive seams' issues, PJM and its neighbors have developed and continue to work on joint operating agreements. These agreements are in various stages of development and include a new reliability agreement with NYISO, an implemented operating agreement with Midwest ISO, an implemented reliability agreement with TVA, an operating agreement with Progress Energy Carolinas, Inc. that is not yet fully implemented and a reliability coordination agreement with VACAR South.

PJM and New York Independent System Operator Joint Operating Agreement (JOA)

On May 22, 2007, the JOA between PJM and NYISO became effective. This agreement was developed to improve reliability and includes obligations concerning: maintaining interconnected operations, voltage control and reactive power; coordinating scheduled outages and transmission planning; and providing emergency assistance. It also formalizes the process of electronic checkout of schedules, the exchange of interchange schedules to facilitate calculations for available transfer capability (ATC) and standards for interchange revenue metering. This agreement references and confirms earlier PJM/NYISO agreements, protocols and procedures. These remain in effect. This agreement does not include provisions for market-based congestion management or other market-to-market activity. PJM and NYISO should develop market-based congestion management protocols as soon as practicable.

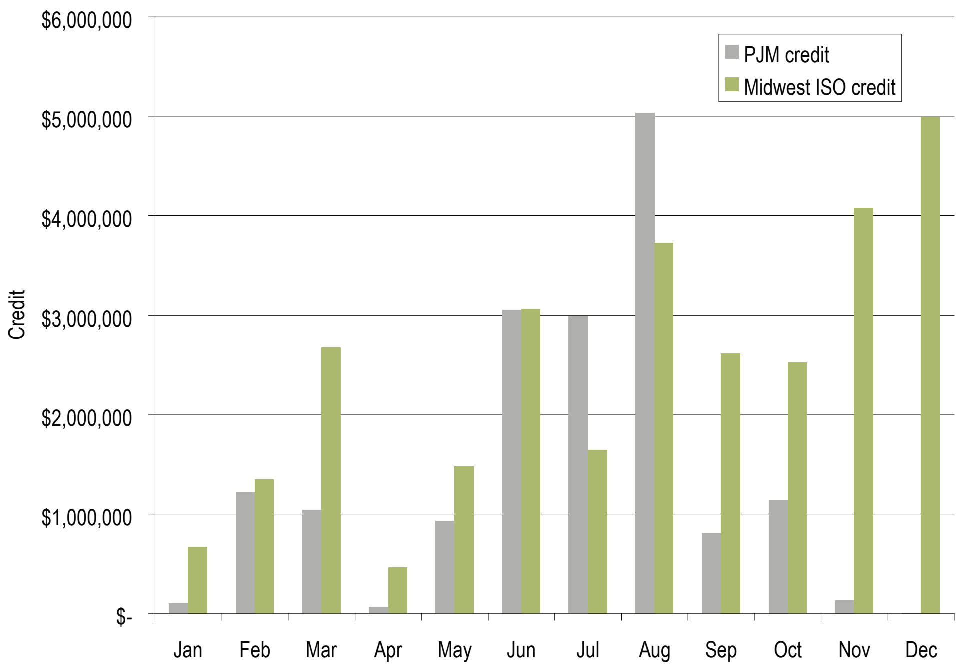
PJM and Midwest ISO Joint Operating Agreement (JOA)

On April 1, 2005, the Midwest ISO market became operational. That triggered the second, market-to-market phase, of the JOA. This second phase remained in effect through 2007.

Under the market-to-market rules, the organizations coordinate pricing at their borders. PJM and the Midwest ISO each calculates locational marginal price (LMP) for its interface with the other organization. Both entities calculate LMPs using network models including distribution factor impacts. PJM uses nine buses within the Midwest ISO to calculate the PJM/MISO pricing point LMP while the Midwest ISO uses all of the PJM generator buses in its model of the PJM system in its computation of the MISO/PJM pricing point.

In 2007, the market-to-market operations resulted both in Midwest ISO and PJM redispatching units to control congestion in the other's area and in the exchange of payments for this redispatch. Figure 4-13 presents the monthly credits each organization received from redispatching for the other. The largest payments from PJM to Midwest ISO during the year were the result of redispatch by Midwest ISO to relieve congestion on the Eau Clair — Arpin 345 kV line. Total PJM payments to Midwest ISO were $26.1 million, a 74 percent increase from the 2006 level. The largest payments from Midwest ISO to PJM during the year were the result of redispatch by PJM to relieve congestion on the Darwin — Eugene 345 kV line for loss of the Jefferson — Rockport 765 kV line. Total Midwest ISO payments to PJM were $13.4 million, a 24.3 percent decrease from the 2006 level.

Figure 4-13 Credits for coordinated congestion management: Calendar year 2007



PJM, Midwest ISO and TVA Joint Reliability Coordination Agreement

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 2007. Information-sharing among the parties enables each transmission provider to recognize and manage the effects of its operations on the adjoining systems. Additionally, the three organizations conduct joint planning sessions to ensure that improvements to their integrated systems are undertaken in a cost-effective manner and without adverse reliability impacts on any organization's customers.

PJM and Progress Energy Carolinas, Inc. Joint Operating Agreement

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 2007. Since Progress Energy Carolinas is not a market system, the coordination between PEC and PJM is similar to that between the Midwest ISO and PJM during the first phase of their JOA. The details that had been expected to be completed during the first half of 2006 remained under development during 2007. A phased approach is being discussed.

PJM and VACAR South Reliability Coordination Agreement

On May 23, 2007, PJM and VACAR South entered into a reliability coordination agreement. This agreement was developed to augment and further support reliability. It provides for system and outage coordination, emergency procedures and the exchange of data. This arrangement permits each party to coordinate its plans and operations in the interest of reliability. Provisions are also made for making regional studies and recommendations to improve the reliability of the interconnected bulk power systems.

Interface Pricing Agreements with Individual Companies

PJM entered into locational interface pricing agreements with three companies in 2007 that extend the concept of the dynamic scheduling of individual units to entire control areas. These agreements were posted by PJM on October 10, 2007, after a request by the MMU. Each of these agreements established a locational price for power sales between PJM and the individual company that applies under specified conditions and that differs from the generally applicable interface price. The purpose was to make sales and purchases at a price reflective of power flows between PJM and each control area individually. The agreements set out the protocols necessary to assure that the power flows sink (or source) only from each company's control area. The protocols include rules that govern when the identified LMP is available. When the company desires to sell into PJM, the rules require the company not to have simultaneous imports from other areas. Similarly, when a company wants to purchase from PJM, it cannot be simultaneously exporting to other areas. The three companies involved and the effective date of their agreements are: Duke Energy Carolinas, January 5, 2007;[19] Progress Energy Carolinas, February 13, 2007;[20] and North Carolina Municipal Power Agency (NCMPA), March 19, 2007.[21]

A potential issue with these agreements is the inability of other participants to receive comparable prices for comparable power flows. For example, if a participant is purchasing from one of the companies and then selling that power to PJM, that participant would receive the SOUTHIMP LMP while, at the same time, the company may be receiving its specific LMP if it is following the protocol. If the protocol was being followed, the source of power in both cases would be the same units.

PJM needs to ensure that such pricing is transparent and that all participants have access to the defined pricing when in the same position.

For the periods of time that each agreement was in effect, Table 4-10 shows the LMP calculated per the agreement and, for comparison, the SOUTHIMP and SOUTHEXP LMPs. The difference between the LMP under the agreements and PJM's SOUTHIMP LMP ranged from $2.32 with Duke to $5.12 with PEC while the difference between the LMP under the agreements and PJM's SOUTHEXP LMP ranged from $2.80 with NCMPA to $5.52 with PEC.

19 See "Duke Energy Carolinas Interface Pricing Arrangements" (January 5, 2007) (Accessed January 29, 2008) <http://www.pjm.com/documents/downloads/agreements/duke-pricing-agreement.pdf> (171 KB).

20 See "Progress Energy Carolinas, Inc. Interface Pricing Arrangements" (February 13, 2007) (Accessed January 29, 2008) <http://www.pjm.com/documents/downloads/agreements/pec-pricing-agreement.pdf> (210 KB).

21 See "North Carolina Municipal Power Agency Number 1 Interface Pricing Arrangement" (March 19, 2007) (Accessed January 29, 2008) <http://www.pjm.com/documents/downloads/agreements/electricities-pricing-agreement.pdf> (279 KB).

Table 4-10 Average hourly LMP comparison for Duke, PEC and NCMPA: For the time period in 2007 when the applicable agreement was in effect

	LMP	SOUTHIMP	SOUTHEXP	LMP - SOUTHIMP	LMP - SOUTHEXP
Duke	$51.63	$49.31	$48.70	$2.32	$2.93
PEC	$55.03	$49.91	$49.51	$5.12	$5.52
NCMPA	$51.77	$49.14	$48.97	$2.63	$2.80

Con Edison and PSE&G Wheeling Contracts

To help meet the demand for power in New York City, Con Edison uses electricity generated in upstate New York and wheeled through New York and New Jersey. A common path is through Westchester County using lines controlled by NYISO. Another path is through northern New Jersey using lines controlled by PJM. This wheeled power creates loop flow across the PJM system. The Con Edison/PSE&G contracts governing the New Jersey path evolved during the 1970s and were the subject of a Con Edison complaint to the FERC in 2001. In May 2005, the FERC issued an order setting out a protocol developed by the two companies, PJM and NYISO.[22] In July 2005, the protocol was implemented. Con Edison filed a protest with the FERC regarding the delivery performance in January 2006.[23]

PJM continued to operate under the terms of the protocol during 2007 while continuing to pursue work on the 19 items identified in the work plan to improve protocol performance. In August the FERC denied a rehearing request on Con Edison's complaints regarding protocol performance and refunds.[24]

The protocol allows Con Edison to elect up to the flow specified in each contract through the PJM Day-Ahead Energy Market. These elections are transactions in the PJM Day-Ahead Energy Market. The 600 MW contract is for firm service and the 400 MW contract has a priority higher than non-firm service but less than firm service. These elections obligate PSE&G to pay congestion costs associated with the daily elected level of service under the 600 MW contract and obligate Con Edison to pay congestion costs associated with the daily elected level of service under the 400 MW contract. The interface prices for this transaction are not defined PJM interface prices, but are defined in the protocol based on the actual facilities governed by the protocol.

Under the FERC order, PSE&G is assigned FTRs associated with the 600 MW contract. The PSE&G FTRs are treated like all other FTRs. In 2007, PSE&G's FTR revenues were equal to its congestion charges. (Revenues were $0.4 million less than charges in 2006.) Under the FERC order, Con Edison receives credits on an hourly basis for its elections under the 400 MW contract from a pool containing any excess congestion revenue after hourly FTRs are funded. In 2007, Con Edison's congestion credits equaled its day-ahead congestion charges. However, Con Edison had substantial negative day-ahead congestion charges with the result that Con Edison's total credits exceeded its congestion charges by approximately $1.7 million. (Credits had been $0.7 million less than charges in 2006.) (See Table 4-11.)

22 111 FERC ¶ 61,228 (2005).

23 Protest of the Consolidated Edison Company of New York, Inc., Protest, Docket No. EL02-23 (January 30, 2006).

24 FERC Order Denying Rehearing, Order, Docket No. EL02-23 (August 15, 2007).

In effect, Con Edison has been given congestion credits that are the equivalent of a class of FTRs covering positive congestion with subordinated rights to revenue. However, Con Edison is not treated as having an FTR when congestion is negative. An FTR holder in that position would pay the negative congestion credits, but Con Edison does not. The protocol's provisions about congestion payments clearly cover congestion charges and offsetting congestion credits, but are not explicit on the treatment of Con Edison's negative congestion credits, which were about $1.7 million in 2007. The parties should address this issue.

Table 4-11 Con Edison and PSE&G wheeling settlement data: Calendar year 2007

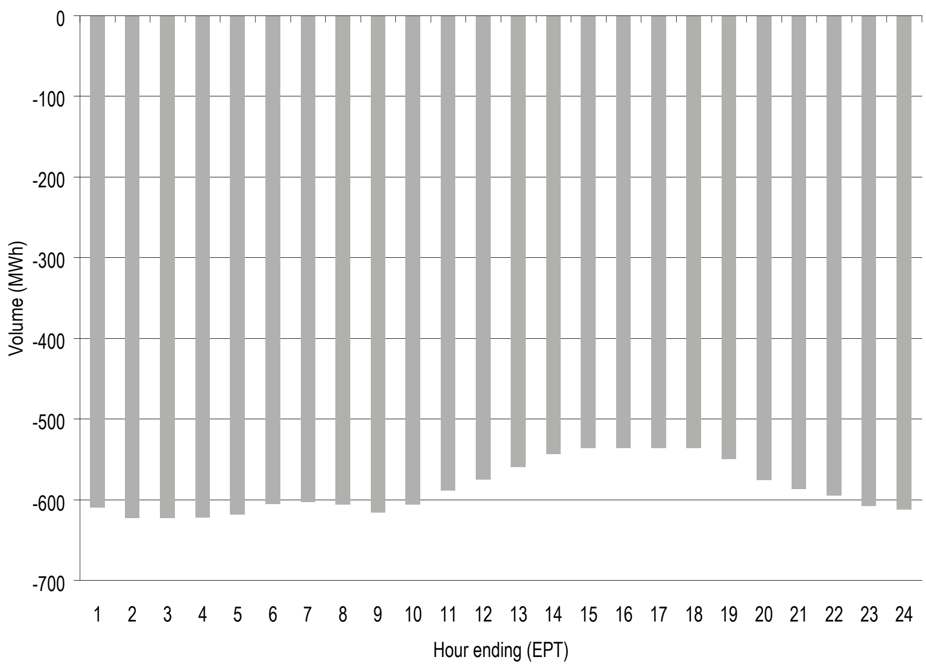
		Con Edison			PSE&G		
		Day Ahead	Balancing	Total	Day Ahead	Balancing	Total
Total	Congestion charge	$1,245,646.52	($463,565.37)	$782,081.15	$2,040,446.98	$0.00	$2,040,446.98
	Congestion credit			$2,320,742.14			$2,040,446.98
	Adj.			$119,684.99			($479.36)
	Net charge			($1,658,345.98)			$479.36

Under the terms of the protocol, Con Edison can make a real-time election of its desired flow for each hour in the Real-Time Energy Market. If this election differs from its day-ahead schedule, the company is subject to the resultant charges or credits. This occurred in 13 percent of the hours in 2007.

Neptune Underwater Transmission Line to Long Island, New York

On July 1, 2007, a 65-mile, DC transmission line from Sayreville, New Jersey, to Nassau County on Long Island via undersea and underground cable was placed in service. This is a merchant 230 kV transmission line with a capacity of 660 MW. The line is bi-directional, but in 2007, with the exception of testing, power flows were only from PJM to New York. Power is exported directly from New Jersey to Long Island. For 2007, the total real-time scheduled net exports on the Neptune line were 2,814 GWh while the day-ahead scheduled net exports were 2,790 GWh. (See Table 4-1 through Table 4-6.) Figure 4-14 shows the hourly average flow, by hour of the day, on the Neptune line for the period July through December 2007. The average hourly flow for the period July through December was -599 MWh. For the time period July through December, the average hourly PJM/NEPT Interface price was $76.29 per MWh, while in NYISO the Long Island zone's average price was $80.64 per MWh.

Figure 4-14 Neptune hourly average flow: July to December 2007



Interchange Transaction Issues

Four issues are associated with interchange transactions that require more detailed discussion: loop flows, ramp reservation rules, spot import service rules and up-to congestion transactions.

Loop Flows

Actual flows are the metered flows at an interface for a defined period. Scheduled flows are the flows scheduled at an interface for a defined period. Inadvertent interchange is the difference between the total actual flows for the PJM system (net actual interchange) and the total scheduled flows for the PJM system (net scheduled interchange) for a defined period. Loop flows are measured as the difference between actual and scheduled flows at one or more specific interfaces. Loop flows can exist at the same time that inadvertent interchange is zero. For example, actual imports could exceed scheduled imports at one interface and actual exports could exceed scheduled exports at another interface. The result is loop flow despite the fact that system actual and scheduled flow could net to a zero difference.

Loop flow can arise from transactions scheduled into, out of or around the PJM system on contract paths that do not correspond to the actual physical paths on which energy flows. Outside of LMP-based energy markets, energy is scheduled and paid for based on contract path, without regard to the path of the actual energy flows. Loop flows can also exist as a result of transactions within a market-based area in the absence of an explicit agreement to price congestion. Loop flows exist because electricity flows on the path of least resistance regardless of the path specified by contractual agreement or regulatory prescription. PJM manages loop flow using a combination of interface price signals, redispatch and TLR procedures.

Loop flows, measured as the differences between scheduled and actual flows at specific interfaces, are a significant concern. Loop flows have negative impacts on the efficiency of markets 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 also have poorly understood impacts on non market areas. In general, the detailed sources of the identified differences between scheduled and actual flows remain unclear.

The fact that total PJM net actual interface flows were very close to net scheduled interface flows on average for 2007 as a whole is not a useful measure of loop flow. There were significant differences between scheduled and actual flows for specific individual interfaces. (See Table 4-12.) From an operating perspective, PJM tries to balance overall actual and scheduled interchange, but does not have a mechanism to control the balance between actual and scheduled interchange at individual interfaces because there are free flowing ties with contiguous control areas.

During 2007, for PJM as a whole, net scheduled and actual interchange differed by less than 0.5 percent.[25] (See Table 4-12.) Actual system exports were 14,766 GWh, 63 GWh less than the scheduled total exports of 14,829 GWh. Flow balance varied at each individual interface. The PJM/MECS Interface was the most imbalanced, with net actual exports of 12,414 GWh exceeding scheduled exports of 1,610 GWh by 10,804 GWh or 671 percent, for an average of 1,233 MW during each hour of the year. At the PJM/TVA Interface, net actual flow was in the import direction at 924 GWh while scheduled flow was in the export direction at 4,938 GWh. The net difference was 5,862 GWh or -119 percent. At the PJM/CPLE Interface, net actual imports exceeded scheduled imports by 6,557 GWh or 858 percent. At the PJM/DUK Interface, net scheduled imports exceeded actual exports by 5,828 GWh or -203 percent. At the PJM/NYIS Interface, net actual exports exceeded scheduled exports by 5,279 GWh or 239 percent.

25 Net scheduled volumes include dynamic schedules. These are scheduled flows from generating units that are physically located in one control area but deliver power to another control area. The power from these units flows over the lines on which the actual flow at PJM's borders is measured. Since the dynamic schedules are included in the actual flows, they must be included in the scheduled flows in order to accurately compare actual to scheduled flows. Dynamic flows are included in the "Net Scheduled" column of Table 4-12. As a result, the total "Net Scheduled" in Table 4-12 does not match the total net interchange in Table 4-1. The difference of 569 GWh is the net dynamic schedule.

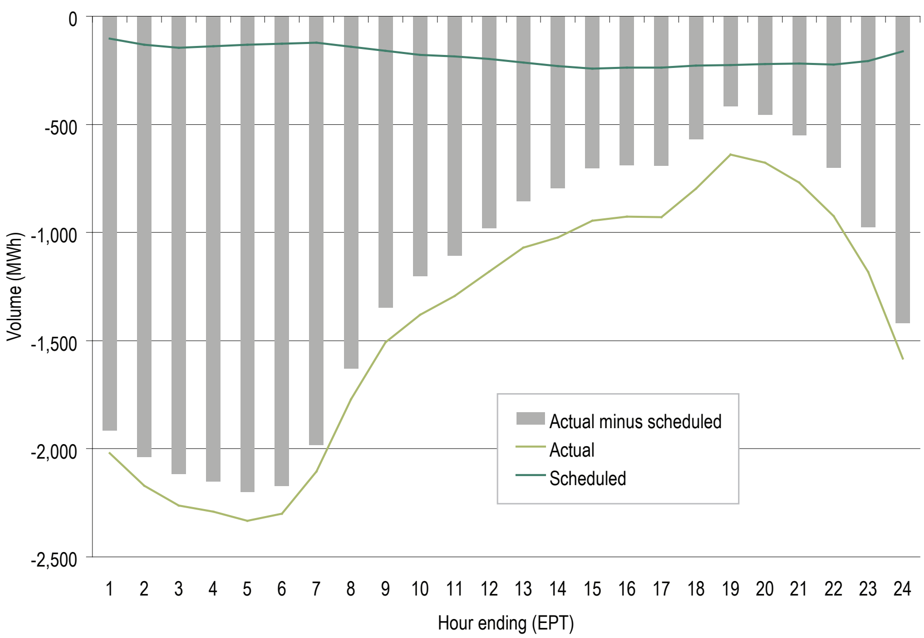
Table 4-12 Net scheduled and actual PJM interface flows (GWh): Calendar year 2007

	Actual	Net Scheduled	Difference (GWh)	Difference (Percent of Net Scheduled)
ALTE	(6,827)	(1,856)	(4,971)	268%
ALTW	(3,015)	(1,843)	(1,172)	64%
AMIL	4,791	(511)	5,302	(1038%)
AMRN	26	(134)	160	(119%)
CILC	181	(31)	212	(684%)
CIN	431	(2,607)	3,038	(117%)
CPLE	7,321	764	6,557	858%
CPLW	(1,881)	(704)	(1,177)	167%
CWLP	(617)	(155)	(462)	298%
DUK	(2,961)	2,867	(5,828)	(203%)
EKPC	183	(625)	808	(129%)
FE	2,356	(1,786)	4,142	(232%)
IP	616	11	605	5500%
IPL	3,803	(937)	4,740	(506%)
LGEE	1,087	344	743	216%
MEC	(4,726)	(3,228)	(1,498)	46%
MECS	(12,414)	(1,610)	(10,804)	671%
NEPT	(2,739)	(2,740)	1	(0%)
NIPS	(2,609)	(584)	(2,025)	347%
NYIS	(7,486)	(2,207)	(5,279)	239%
OVEC	9,212	8,823	389	4%
TVA	924	(4,938)	5,862	(119%)
WEC	(422)	(1,142)	720	(63%)
Total	(14,766)	(14,829)	63	(0.4%)

Loop Flows at the PJM/MECS and PJM/TVA Interfaces

As in 2006, the PJM/MECS Interface continued to exhibit large imbalances between scheduled and actual power flows, particularly during the overnight hours (hour ending 2400 through hour ending 0700). (See Figure 4-15.) Generally, the PJM/MECS Interface is an exporting interface meaning that power flows from PJM to MECS. The actual exports exceeded the scheduled exports at that interface by an average of 2,000 MW per hour for those overnight hours. The daytime hours (hour ending 0800 through hour ending 2300) difference between actual and scheduled exports averaged 855 MW.

Figure 4-15 PJM/MECS Interface average actual minus scheduled volume: Calendar year 2007



While the PJM/TVA Interface also exhibited large mismatches between scheduled and actual power flows, the magnitude of the mismatches declined after consolidation. 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. (See Figure 4-16 and Figure 4-17.) The consolidation of the former southeast and southwest pricing points in October 2006 has had an ongoing impact at the PJM/TVA Interface.[26] Figure 4-16 shows the average hourly actual, scheduled flows and the difference between them for the preconsolidation time period January 1, 2006, through September 30, 2006. Actual exports were less than scheduled exports by 1,328 MWh every hour, on average during nine-month preconsolidation period. During calendar year 2007, this difference decreased by 50 percent to 670 MW (on average) each hour. (See Figure 4-17.)

26 For a more detailed discussion of this issue, see the *2006 State of the Market Report*, Volume II, Section 4, "Interchange Transactions," at "Loop Flows at PJM's Southern Interfaces."

Figure 4-16 PJM/TVA average flows: January 1, to September 30, 2006, preconsolidation

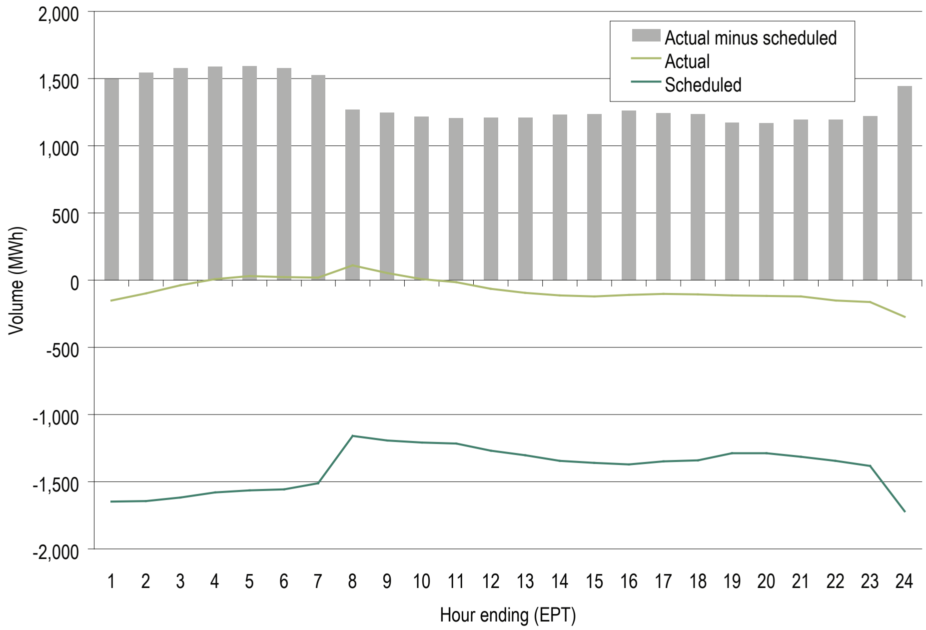
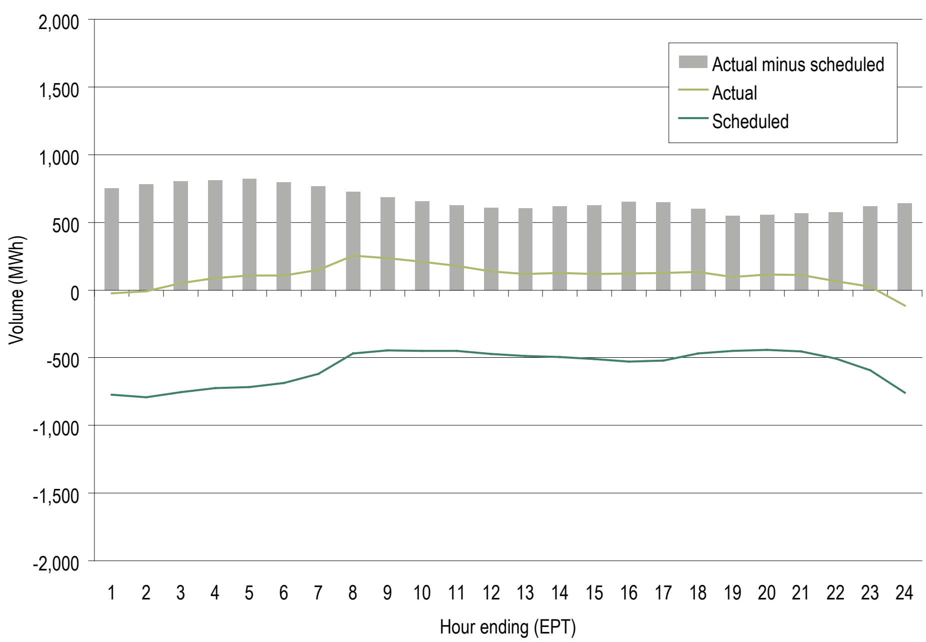


Figure 4-17 PJM/TVA average flows: Calendar year 2007



Loop Flows at PJM's Southern Interfaces

Figure 4-18 and Figure 4-19 illustrate the reduction in the previously persistent difference between scheduled and actual power flows at PJM's southern interfaces (PJM/TVA and PJM/EKPC to the west and PJM/CPLE, PJM/CPLW and PJM/DUK to the east) that grew to its largest volumes through the summer of 2006. One reason for this improvement was the consolidation of the former southeast and southwest pricing points into the SOUTHEXP and SOUTHIMP pricing points. In order to reflect the actual flow of transactions associated with the southeast and southwest interface pricing points, on October 1, 2006, PJM began to price all transactions that source in PJM and sink in one of the relevant, defined control areas, at the SOUTHEXP interface pricing point. Similarly, PJM began to price all transactions that sink in PJM and source in one of the defined control areas, at the SOUTHIMP interface pricing point. This practice enabled PJM to price imports and exports differently based on their impacts on the PJM transmission system.

Figure 4-18 Southwest actual and scheduled flows: Calendar years 2006 to 2007

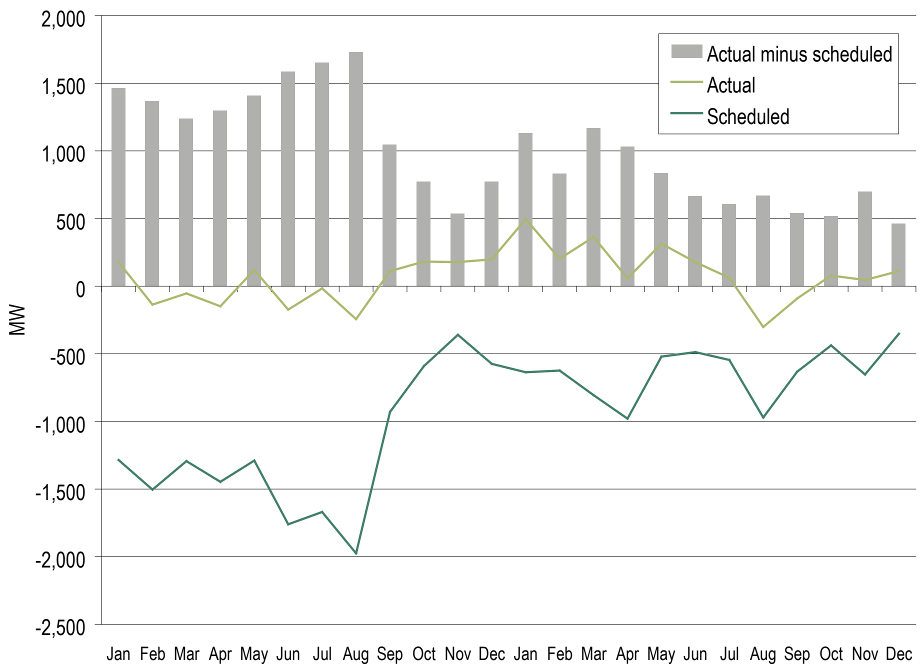
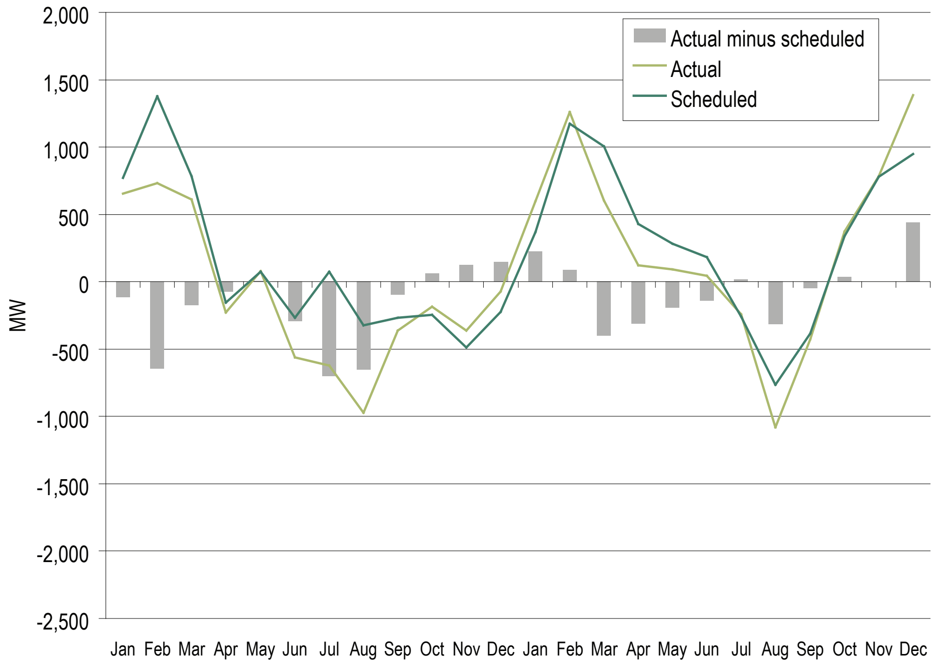


Figure 4-19 Southeast actual and scheduled flows: Calendar years 2006 to 2007



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 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 term non market area is a misnomer in the sense that all electricity transactions are part of the broad energy market in the Eastern Interconnection. There are areas with transparent markets and there are areas with less transparent markets, but these areas together comprise a market and overall market efficiency would benefit from the increased transparency that would derive from a better understanding of loop flow.

PJM and Midwest ISO issued a joint loop flow report in 2007 that made three recommendations including the establishment of an energy schedule tag archive.[27] The archive would capture and retain data for the entire Eastern Interconnection including tag impact, generation-to-load impact and market flow impact data for flowgates in the IDC. The archive would be a prime source of information needed to perform after-the-fact analyses and reviews. This effort should be given a high priority.

27 See "Investigation of Loop Flows Across Combined Midwest ISO AND PJM Footprint" (May 25, 2007) (Accessed February 15, 2008) <http://www.jointandcommon.com/working-groups/joint-and-common/downloads/20070525-loop-flow-investigation-report.pdf> (2,597 KB).

PJM and Midwest ISO also submitted a memorandum to a NAESB committee reiterating and elaborating the recommendation regarding data retention and suggesting a process for determining the allocation of responsibility for congestion relief.[28] The NAESB committee included in their annual plan a commitment to work with NERC on the congestion management issue.[29]

Ramp Reservation Issues

PJM limits the amount of change in net interchange within 15-minute intervals in order to ensure compliance with NERC performance standards. Changes in net interchange affect PJM operations and markets as they require increases or decreases in generation to meet load. The change in net interchange is referred to as ramp. Any market participant wishing to initiate (or to change) a transaction must obtain a ramp reservation. PJM issues reservations, on a first-come, first-served basis, up to the ramp limit.

While ramp limits may be modified by PJM depending on system conditions, the limit is generally ± 1,000 MW within a 15-minute interval. For example, if at 0800 Eastern Prevailing Time (EPT) the sum of all external transactions were -3,000 MW (negative sign indicates net exporting), the limit for 0815 would be -2,000 MW to -4,000 MW. In other words, the starting or ending of transactions would be limited so that the overall change from the previous 15-minute period would not exceed 1,000 MW in either direction.

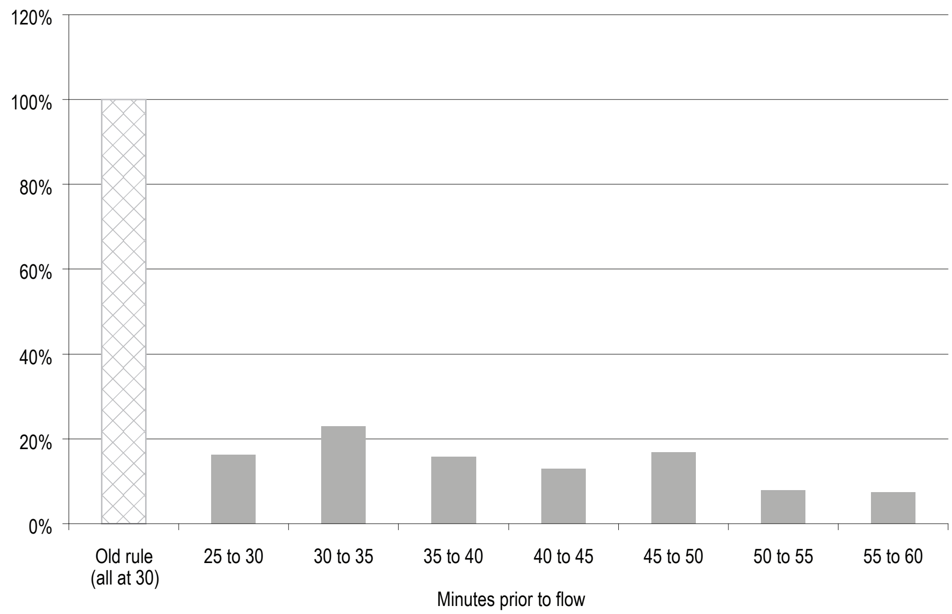
Figure 4-20 shows the ongoing results of the ramp rule change that became effective on August 7, 2006.[30] Under the new rule, unused ramp reservations expire at the conclusion of a defined time interval that starts when a reservation is approved. The goal was to prevent large swings in ramp at 30 minutes prior to flow and to spread automatic ramp reservation expirations over a longer period to permit other participants to use them. The actual distribution pattern of expirations since the rule change is compared to when reservations would have expired under the old rule in Figure 4-20. Under the old rule, all unused reservations had expired at the same time, 30 minutes prior to flow or just 10 minutes prior to the deadline for scheduling a transaction (20 minutes prior to flow).

28 See "Annual Plan Item: Determine Future Path for TLR in Concert with NERC" (October 24, 2007) (Accessed January 29, 2008) <http://www.naesb.org/pdf3/weq_aplan102907w1.pdf> (26 KB).

29 See "North American Energy Standards Board, 2008 WEQ Annual Plan Adopted by the Board of Directors on December 13, 2007" (December 13, 2007) (Accessed January 29, 2008) <http://www.naesb.org/pdf3/weq_2008_annual_plan.doc> (281 KB).

30 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. (See the *2006 State of the Market Report*.)

Figure 4-20 Distribution of expired ramp reservations in the hour prior to flow (Old rules (Theoretical) and new rules (Actual)): October 2006 to December 2007



While the rule change has had a positive effect, the MMU continues to monitor the reservation and use of ramp. In the *2006 State of the Market Report,* the MMU indicated that the artificial creation of ramp room was another issue that needed to be addressed. For example, a market participant who wishes to initiate an import transaction when there is no available import ramp, requests a ramp reservation in the exporting direction. When accepted, this reservation creates apparent import ramp which permits the participant to obtain an import reservation. Ultimately, the import transaction would flow and the export reservation would not be used to export energy, expiring after its time limit. In 2007, PJM modified its business rules to permit PJM to cut such a participant's transaction(s) prior to using the normal, last-in-first-out method of ordering cuts, if PJM determines that a participant has scheduled an offsetting reservation that is unused.[31] Although the rule has been added, the mechanism for automatically performing this task has not yet been developed. System operators may apply this rule manually.

During 2007 a ramp-related issue emerged associated with transactions into and out of New York. Large swings in PJM's New York ramp availability have been regularly observed at the New York interface. The NYISO rules for its hourly market require transaction bids to be placed at least 75 minutes prior to flow. For each potential import or export transaction that is bid into the NYISO market, a PJM ramp reservation is required. During the time between the bid submission to NYISO and the time the NYISO market results are posted, all ramp reservations associated with all the bids are in PJM's system, often leaving no ramp available, awaiting the outcome of the NYISO market clearing. When the NYISO market results are posted, the ramp reservations for any unsuccessful bids are returned to the PJM system. This results in the large

31 PJM. "Manual 41: Managing Interchange," Revision 01 (September 5, 2007), p. 9.

swing in ramp observed at about 20 minutes after the hour. The difference between transaction rules in NYISO and PJM create incentives to obtain ramp that will not be needed. There is also the potential for gaming in that out-of-market bids and offers for import or export transactions to the NYISO could be used to limit ramp availability to competitors. Both areas should be addressed.

Spot Import Service

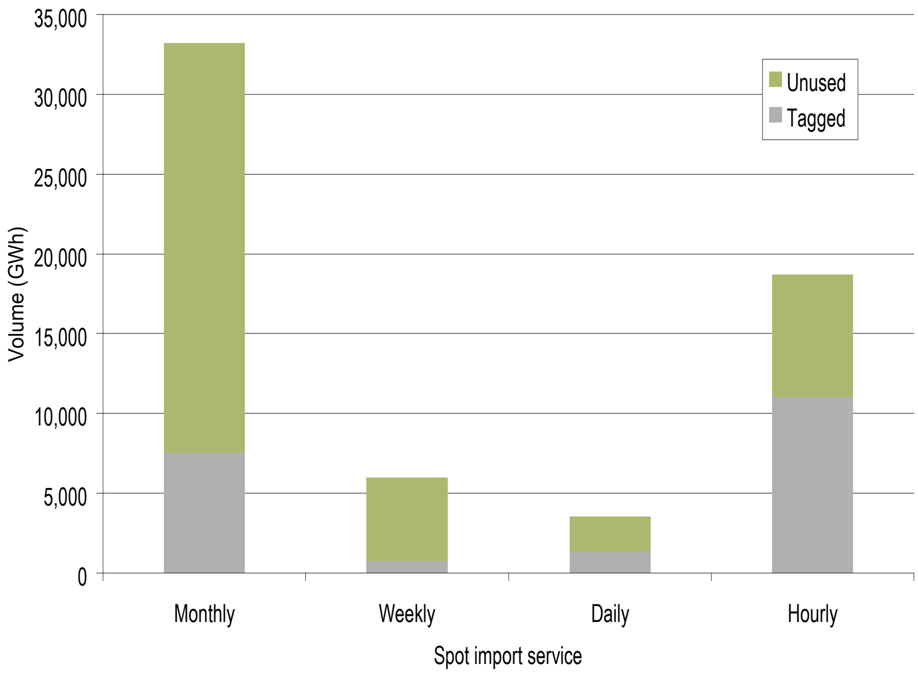
A new interchange transaction issue emerged in 2007. Some participants obtain and hold large amounts of spot import service reservations without using the service. Prior to April 2007, PJM did not limit spot import service, preferring to let market prices ration the use of the service which is not physically limited. PJM interpreted its JOA with the Midwest ISO to require a limitation on spot import service in order to limit the impact of such transactions on selected external flowgates.[32] The rule caused the availability of spot import service to be limited by ATC on the transmission path.

The four spot import reservation types are: monthly, weekly, daily and hourly. Figure 4-21 shows the utilization of the four spot import service products for May through December 2007, the period when PJM's new rule regarding the reservation of spot import service was in place. Most of the spot import reservations were for monthly service and most monthly reservations were not used. Only 23 percent of the reserved volume was used on NERC tags. The hourly service was the most utilized with 59 percent of the reserved volume used on NERC tags.

Following implementation of the rule, participants have complained that they are not able to obtain this service. There are a number of options for addressing the issue including making reservations available only hourly or daily or requiring reservation holders to release reservations if they will not be used within a defined lead time.

32 See "Modifications to the Practices for Non-Firm and Spot Market Import Service" (April 20, 2007) (Accessed February 7, 2008) <http://www.pjm.com/etools/oasis/downloads/wpc-white-paper.pdf > (97 KB).

Figure 4-21 Spot import service utilization: May through December 2007



Up-to Congestion Transactions

Up-to congestion transactions are Day-Ahead Market transactions for which a participant can specify the maximum level of positive congestion cost that they are willing to pay, up to a cap of $25 per MWh.[33]

There is a mismatch between up-to congestion transactions in the Day-Ahead Energy Market and the Real-Time Energy Market.[34] In the Day-Ahead Energy Market, an up-to congestion import transaction is submitted and modeled as an injection at the interface and a withdrawal at a specific PJM node. In real time, the power does not flow to the PJM node specified in the day-ahead transaction. This mismatch results in inaccurate pricing and can provide a gaming opportunity.[35]

33 See "External Interchange Transaction Issue" (June 27, 2007), pp. 10-11 (Accessed February 20, 2008) <http://www.pjm.com/committees/mic/downloads/20070627-item-05-transaction-issue.pdf> (298 KB).

34 See "Up-to Congestion Transactions: Proposed Interim Changes Pending Development of a Spread Product" (December 13, 2007) (Accessed February 13, 2008) <http://www.pjm.com/committees/mic/downloads/20080130-item-03b-up-to-congestion-transactions.pdf> (34 KB).

35 See "Proposed Elimination of Up To Source Sinks" (December 13, 2007) (Accessed February 13, 2008) <http://www.pjm.com/committees/mic/downloads/20080130-item-03b-proposed-elimination-of-up-to-source-sinks.xls> (111 KB).

SECTION 5 – CAPACITY MARKET

Effective June 1, 2007, the PJM Capacity Credit Market (CCM), which had been the market design since 1999, was replaced with the RPM Capacity Market construct. For the *2007 State of the Market Report,* the Market Monitoring Unit (MMU) analyzed the market structure, participant conduct and market performance of both Capacity Market designs and compared the 2007 market results to 2006 and certain other prior years.[1]

Each organization serving PJM load must pay for the capacity resources required to meet its capacity obligations. Collectively, all arrangements by which load-serving entities (LSEs) acquire capacity are known as the Capacity Market.[2] Under the CCM, LSEs could acquire capacity resources by relying on the PJM Capacity Market, by constructing generation, or by entering into bilateral agreements. Under RPM, LSEs must pay the locational capacity price for their zone. LSEs can own capacity or purchase capacity bilaterally and can offer capacity into the RPM Auctions.

Overview

The MMU analyzed market structure and market performance in the PJM Capacity Market for calendar year 2007, including supply, demand, concentration ratios, pivotal suppliers, volumes, prices, outage rates and reliability. The analyses of the two market designs are presented separately, but there is substantial overlap in the basic elements of the Capacity Markets.

Capacity Credit Market

Market Design

The PJM CCM provided mechanisms to balance the supply of and demand for capacity unmet by the bilateral market or self-supply.[3] The CCM consisted of the Daily, Interval, Monthly and Multimonthly CCM.[4] The CCM was 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 Daily CCM permitted LSEs to match capacity resources with short-term shifts in retail load while the Interval, Monthly and Multimonthly CCMs provided mechanisms to match longer-term obligations to serve load with capacity resources.

Market Structure

- Supply. Unforced capacity remained relatively constant in the CCM in January through May 2007 compared to 2006.[5] Average unforced capacity increased by 377 MW or 0.2 percent to 152,859 MW.[6]

1 During calendar years 2004 and 2005, PJM conducted the phased integration of five control zones: ComEd, American Electric Power (AEP), The Dayton Power & Light Company (DAY), Duquesne Light Company (DLCO) and Dominion. By convention, control zones bear the name of a large utility service provider working within their boundaries. The nomenclature applies to the geographic area, not to any single company. For additional information on the integrations, their timing and their impact on the footprint of the PJM service territory, see the *2007 State of the Market Report*, Volume II, Appendix A, "PJM Geography." For additional information on the phased integration into the PJM CCM of the ComEd Control Zone, see the *2006 State of the Market Report*, Volume II, Appendix E, "Capacity Market."

2 See the *2007 State of the Market Report*, Volume II, Appendix M, "Glossary" and Appendix N, "Acronyms" for definitions of PJM Capacity Market terms.

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

4 PJM defined three intervals for its CCM. The first interval extended for five months and ran from January through May. The second interval extended for four months and ran from June through September. The third interval extended for three months and ran from October through December.

5 For information on the CCM during 2006, see the *2006 State of the Market Report*, Volume II, Section 5, "Capacity Market."

6 Calculated values shown in Section 5, "Capacity Market," are based on unrounded, underlying data and may differ from calculations based on the rounded values shown in tables.

Capacity resources exceeded capacity obligations every day by an average of 9,450 MW, a decrease of 81 MW from the average net excess of 9,531 MW for 2006.

- Demand. Unforced obligations also remained relatively constant in the PJM CCM in January through May 2007 compared to 2006. Average load obligations increased by 458 MW or 0.3 percent to 143,409 MW. PJM electricity distribution companies (EDCs) and their affiliates maintained an 80.8 percent market share of load obligations in the PJM CCM in January through May 2007, down from 87.6 percent for 2006.

- Market Concentration. Structural analysis of the PJM Capacity Market during the January through May period found significant market structure issues both in the CCM and the overall ownership of capacity. All daily auctions failed the three pivotal supplier (TPS) test; 97.4 percent of daily auctions failed the single pivotal supplier test and 83.3 percent of monthly auctions failed the single pivotal supplier test. Total capacity ownership also failed the single pivotal supplier test throughout the period, with three individual suppliers who were each pivotal on a stand-alone basis.

- Imports and Exports. In January through May 2007, imports averaged 2,794 MW, which was a decrease of 299 MW or 9.7 percent from the 2006 average of 3,093 MW. Exports averaged 4,939 MW, which was a decrease of 19 MW or 0.4 percent from the 2006 average of 4,958 MW. Average net exchange increased by 280 MW or 15.0 percent to -2,145 MW from the 2006 average of -1,865 MW. Internal bilateral transactions averaged 163,009 MW, which was an increase of 2,057 MW or 1.3 percent from the 160,952 MW average for 2006.

- Active Load Management (ALM). In January through May 2007, ALM credits in the PJM CCM averaged 1,677 MW, down 151 MW (8.3 percent) from 1,828 MW in 2006.

Market Performance

- CCM Prices and Volumes. During January through May 2007, total PJM CCM prices averaged $3.21 per MW-day, which was $2.52 per MW-day less than the 2006 average of $5.73 per MW-day. Total PJM CCM transactions averaged 11,727 MW (8.2 percent of obligation), 2,609 MW higher than the 2006 average of 9,118 MW (6.4 percent of obligation).

  For calendar year 2006, capacity resources across the entire regional transmission organization (RTO) were valued at a total of $299.0 million. This equals the total capacity obligation valued at the combined-market, weighted-average CCM clearing price for 2006.

RPM Capacity Market

Market Design

On June 1, 2007, the RPM Capacity Market design was implemented in the PJM region, replacing the CCM Capacity Market design that had been in place since 1999.[7] The RPM market design differs from the CCM market design in a number of important ways. The RPM is a forward-looking, annual, locational market, with a must-offer requirement for capacity and mandatory participation by load, with performance incentives for generation, that includes clear, market power mitigation rules and that permits the direct participation of demand-side resources. CCM, in contrast, was a daily, single-price, voluntary balancing market that included less than 10 percent of total PJM capacity, that had weak performance incentives, that had no explicit market power mitigation rules and that did not permit the participation of demand-side resources.

Under RPM, capacity obligations are annual. Under CCM, capacity obligations were daily. Under RPM, auctions are held for delivery years that are three years in the future. Under CCM daily, monthly and multimonthly auctions were held. Under RPM, prices are locational and may vary depending on transmission constraints.[8] Under CCM, prices were the same, regardless of location. Under RPM, sell offers are unit-specific. Under CCM, offers were non-unit-specific capacity credits. Under RPM, existing generation capable of qualifying as a capacity resource must be offered into RPM Auctions, except for the fixed resource requirement (FRR) option. Under CCM, there was no must-offer rule after June 2000. Under RPM, participation by LSEs is mandatory, except for the FRR option. Under CCM, there was no mandatory participation in the CCM auctions.[9] Under RPM, there is an administratively determined demand curve that defines scarcity pricing levels and that, with the supply curve derived from capacity offers, determines market prices. Under CCM the demand was defined by participant buy bids. Under RPM there are performance incentives for generation. Under CCM the only performance incentive was the direct relationship between historical equivalent demand forced outage rate (EFORd) and the amount of capacity that could be sold. Under RPM there are explicit market power mitigation rules that define structural market power, that define offer caps based on the marginal cost of capacity and that do not limit prices offered by new entrants. Under CCM, there were no explicit market power mitigation rules. Under RPM, demand-side resources may be offered directly into the auctions and receive the clearing price. Under CCM, demand-side resources could not be offered directly into the market.

Market Structure

- Supply. Total internal capacity increased from 154,985.5 MW on January 1, 2007, to 155,206.0 MW on June 1, 2007, or 220.5 MW. This increase was the result of 573.2 MW from demand response (DR) offered into the auction, offset in part by 332.6 MW from higher EFORds and 20.1 MW from generation deratings. No new generation was offered into the 2007/2008 RPM Auction.

7 The terms *PJM Region*, *RTO Region* and *RTO* are synonymous in the *2007 State of the Market Report*, Volume II, Section 5, "Capacity Market" and include all capacity within the PJM footprint.

8 Transmission constraints are local capacity import capability limitations (low capacity emergency transfer limit (CETL) margin over capacity emergency transfer objective (CETO)) caused by transmission facility limitations, voltage limitations or stability limitations.

9 See "Reliability Assurance Agreement among Load-Serving Entities in the PJM Region," Schedule 8.1 (June 1, 2007) (Accessed July 19, 2007) <http://www.pjm.com/documents/downloads/agreements/raa.pdf> (1.92 MB).

In the 2008/2009 and 2009/2010 auctions, new generation increased 528.6 MW; 112.6 MW were brought out of retirement and net generation uprates were 220.3 MW, for a total of 861.5 MW. DR offers increased 815.9 MW through June 1, 2009. Net improvements in EFORds added 434.8 MW. The net effect from May 31, 2007, through June 1, 2009, was an increase in total internal capacity of 2,350.6 MW (1.5 percent) from 154,967.6 MW to 157,318.2 MW.

In the 2008/2009 auction, 15 more generating units made offers than in the 2007/2008 RPM Auction. The increase included five new wind units (66.1 MW), three new diesel units (23.3 MW) and two units (112.6 MW) which came out of retirement while the remaining five units were the result of a reclassification of external units.

In the 2009/2010 auction, 17 more generating units made offers than in the 2008/2009 RPM Auction. The increase included eight new combustion turbine (CT) units (380.2 MW), two new diesel units (9.2 MW) and one new steam unit (49.8 MW) while the remaining six units included more units imported, fewer units exported, a decrease in units excused from offering into the auction and fewer units removed from the auction under the fixed resource requirement (FRR) option.

- Demand. There was a 5,298.6 MW increase in the RPM reliability requirement, which is similar to the obligation under CCM, from 142,978.7 MW on January 1, 2007, to 148,277.3 MW on June 1, 2007. On June 1, 2007, PJM EDCs and their affiliates maintained a 77.5 percent market share of load obligations under RPM, down from an average of 80.8 percent for the first five months of 2007 under CCM.

- Market Concentration. For the 2007/2008, 2008/2009 and 2009/2010 RPM Auctions, all defined markets failed the preliminary market structure screen (PMSS). In each auction all participants in the total PJM market as well as the locational deliverability area (LDA) markets failed the three pivotal supplier (TPS) market structure test. The result was that offer caps were applied to all sell offers in all three auctions.

- Imports and Exports. Net exchange, which is imports less exports, decreased 707.6 MW from January 1, to June 1, 2007, as the result of a decrease in exports of 682.9 MW and an increase in imports of 24.7 MW.

- Demand-Side Resources. Under RPM, demand-side resources in the Capacity Market, a combination of DR offered into the RPM Auctions and certified/forecast interruptible load for reliability (ILR), increased from the 1,676.7 MW in the CCM ALM program by 87.2 MW on June 1, 2007, by an additional 882.2 MW on June 1, 2008, and an additional 354.3 MW on June 1, 2009. The ALM volumes were MW credits against the obligation while the LM volumes are treated as capacity resources.

- Net Excess. Net excess as calculated under CCM decreased 4,370.5 MW from 10,169.9 MW on January 1, to 5,799.4 MW on June 1, 2007. Net excess as calculated under RPM was 5,240.5 MW or 558.9 MW less than the 5,799.4 MW as calculated under CCM on June 1, 2007.

Market Conduct

- 2007/2008 RPM Auction. Of the 1,061 generating units which submitted offers, unit-specific offer caps were calculated for 125 units (11.8 percent). Offer caps of all kinds were used by 566 units (53.4 percent), of which 388 were the default (proxy) offer caps calculated and posted by the MMU. The remaining 495 units were price takers, of which the offers for 492 units were zero and the offers for three units were set to zero because no data were submitted. Fifteen DR resources offered into the auction.

- 2008/2009 RPM Auction. Of the 1,076 generating units which submitted offers, unit-specific offer caps were calculated for 117 units (10.9 percent). Offer caps of all kinds were used by 567 units (52.7 percent), of which 399 were the default (proxy) offer caps calculated and posted by the MMU.

- 2009/2010 RPM Auction. Of the 1,093 generating units which submitted offers, unit-specific offer caps were calculated for 151 units (13.8 percent). Offer caps of all kinds were used by 550 units (50.3 percent), of which 377 were the default (proxy) offer caps calculated and posted by the MMU.

Market Performance

2007/2008 RPM Auction

- RTO. Total internal RTO unforced capacity of 155,206.0 MW includes all generating units and DR that qualified as a PJM capacity resource for the 2007/2008 RPM Auction, excludes external units and reflects owners' modifications to installed capacity (ICAP) ratings. Including FRR, committed resources and imports, RPM capacity was 135,092.6 MW. The 129,409.2 MW of cleared resources for the entire RTO represented a reserve margin of 19.8 percent, which was 3,604.2 MW greater than the reliability requirement of 125,805.0 MW (installed reserve margin (IRM) of 15.0 percent) and resulted in a clearing price of $40.80 per MW-day.

  Total resources in the RTO were 129,409.2 MW which resulted in a net excess of 5,240.5 MW, a decrease of 3,693.6 MW from the net excess of 8,934.1 MW on May 31, 2007. Certified interruptible load for reliability (ILR) was 1,636.3 MW.

  Cleared resources across the entire RTO will receive a total of $4.3 billion based on the unforced MW cleared and the prices in the 2007/2008 RPM Auction.

- Eastern Mid-Atlantic Area Council (EMAAC). Total internal EMAAC unforced capacity of 30,825.1 MW includes all generating units and DR that qualified as a PJM capacity resource, excludes external units and reflects owners' modifications to ICAP ratings. Including imports into EMAAC, RPM unforced capacity was 30,841.0 MW. Of the 2,121.8 MW of incremental supply, 2,092.4 MW cleared, which resulted in a resource-clearing price of $197.67 per MW-day.

  Total resources in EMAAC were 36,642.8 MW, which when combined with certified ILR of 387.0 MW resulted in a net excess of -206.9 MW (0.6 percent) less than the reliability requirement of 37,236.7 MW.

- Southwestern Mid-Atlantic Area Council (SWMAAC). Total internal SWMAAC unforced capacity of 10,352.2 MW includes all generating units and DR that qualified as a PJM capacity resource, excludes external units and reflects owners' modifications to ICAP ratings. There were no imports from outside PJM into SWMAAC. All of the 650.1 MW of incremental supply cleared, resulting in a resource-clearing price of $188.54 per MW-day.

  Total resources in SWMAAC were 15,900.2 MW, which when combined with certified ILR of 273.4 MW resulted in a net excess of 98.3 MW (0.6 percent) greater than the reliability requirement of 16,075.3 MW.

Generator Performance

- Forced Outage Rates. From 2003 to 2004, the average PJM EFORd increased, from 6.7 percent in 2003 to 7.3 percent in 2004.[10] In 2005, the average PJM EFORd decreased to 6.6 percent, continued to decrease in 2006 to 6.4 percent and then increased to 6.9 percent in 2007. The increase in EFORd from 2006 to 2007 was the result of increased forced outage rates of combustion turbine and steam generating unit types. These forced outage rates are for the entire PJM Control Area.[11]

Conclusion

The RPM Capacity Market design was implemented effective June 1, 2007. RPM represents a significant change in the structure of the Capacity Market in PJM. The RPM is a forward-looking, annual, locational market, with a must-offer requirement for capacity and mandatory participation by load, with performance incentives for generation, that includes clear, market power mitigation rules and that permits the direct participation of demand-side resources.

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 CCM design as well as for the RPM. 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. 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. 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 and has market power.

In other words, the market design for capacity leads, almost unavoidably, to structural market power. 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

10 Annual EFORd data presented in state of the market reports may be revised based on final data submitted after the publication of the reports.

11 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.

and supplier knowledge of aggregate market demand, the MMU concludes that the potential for the exercise of market power continues to be high. Market power is and will remain endemic to the existing structure of the PJM Capacity Market. 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. 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 unlikely structural change that results in much more diversity of ownership.

The RPM Capacity Market design represents a significant advance over the previous CCM design in ensuring competitive outcomes 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 is consistent with the appropriate market design objectives of permitting competitive prices to reflect local scarcity conditions while explicitly limiting market power. The RPM Capacity Market design provides that competitive prices can reflect locational scarcity while not relying on the exercise of market power to achieve that design objective and limits the exercise of market power via the application of the three pivotal supplier test.

The introduction of the RPM design had a large impact on total capacity-related revenues. Under the CCM design, for calendar year 2006, capacity resources across the entire RTO were valued at a total of $299.0 million. Under the RPM, cleared capacity resources across the entire RTO, were valued at $4.3 billion under the 2007/2008 auction, an increase of approximately $4 billion.

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 were somewhat attenuated in the CCM design. The performance incentives are stronger in the RPM Capacity Market design although they need further strengthening. 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 and if they are successful, this will also result in lower forced outage rates. Well-designed scarcity pricing could also provide strong, complementary incentives for reduced outages during high-load periods. It would be preferable to rely on strong market-based incentives for capacity resource performance rather than the current structure of penalties, which has its own incentive effects.

The analysis of PJM 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.

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 under the CCM construct in 2007. Explicit market power mitigation rules in the RPM construct offset the underlying market structure issues in the PJM Capacity Market under RPM. The PJM Capacity Market results were competitive during 2007.

Capacity Credit Market

Market Design

The PJM CCM provided mechanisms to balance the supply of and demand for capacity unmet by the bilateral market or self-supply. The CCM consisted of the Daily, Interval, Monthly and Multimonthly CCM. The CCM was 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 Daily CCM permitted LSEs to match capacity resources with short-term shifts in retail load while the Interval, Monthly and Multimonthly CCMs provided mechanisms to match longer-term obligations to serve load with capacity resources.

Market Structure

The MMU analyzed the supply of and demand for capacity, market concentration in the PJM CCM and, for total capacity, internal and external bilateral capacity transactions and ALM activity.

Supply

System net excess capacity is a function of unforced capacity, capacity obligation, the sum of members' excesses and the sum of members' deficiencies. Unforced capacity includes capacity imports and exports. Net excess is the net pool position, calculated by subtracting total capacity obligation from total capacity resources. Since total capacity obligation includes expected total load plus a reserve margin, a pool net excess position of zero is consistent with established reliability objectives. Table 5-1 and Figure 5-1 present these data for January though May 2007.[12]

Under the CCM design, the capacity resources in PJM on any day reflected the addition of new resources, the retirement of old resources and the importing or exporting of capacity resources. These daily changes were a function of market forces. During January through May 2007, unforced capacity remained relatively constant in the PJM Capacity Market compared to 2006. Average unforced capacity increased by 377 MW from 152,482 MW to 152,859 MW, an increase of 0.2 percent. Capacity resources exceeded capacity obligations in PJM on every day and the daily average net excess was 9,450 MW (6.6 percent of average obligation), a decrease of 81 MW from the average net excess of 9,531 MW for 2006 (6.7 percent of average obligation).

12 These data were posted on a monthly basis at <http://www.pjm.com> under the PJM Market Monitoring Unit link.

Table 5-1 PJM capacity summary (MW): January through May 2007

	Mean	Standard Deviation	Minimum	Maximum
Installed capacity	162,401	332	161,994	162,841
Unforced capacity	152,859	221	152,468	153,149
Obligation	143,409	273	142,979	143,784
Sum of excess	9,450	408	8,931	10,170
Sum of deficiency	0	0	0	1
Net excess	9,450	408	8,930	10,170
Imports	2,794	20	2,785	2,839
Exports	4,939	221	4,621	5,302
Net exchange	(2,145)	225	(2,518)	(1,837)
Unit-specific transactions	15,495	216	15,358	15,961
Capacity credit transactions	147,514	2,694	144,134	152,028
Internal bilateral transactions	163,009	2,600	159,507	167,418
Daily capacity credits	3,458	189	3,057	3,893
Monthly capacity credits	2,252	362	1,860	2,881
Multimonthly capacity credits	6,017	364	5,375	6,325
All capacity credits	11,727	573	10,292	12,574
ALM credits	1,677	0	1,677	1,677

Figure 5-1 Capacity obligation for the PJM Capacity Market: January through May 2007

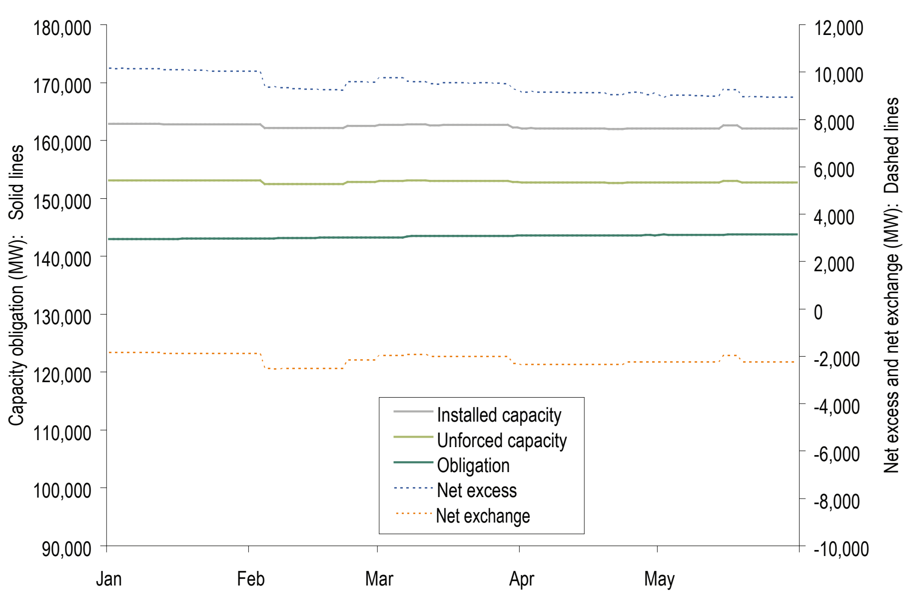
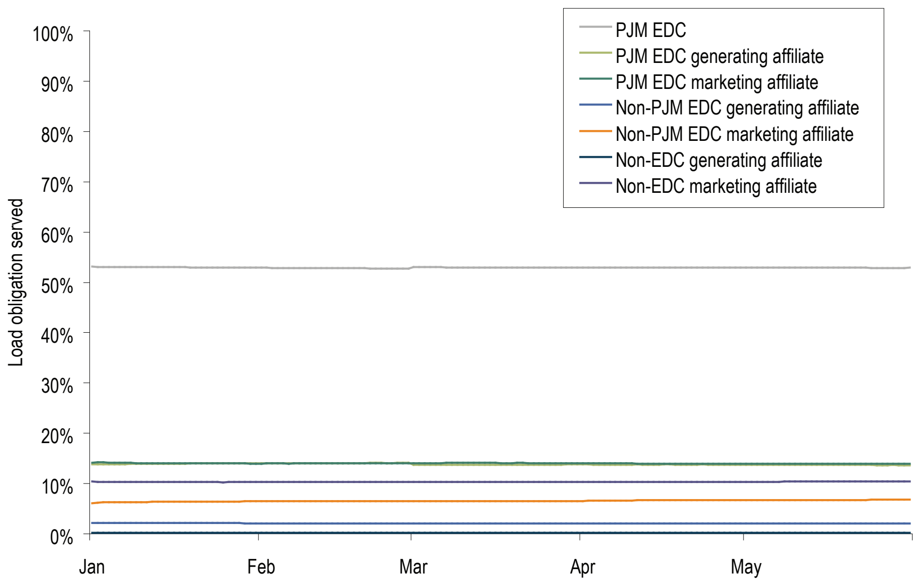


Figure 5-2 PJM Capacity Market load obligation served (Percent): January through May 2007



Demand

The total demand for capacity is the pool capacity obligation which is set annually via an administrative process. During January through May 2007, obligations remained relatively constant in the PJM Capacity Market compared to 2006. Average load obligations increased 458 MW or 0.3 percent from 142,951 MW to 143,409 MW.

The MMU analyzed market sectors in the PJM Capacity Market to determine how they met their load obligations. The Capacity Market was divided into the following sectors:

- PJM EDC. EDCs with a franchise service territory within the PJM footprint. This sector includes traditional utilities, electric cooperatives, municipalities and power agencies.
- PJM EDC Generating Affiliate. Affiliate companies of PJM EDCs that own generating resources.
- PJM EDC Marketing Affiliate. Affiliate companies of PJM EDCs that sell power and have load obligations in PJM, but do not own generating resources.
- Non-PJM EDC. EDCs with franchise service territories outside the PJM footprint.
- Non-PJM EDC Generating Affiliate. Affiliate companies of non-PJM EDCs that own generating resources.

- Non-PJM EDC Marketing Affiliate. Affiliate companies of non-PJM EDCs that sell power and have load obligations in PJM, but do not own generating resources.

- Non-EDC Generating Affiliate. Affiliate companies of non-EDCs that own generating resources.

- Non-EDC Marketing Affiliate. Affiliate companies of non-EDCs that sell power and have load obligations in PJM, but do not own generating resources.

During January through May 2007, PJM EDCs and their affiliates maintained a large market share of load obligations in the PJM Capacity Market, together averaging 80.8 percent (See Figure 5-2 and Table 5-2.), down from 87.6 percent for 2006. The combined market share of LSEs not affiliated with any EDC and of non-PJM EDC affiliates averaged 19.2 percent, up from 12.4 percent for 2006.

LSEs could meet their load obligations through self-supply, the PJM CCM or bilateral contracts with third parties.[13] As shown in Table 5-3, Table 5-4 and Table 5-5, reliance on these options varied by market sector.[14]

During January though May 2007, PJM EDCs self-supplied an average of 69.8 percent of their load obligations with their remaining obligations being supplied through bilateral contracts with third parties (32.1 percent) and the PJM CCM (0.4 percent). The self-supply percentage was up from the 2006 value of 56.7 percent, while the bilateral contract percentage decreased from 45.8 percent for 2006. In January through May 2007, entities in this sector, on average, purchased more capacity credits in the PJM CCM or through bilateral contracts with third parties than were required to meet their obligation, resulting in an average net excess of 1,785 MW (2.3 percent of obligation) as compared to a 2006 average net excess of 2,171 MW (2.4 percent of obligation) for this sector.

During January though May 2007, as in 2006, PJM EDC generating affiliates owned more capacity than their load obligations, were net capacity credit sellers both in the PJM CCM and through bilateral contracts and, except for non-PJM EDC generating affiliates, remained in higher net excess positions as a percentage of load obligations than the other sectors.

During January though May 2007, as in 2006, PJM EDC marketing affiliates were net capacity credit buyers in the PJM CCM and through bilateral contracts and bought more capacity credits than required to meet their obligation.

13 Self-supply is defined as the unforced MW of the units owned by an entity.

14 Negative values in the "Capacity Credit Market" and in the "Net Bilateral Contracts" columns mean that a sector sold more capacity credits than it purchased for the relevant time period. A positive number means that a sector purchased more capacity credits than it sold for the relevant time period.

Table 5-2 PJM Capacity Market load obligation served: January through May 2007

	Average Obligation (MW)							
	PJM EDCs	PJM EDC Generating Affiliates	PJM EDC Marketing Affiliates	Non-PJM EDC Generating Affiliates	Non-PJM EDC Marketing Affiliates	Non-EDC Generating Affiliates	Non-EDC Marketing Affiliates	Total
Jan	75,799	19,955	20,116	3,048	9,095	303	14,719	143,035
Feb	75,614	20,150	20,046	3,007	9,308	305	14,746	143,176
Mar	75,999	19,749	20,190	3,014	9,375	306	14,830	143,463
Apr	75,985	19,783	20,094	3,011	9,550	307	14,887	143,617
May	76,041	19,709	20,030	3,009	9,677	308	14,968	143,742
Average	75,892	19,864	20,096	3,018	9,402	306	14,831	143,409
Percent of total obligation	52.9%	13.9%	14.0%	2.1%	6.6%	0.2%	10.3%	100.0%

Table 5-3 PJM Capacity Market load obligation served by PJM EDCs and affiliates: January through May 2007

	PJM EDCs					PJM EDC Generating Affiliates					PJM EDC Marketing Affiliates				
	Self-Supply (MW)	CCM (MW)	Net Bilateral Contracts (MW)	Obligation (MW)	Net Excess (MW)	Self-Supply (MW)	CCM (MW)	Net Bilateral Contracts (MW)	Obligation (MW)	Net Excess (MW)	Self-Supply (MW)	CCM (MW)	Net Bilateral Contracts (MW)	Obligation (MW)	Net Excess (MW)
Jan	53,150	952	23,936	75,799	2,239	64,233	(753)	(39,531)	19,955	3,994	0	1,557	19,036	20,116	477
Feb	52,889	366	23,966	75,614	1,607	64,233	(678)	(39,602)	20,150	3,803	0	1,606	18,792	20,046	352
Mar	52,790	382	24,559	75,999	1,732	63,570	(581)	(39,272)	19,749	3,968	0	1,701	18,734	20,190	245
Apr	52,804	252	24,571	75,985	1,642	63,443	(871)	(39,101)	19,783	3,688	0	1,719	18,721	20,094	346
May	53,188	(283)	24,822	76,041	1,686	63,016	95	(39,206)	19,709	4,196	0	1,484	18,906	20,030	360
Average	52,966	334	24,377	75,892	1,785	63,690	(553)	(39,339)	19,864	3,934	0	1,613	18,840	20,096	357
Percent of total obligation	69.8%	0.4%	32.1%		2.3%	320.6%	(2.8%)	(198.0%)		19.8%	0.0%	8.0%	93.7%		1.7%

Table 5-4 PJM Capacity Market load obligation served by non-PJM EDC affiliates: January through May 2007

	Non-PJM EDC Generating Affiliates					Non-PJM EDC Marketing Affiliates				
	Self-Supply (MW)	CCM (MW)	Net Bilateral Contracts (MW)	Obligation (MW)	Net Excess (MW)	Self-Supply (MW)	CCM (MW)	Net Bilateral Contracts (MW)	Obligation (MW)	Net Excess (MW)
Jan	12,601	(604)	(6,980)	3,048	1,969	0	1,622	7,716	9,095	243
Feb	12,601	(911)	(6,878)	3,007	1,805	0	2,073	7,532	9,308	297
Mar	12,715	(1,057)	(6,828)	3,014	1,816	0	2,143	7,514	9,375	282
Apr	12,715	(763)	(6,979)	3,011	1,962	0	2,183	7,575	9,550	208
May	12,715	(773)	(7,570)	3,009	1,363	0	2,347	7,574	9,677	244
Average	12,670	(820)	(7,051)	3,018	1,781	0	2,073	7,583	9,402	254
Percent of total obligation	419.8%	(27.2%)	(233.6%)		59.0%	0.0%	22.0%	80.7%		2.7%

Table 5-5 PJM Capacity Market load obligation served by non-EDC affiliates: January through May 2007

	Non-EDC Generating Affiliates					Non-EDC Marketing Affiliates				
	Self-Supply (MW)	CCM (MW)	Net Bilateral Contracts (MW)	Obligation (MW)	Net Excess (MW)	Self-Supply (MW)	CCM (MW)	Net Bilateral Contracts (MW)	Obligation (MW)	Net Excess (MW)
Jan	25,002	(1,669)	(22,187)	303	843	0	(1,106)	16,152	14,719	327
Feb	25,263	(1,950)	(22,056)	305	952	0	(505)	15,888	14,746	637
Mar	25,954	(1,910)	(22,562)	306	1,176	0	(678)	15,852	14,830	344
Apr	26,101	(2,094)	(22,831)	307	869	0	(427)	15,720	14,887	406
May	26,046	(2,196)	(22,738)	308	804	0	(673)	15,998	14,968	357
Average	25,679	(1,963)	(22,481)	306	929	0	(683)	15,924	14,831	410
Percent of total obligation	8,394.2%	(641.8%)	(7,348.9%)		303.5%	0.0%	(4.6%)	107.4%		2.8%

Market Concentration

Market concentration is assessed using market shares, concentration ratios and residual supply indices as measures. Concentration ratios are a summary measure of market share, a key element of market structure. The residual supply index (RSI) is a measure of the extent to which one or more generation owners are pivotal suppliers in a market.[15]

Capacity Credit Market

The pivotal supplier analysis indicates significant market structure issues in the Daily CCM and the Monthly and Multimonthly CCM for January through May 2007.[16] Table 5-6 shows RSI values for the daily CCM auctions and the monthly and multimonthly CCM auctions. The RSI results for the Daily CCM indicate that all daily auctions had three or fewer jointly pivotal suppliers. The average three pivotal supplier RSI level for January through May 2007 was 0.52, while one supplier was individually pivotal in 147 of the 151 daily auctions (97.4 percent). The RSI results for the Monthly and Multimonthly CCM indicate that all of the auctions had three or fewer jointly pivotal suppliers. The average three pivotal supplier RSI was 0.28, while one supplier was individually pivotal in 10 of the 12 monthly auctions (83.3 percent).

15 See the *2007 State of the Market Report*, Volume II, Section 2, "Energy Market, Part 1," for a more detailed discussion of concentration ratios and the Herfindahl-Hirschman Index (HHI) and of the calculation of the residual supply index. See also the *2007 State of the Market Report*, Volume II, Appendix L, "Three Pivotal Supplier Test."

16 The RSI calculations use a market definition that includes those offers with offer prices less than, or equal to, 150 percent of the capacity market-clearing price for the relevant market. This is consistent with the appropriate definition of competitive offers.

Table 5-6 PJM CCM three pivotal supplier residual supply index (RSI): January through May 2007[17]

	Daily Market RSI_3	Monthly and Multimonthly Market RSI_3
Average	0.52	0.28
Minimum	0.43	0.00
Maximum	0.72	0.80
# Auctions	151	12
# Auctions with = 1 pivotal supplier	147	10
% Auctions with = 1 pivotal supplier	97.4%	83.3%
# Auctions with ≤ 3 pivotal suppliers	151	12
% Auctions with ≤ 3 pivotal suppliers	100.0%	100.0%

The HHI analysis indicates that, on average, the PJM CCM in January through May 2007 exhibited moderate levels of concentration in the Daily CCM and high levels of concentration in the Monthly and Multimonthly CCM.[18] As shown in Table 5-7, HHIs for the Daily CCM averaged 1291 during this period, with a maximum of 1552 and a minimum of 952 (four firms with equal market shares would result in an HHI of 2500).[19] The highest market share for any entity in one daily auction was 33.4 percent, while the highest average daily market share for any entity across all of the daily auctions was 21.6 percent.[20] HHIs for the longer-term Monthly and Multimonthly CCM averaged 2519, with a maximum of 5005 and a minimum of 1148. The highest market share for any entity in one monthly/multimonthly auction was 64.0 percent, while the highest average market share for any entity across all of the monthly/multimonthly auctions was 18.7 percent. All but one of the 12 monthly/multimonthly auctions (91.7 percent) had an HHI greater than 1800.

Table 5-7 PJM CCM HHI: January through May 2007

	Daily Market HHI	Monthly and Multimonthly Market HHI
Average	1291	2519
Minimum	952	1148
Maximum	1552	5005
Highest market share (one auction)	33.4%	64.0%
Highest market share (all auctions)	21.6%	18.7%
# Auctions	151	12
# Auctions with HHI >1800	0	11
% Auctions with HHI >1800	0.0%	91.7%

17 RSI_x is the residual supply index, using "x" pivotal suppliers.

18 The HHI calculations use capacity cleared in each respective auction.

19 PJM CCM results are reported by the time period during which the auction was run and not by the time period to which the auction applies.

20 The market share for an entity across all auctions is calculated as the average market share for the entity for all 151 daily auctions or all 12 monthly and multimonthly auctions. For auctions in which an entity did not participate or clear, the entity was assigned a zero market share in the calculation of the multi-auction market share.

Capacity Market – Total Capacity

The CCM market structure analyses include only the 8.2 percent of total PJM capacity obligations that were traded in the PJM CCM during the period from January through May 2007. To provide a more complete assessment of competition in the PJM Capacity Market, the MMU also analyzed total capacity without regard to whether it was sold in the PJM-operated CCM, through bilateral agreements or self-supplied.

The market structure in the aggregate PJM Capacity Market is shown for the beginning of the period (January 1) and the end of the period (May 31) in Table 5-8.

There was a single pivotal supplier throughout the period, with three individual suppliers who were each pivotal on a stand-alone basis. In other words, the capacity owned by any of these individually pivotal suppliers was required in order to meet the total demand for capacity (capacity obligation) in PJM. Total capacity ownership was at low concentration levels throughout the period, with HHI at 911 on January 1 and 895 on May 31.[21] The highest market share increased from 16.2 percent to 16.7 percent.

The market, as defined by total capacity, exhibits significant market structure issues, measured by the pivotal supplier results.[22] As a general matter, the results of the three pivotal supplier test can differ from the results of the HHI and market share tests, and total capacity illustrates that situation. As in this case, the three pivotal supplier test can show the existence of structural market power when the HHI is less than 2500, and the maximum market share is less than 20 percent. The three pivotal supplier test can also show the absence of market power when the HHI is greater than 2500, and the maximum market share is greater than 20 percent. The three pivotal supplier test is more accurate than the HHI and market share tests because it focuses on the relationship between demand and the ownership structure of supply available to meet it.

Table 5-8 PJM capacity: January through May 2007

	01-Jan	31-May
Unforced capacity (MW)	153,149	152,714
Obligation (MW)	142,979	143,780
Net excess (MW)	10,170	8,934
HHI	911	895
Highest market share	16.2%	16.7%
RSI_1	0.90	0.91
RSI_3	0.59	0.61
Pivotal suppliers	1	1

External and Internal Capacity Transactions

PJM capacity resources may be traded bilaterally within PJM and between PJM and external markets.

21 Under the CCM design, total capacity included all capacity in the PJM footprint, but was not a formal market and, therefore, there was no market-clearing price or quantity.
22 See the *2007 State of the Market Report*, Volume II, Appendix L, "Three Pivotal Supplier Test."

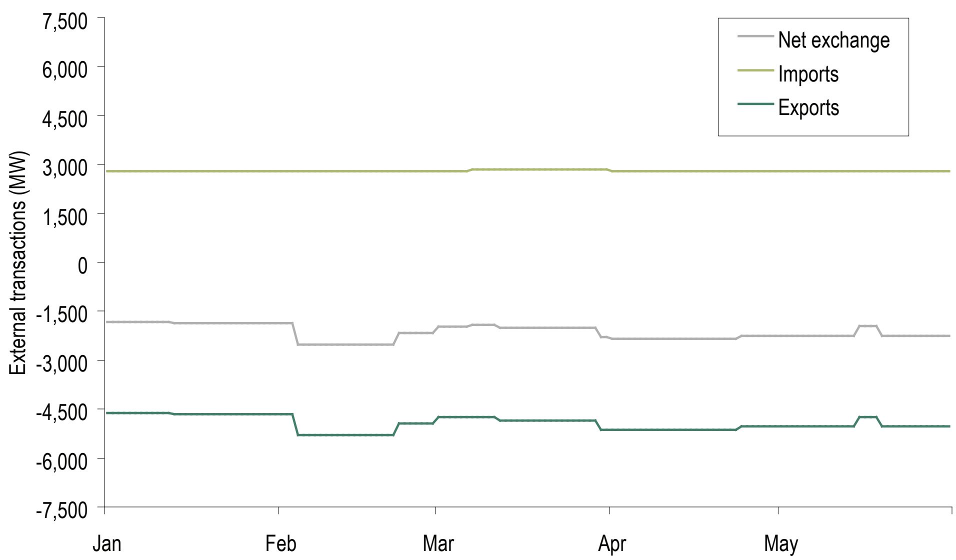
Imports and Exports

External bilateral transactions include imports of capacity resources from other control areas and exports of capacity resources to control areas outside of PJM.[23] Net exchange is equal to imports less exports.

As shown in Table 5-1 and Figure 5-3, Capacity Market participants' external bilateral purchases (imports) of capacity resources were relatively flat in January through May 2007, averaging 2,794 MW, a decrease of 299 MW or 9.7 percent from the average of 3,093 MW for 2006.

During January through May 2007, an average of 4,939 MW of capacity resources was exported from the PJM Capacity Market, a decrease of 19 MW or 0.4 percent from the average of 4,958 MW for 2006. The result was an average net exchange of -2,145 MW of capacity resources for January through May 2007, an increase of 280 MW or 15.0 percent from the average net exchange of -1,865 MW for 2006.

Figure 5-3 External PJM Capacity Market transactions: January through May 2007



Internal Bilateral Transactions

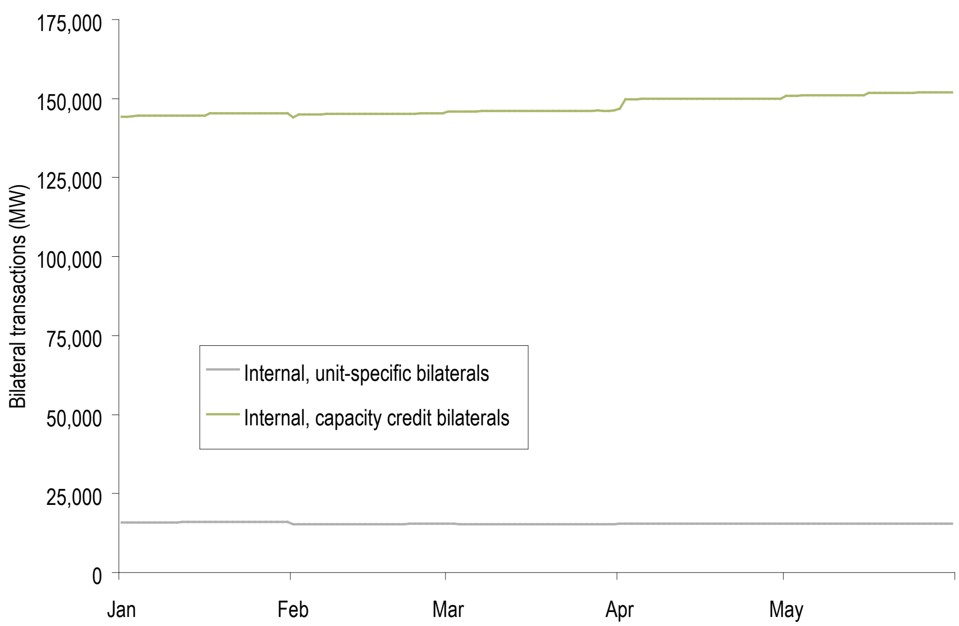
Internal bilateral transactions are agreements between two parties to buy and sell capacity credits within PJM, but outside of the PJM Capacity Credit Market.[24] Unit-specific transactions are for capacity credits from a specific generating unit while capacity credit transactions are for non-unit-specific capacity credits. Both types of transactions may be repeated multiple times among parties, for the same units or credits, with the result that transaction volume can exceed obligation.

23 The sink (destination) of exports cannot be identified since these data are not required from member companies.

24 Through May 31, 2007, only volumes from internal bilateral transactions were reported to PJM. Pricing data were not required from member companies.

During January through May 2007, internal, unit-specific transactions for the PJM Capacity Market averaged 15,495 MW, which was a decrease of 53 MW or 0.3 percent from the average of 15,548 MW for 2006. (See Table 5-1 and Figure 5-4.) Internal capacity credit transactions during January through May 2007 averaged 147,514 MW, which was an increase of 2,110 MW or 1.5 percent from the average of 145,404 MW for 2006. Total internal bilateral transactions in January through May 2007 averaged 163,009 MW, an increase of 2,057 MW or 1.3 percent from the 160,952 MW average for 2006.

Figure 5-4 Internal bilateral PJM Capacity Market transactions: January through May 2007



ALM Credits

ALM reflects the ability of individual customers, under contract with their LSE, to reduce specified amounts of load during an emergency. ALM credits, measured in MW of curtailable load, reduce LSE capacity obligations and thus the total PJM capacity obligation.[25] The ALM construct was replaced when the CCM was replaced by RPM on June 1, 2007.

During January through May 2007, ALM credits in the PJM Capacity Market averaged 1,677 MW, down 151 MW (8.3 percent) from 1,828 MW in 2006. (See Table 5-1.)

25 ALM capacity credits reduce capacity obligations throughout the year. The fixed ALM value for non-summer months (October through May) is calculated by PJM based on daily values of nominated ALM in the PJM eCapacity system for the summer months.

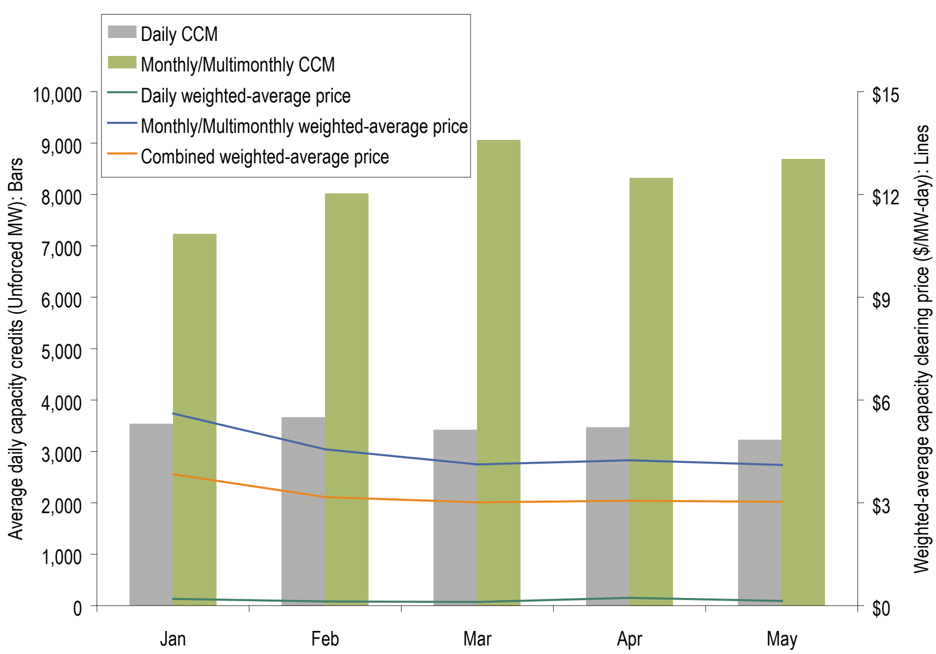
Market Performance

Capacity Credit Market Volumes and Prices

Figure 5-5 and Table 5-9 show prices and volumes in PJM's Daily, Monthly and Multimonthly CCM during January through May 2007. The Daily CCM averaged 3,458 MW of transactions, representing 2.4 percent of the period's 143,409 MW average daily capacity obligation. The average transaction volume for January through May 2007 was 445 MW greater than the 2006 average of 3,013 MW, which had been 2.1 percent of the 142,951 MW average capacity obligations for the period. The Monthly and Multimonthly CCM averaged 8,269 MW of transactions, which was 5.8 percent of the average daily capacity obligations for January through May 2007 and 2,164 MW higher than the 2006 average of 6,105 MW, which was 4.3 percent of the average capacity obligations for the period. Thus, on average, the CCM accounted for 8.2 percent of all average daily capacity obligations in January through May 2007.

The volume-weighted, average price for January through May 2007 was $0.16 per MW-day in the Daily CCM and $4.49 per MW-day in the Monthly and Multimonthly CCM. Prices in the Daily CCM during January through May 2007 were $1.76 lower than the 2006 price of $1.92. Prices in the Monthly and Multimonthly CCM were $3.11 lower than the 2006 price of $7.60. The volume-weighted, average price for the entire CCM was $3.21 per MW-day.[26] For calendar year 2006, capacity resources across the entire RTO were valued at a total of $299.0 million. This equals the total capacity obligation valued at the combined-market, weighted-average CCM clearing price for 2006.

Figure 5-5 PJM Daily and Monthly/Multimonthly CCM performance: January through May 2007



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

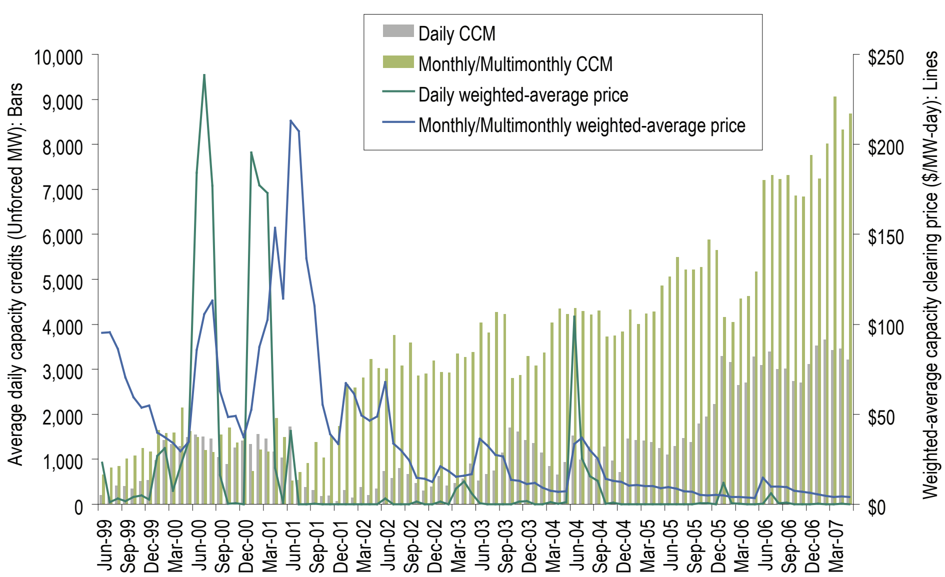
Table 5-9 PJM Capacity Credit Market: January through May 2007

	Average Daily Capacity Credits (MW)			Weighted-Average Price ($ per MW-day)		
	Daily CCM	Monthly and Multimonthly CCM	Combined Markets	Daily CCM	Monthly and Multimonthly CCM	Combined Markets
Jan	3,539	7,236	10,775	$0.19	$5.61	$3.83
Feb	3,664	8,015	11,679	$0.12	$4.56	$3.17
Mar	3,427	9,059	12,486	$0.10	$4.12	$3.02
Apr	3,464	8,325	11,789	$0.23	$4.24	$3.06
May	3,218	8,685	11,903	$0.14	$4.10	$3.03
Average	3,458	8,269	11,727	$0.16	$4.49	$3.21

June 1999 through May 2007

Figure 5-6 and Table 5-10 show prices and volumes in PJM's Daily and longer-term CCM from June 1999 through May 2007.[27] After a series of rule changes including the interval system were introduced in July 2001, overall volume in the CCM increased. After the rule changes, prices declined across the period with the exception of the summers of 2004 and 2006 and the first few days of January 2006. The share of load obligation traded in both the Daily CCM and in the Monthly and Multimonthly CCM remained relatively stable after 2001.

Figure 5-6 PJM Daily and Monthly/Multimonthly CCM performance: June 1999 through May 2007



27 After June 1, 1999, the PJM Capacity Credit Market was based on unforced capacity. Prior to this date, the market had been based on installed capacity.

Table 5-10 PJM Capacity Credit Market: June 1999 to May 2007

	Average Daily Capacity Credits						Weighted-Average Price ($ per MW-day)		
	Daily CCM (MW)	Percent of Obligation	Monthly and Multimonthly CCM (MW)	Percent of Obligation	Combined Markets (MW)	Percent of Obligation	Daily CCM	Monthly and Multimonthly CCM	Combined Markets
1999	374	0.7%	981	1.9%	1,355	2.6%	$4.69	$70.36	$52.24
2000	1,304	2.5%	1,561	3.0%	2,865	5.4%	$69.39	$53.16	$60.55
2001	829	1.5%	1,197	2.2%	2,026	3.7%	$87.98	$100.43	$95.34
2002	450	0.8%	3,066	5.3%	3,516	6.1%	$0.59	$38.21	$33.40
2003	907	1.4%	3,436	5.2%	4,343	6.6%	$2.14	$21.57	$17.51
2004	1,062	1.4%	3,966	5.1%	5,028	6.5%	$17.21	$17.88	$17.74
2005	1,516	1.2%	4,968	3.9%	6,484	5.1%	$0.15	$7.94	$6.12
2006	3,013	2.1%	6,105	4.3%	9,118	6.4%	$1.92	$7.60	$5.73
2007	3,458	2.4%	8,269	5.8%	11,727	8.2%	$0.16	$4.49	$3.21

RPM Capacity Market

Market Design

On June 1, 2007, the RPM Capacity Market design was implemented in the PJM region, replacing the CCM Capacity Market design that had been in place since 1999.[28] The RPM market design differs from the CCM market design in a number of important ways. The RPM is a forward-looking, annual, locational market with a must-offer requirement for capacity and mandatory participation by load that includes clear, market power mitigation rules and that permits the direct participation of demand-side resources. CCM, in contrast, was a daily, single-price, voluntary balancing market that included less than 10 percent of total PJM capacity, that had no explicit market power mitigation rules and that did permit the participation of demand-side resources. Under RPM, capacity obligations are annual. Under CCM, capacity obligations were daily. Under RPM, auctions are held for delivery years that are three years in the future. Under CCM daily, monthly and multimonthly auctions were held. Under RPM, prices are locational and may vary depending on transmission constraints.[29] Under CCM, prices were the same, regardless of location. Under RPM, sell offers are unit-specific. Under CCM, offers were non-unit-specific capacity credits. Under RPM, existing generation capable of qualifying as a capacity resource must be offered into RPM Auctions, except for the FRR option. Under CCM, there was no must-offer rule after June 2000. Under RPM, participation by LSEs is mandatory, except for the FRR option. Under CCM, there was no mandatory participation in the CCM auctions.[30] Under RPM there is an administratively determined demand curve that, with the supply curve derived from capacity offers, determines market prices. Under CCM the demand was defined by participant buy bids. Under RPM there are explicit market power mitigation rules that define structural market power, that define offer caps based on the marginal cost of capacity and that do not limit prices offered by new entrants. Under CCM,

28 For additional information on the RPM, see PJM. "Manual 18: PJM Capacity Market," Revision 2 (Effective February 21, 2008), p. 11 <http://www.pjm.com/contributions/pjm-manuals/pdf/m18.pdf> (604 KB).

29 Transmission constraints are local capacity import capability limitations (low CETL margin over CETO) caused by transmission facility limitations, voltage limitations or stability limitations.

30 See "Reliability Assurance Agreement among Load-Serving Entities in the PJM Region," Schedule 8.1 (June 1, 2007) (Accessed July 19, 2007) <http://www.pjm.com/documents/downloads/agreements/raa.pdf> (1.92 MB).

there were no explicit market power mitigation rules. Under RPM, demand-side resources may be offered directly into the auctions and receive the clearing price. Under CCM, demand-side resources could not be offered directly into the market.

The first four base RPM Auctions comprise the RPM transition period.[31] Three base RPM Auctions were held during 2007 in April, July and October for the delivery years 2007/2008, 2008/2009 and 2009/2010, respectively.[32] A fourth transition period auction was held in January 2008 for the delivery year 2010/2011. After this transition period, annual base auctions will be held in May for delivery years that are three years in the future. First, second and third incremental RPM Auctions may be held for each delivery year, occurring 23, 13 and four months, respectively, prior to the delivery year. The first incremental auction to be held by PJM was the third incremental auction for 2008/2009, held in January 2008.[33]

Market Structure

Supply

As shown in Table 5-11, total internal capacity increased from 154,985.5 MW on January 1, 2007, to 155,206.0 MW on June 1, 2007, or 220.5 MW.[34] This increase was the result of 573.2 MW from DR offered into the auction, offset in part by 332.6 MW from higher EFORds and 20.1 MW from generation deratings. No new generation was offered into the 2007/2008 RPM Auction.

In the 2008/2009 and 2009/2010 auctions, new generation increased 528.6 MW; 112.6 MW were brought out of retirement and net generation uprates were 220.3 MW, for a total of 861.5 MW. DR offers increased 815.9 MW through June 1, 2009. Net improvements in EFORds added 434.8 MW. The net effect from May 31, 2007, through June 1, 2009, was an increase in total internal capacity of 2,350.6 MW (1.5 percent) from 154,967.6 MW to 157,318.2 MW.

As shown in Table 5-11 and Table 5-17, in the 2008/2009 RPM Auction, the increase of 15 units included five new wind units (66.1 MW), three new diesel units (23.3 MW) and two units (112.6 MW) which came out of retirement while the remaining five units were the result of a reclassification of external units.[35] There were 23 DR resources offered compared to 15 DR resources offered in the 2007/2008 RPM Auction.[36]

As also shown in Table 5-11 and Table 5-17, in the 2009/2010 RPM Auction, the increase of 17 units included eight new CT units (380.2 MW), two new diesel units (9.2 MW) and one new steam unit (49.8 MW) while the remaining increase of six units was the result of a combination of more units imported, less units exported, a decrease in units excused from offering into the auction and fewer units removed from the auction under the FRR option. There were 38 DR resources offered compared to 23 DR resources offered in the 2008/2009 RPM Auction.

31 For more detailed analysis of the 2007/2008, 2008/2009 and 2009/2010 RPM Auctions, see: "Analysis of the 2007-2008 RPM Auction" (August 16, 2007); "Analysis of the 2008-2009 RPM Auction" (November 30, 2007); "Analysis of the 2009-2010 RPM Auction" (November 30, 2007) < http://www.pjm.com/markets/market-monitor/reports.html.>

32 Delivery years are from June 1 through May 31. The 2007/2008 delivery year runs from June 1, 2007, through May 31, 2008.

33 More detailed analyses of individual RPM Auctions have been developed by the PJM Market Monitoring Unit and are posted on the Web site at < http://www.pjm.com/markets/market-monitor/reports.html.>

34 Unless otherwise specified, all volumes and prices are in terms of UCAP, which is calculated as installed capacity (ICAP) times (1-EFORd). The EFORd values here are the EFORd values used in the RPM Auctions.

35 Certain external hydroelectric units were allocated from the LDA level to the zonal level, resulting in an increased unit count.

36 Some generation and DR resources had multiple associated offers.

Table 5-11 Internal capacity: January 1, 2007, through June 1, 2009[37]

	UCAP (MW)			
	RTO	EMAAC	SWMAAC	MAAC+APS
Total internal capacity @ 01-Jan-07	154,985.5			
Generation capmods	(17.9)			
Total internal capacity @ 31-May-07	154,967.6	30,845.7	10,441.5	
New generation	0.0	0.0	0.0	
Units out of retirement	0.0	0.0	0.0	
Generation capmods	(2.2)	(65.3)	(109.0)	
DR mods	573.2	44.7	19.7	
Net EFORd effect	(332.6)	0.0	0.0	
Total internal capacity @ 01-Jun-07	155,206.0	30,825.1	10,352.2	
New generation	89.4	0.0	0.0	
Units out of retirement	112.6	112.6	0.0	
Generation capmods	146.2	105.9	38.9	
DR mods	595.3	298.7	294.3	
Net EFORd effect	818.5	36.8	91.7	
Total internal capacity @ 01-Jun-08	156,968.0	31,379.1	10,777.1	72,889.5
New generation	439.2		0.0	109.9
Units out of retirement	0.0		0.0	0.0
Generation capmods	74.1		(298.2)	(149.7)
DR mods	220.6		42.3	163.2
Net EFORd effect	(383.7)		(176.0)	0.0
Total internal capacity @ 01-Jun-09	157,318.2		10,345.2	73,012.9

Demand

There was a 5,298.6 MW increase in the RPM reliability requirement, which is similar to the obligation under CCM, from 142,978.7 MW on January 1, 2007, to 148,277.3 MW on June 1, 2007. This increase resulted from a higher peak-load forecast starting June 1.

On June 1, 2007, PJM EDCs and their affiliates maintained a large market share of load obligations under RPM, together totaling 77.5 percent (Table 5-12), down from an average of 80.8 percent for the first five months of 2007 under CCM. The combined market share of LSEs not affiliated with any EDC and of non-PJM EDC affiliates was 22.5 percent, up from an average of 19.2 percent for the first five months of 2007 under CCM. Obligation is defined as cleared MW plus ILR forecast obligations.

37 The RTO includes MAAC+APS, EMAAC and SWMAAC. MAAC+APS includes EMAAC and SWMAAC. In the 2009/2010 RPM Auction, EMAAC was not constrained, so results for it are not shown. Maps of the LDAs can be found in the *2007 State of the Market Report*, Appendix A, "PJM Geography."

Table 5-12 PJM Capacity Market load obligation served: June 1, 2007

	Obligation (MW)							
	PJM EDCs	PJM EDC Generating Affiliates	PJM EDC Marketing Affiliates	Non-PJM EDC Generating Affiliates	Non-PJM EDC Marketing Affiliates	Non-EDC Generating Affiliates	Non-EDC Marketing Affiliates	Total
Obligation	58,455.6	21,006.3	22,132.6	948.8	10,623.8	222.3	17,680.3	131,069.7
Percent of total obligation	44.6%	16.0%	16.9%	0.7%	8.1%	0.2%	13.5%	100.0%

Market Concentration

Preliminary Market Structure Screen

Under the terms of the PJM Tariff, the MMU is required to apply the PMSS prior to RPM auctions.[38] The purpose of the PMSS is to determine whether additional data are needed from owners of capacity resources in the defined areas in order to permit the MMU to apply the market structure tests defined in the Tariff.

An LDA or the RTO Region fails the PMSS if any one of the following three screens is failed: the market share of any capacity resource owner exceeds 20 percent; the HHI for all capacity resource owners is 1800 or higher; or there are not more than three jointly pivotal suppliers.[39]

As shown in Table 5-13, all defined markets failed the PMSS. As a result, capacity resource owners were required to submit avoidable cost rate (ACR) data to the MMU for resources for which they intended to submit nonzero sell offers unless certain other conditions were met.[40]

38 See PJM. "Open Access Transmission Tariff (OATT)," "Attachment DD: Reliability Pricing Model," Original Sheet No. 605 (Effective June 1, 2007), section 6.3 (a) i.

39 See PJM. "Open Access Transmission Tariff (OATT)," "Attachment DD: Reliability Pricing Model," Original Sheet No. 605 (Effective June 1, 2007), section 6.3 (a) ii.

40 See PJM. "Open Access Transmission Tariff (OATT)," "Attachment DD: Reliability Pricing Model," First Revised Sheet No. 610 (Effective June 20, 2007), section 6.7 (c).

Table 5-13 Preliminary market structure screen results: 2007/2008 through 2009/2010 RPM Auctions

RPM Markets	Highest Market Share	HHI	Pivotal Suppliers	Pass/Fail
2007/2008				
RTO	16.0%	895	1	Fail
EMAAC	32.0%	2155	1	Fail
SWMAAC	49.8%	4259	1	Fail
2008/2009				
RTO	18.5%	879	1	Fail
EMAAC	33.1%	2180	1	Fail
SWMAAC	47.5%	4290	1	Fail
2009/2010				
RTO	18.4%	853	1	Fail
SWMAAC	51.1%	4229	1	Fail
MAAC+APS	26.9%	1627	1	Fail

Auction Market Structure

As shown in Table 5-14, all participants in the total PJM market as well as the LDA RPM markets failed the TPS test in each auction.[41] The result was that offer caps were applied to all sell offers. The RTO market includes all supply which cleared at or below the unconstrained clearing price. The LDA markets include the incremental supply in the LDAs which was required to meet the demand for capacity in each LDA and which cleared at a price higher than the unconstrained price.

41 The market definition used for the TPS test includes all offers with costs less than or equal to 1.50 times the clearing price. The appropriate market definition to use for the one pivotal supplier test includes all offers with costs less than, or equal to, 1.05 times the clearing price. See the *2007 State of the Market Report*, Appendix L, "Three Pivotal Supplier Test" for additional discussion.

Table 5-14 RSI results: 2007/2008 through 2009/2010 RPM Auctions

RPM Markets	$RSI_{1\ 1.05}$	RSI_3
2007/2008		
RTO	0.82	0.59
EMAAC	0.12	0.01
SWMAAC	0.06	0.00
2008/2009		
RTO	0.82	0.61
EMAAC	1.10	0.25
SWMAAC	0.32	0.00
2009/2010		
RTO	0.82	0.60
MAAC+APS	0.83	0.37
SWMAAC	0.57	0.00

Imports and Exports

As shown in Table 5-15, net exchange decreased 707.6 MW from January 1 to June 1. Net exchange, which is imports less exports, increased due to a decrease in exports of 682.9 MW and an increase in imports of 24.7 MW.

Table 5-15 PJM capacity summary (MW): January 1, 2007, through June 1, 2009

		1-Jan-07	31-May-07	01-Jun-07	01-Jun-08	01-Jun-09
Installed capacity (ICAP)		162,840.7	162,036.6	163,721.1	164,444.1	166,916.0
Unforced capacity (pre-RPM)	A	153,148.6	152,714.3	154,076.7	155,590.2	157,628.7
Cleared capacity	B			129,409.2	129,597.6	132,231.8
Obligation/RPM reliability requirement (pre-FRR)	C	142,978.7	143,780.2	148,277.3	150,934.6	153,480.1
Obligation/RPM reliability requirement (less FRR)	D			125,805.0	128,194.6	130,447.8
Net excess (pre-RPM)	A-C	10,169.9	8,934.1	5,799.4	4,655.6	4,148.6
Net excess (RPM)	B-D+E-F			5,240.5	3,066.6	3,445.7
Imports		2,784.5	2,784.6	2,809.2	2,460.3	2,505.4
Exports		(4,621.4)	(5,038.0)	(3,938.5)	(3,838.1)	(2,194.9)
Net exchange		(1,836.9)	(2,253.4)	(1,129.3)	(1,377.8)	310.5
ALM		1,676.7	1,676.7			
DR cleared				127.6	536.2	892.9
ILR	E			1,636.3	2,109.9	2,107.5
FRR DR	F				446.3	445.8
HHI		911	895	895	879	853
Highest market share		16.2%	16.7%	16.0%	18.5%	18.4%
RSI_3		0.59	0.61	0.59	0.61	0.60
Pivotal suppliers		1	1	1	1	1

Demand-Side Resources

As part of the RPM redesign of the Capacity Market, the PJM ALM program was replaced by the PJM load management (LM) program. Under ALM, providers had received a MW credit which offset their capacity obligation. With the introduction of LM, qualifying load management resources can be offered into RPM Auctions as capacity resources and receive the clearing price, or they can be offered outside of the auction and receive the final, zonal ILR price.

The LM program introduced two RPM-related products. DR resources are load resources that are offered into an RPM Auction as capacity and receive the relevant LDA or RTO resource-clearing price. ILR resources are load resource that are not offered into the RPM Auction, but receive the final, zonal ILR price determined after the close of the second incremental auction.

Under the ALM program, resources could be nominated at any time prior to the day that ALM was called upon by PJM. Under RPM, DR resources must be offered into the auction for the delivery year during which they will participate while ILR resources must be certified by a published deadline which is after the base auction for the delivery year but at least three months prior to the delivery year during which they will participate.

As shown in Table 5-16, capacity in the RPM load management programs, which is a combination of DR cleared in the RPM Auctions and certified/forecast ILR, increased from the 1,676.7 MW in the CCM ALM program by 87.2 MW on June 1, 2007, by an additional 882.2 MW on June 1, 2008, and an additional 354.3 MW on June 1, 2009. Final ILR will be certified three months before the delivery year and it may differ from the ILR forecast.

Table 5-16 Load management statistics: May 31, 2007, through June 1, 2009

	UCAP (MW)			
	RTO	EMAAC	SWMAAC	MAAC+APS
DR cleared	127.6	44.7	19.7	
ILR certified	1,636.3	387.0	273.4	
Total load management @ 01-June-2007	1,763.9	431.7	293.1	
DR cleared	536.2	168.7	309.2	
ILR forecast	2,109.9	396.1	346.2	
Total load management @ 01-June-2008	2,646.1	564.8	655.4	
DR cleared	892.9		356.3	813.9
ILR forecast	2,107.5		345.7	1,055.7
Total load management @ 01-June-2009	3,000.4		702.0	1,869.6
ALM @ 31-May-2007	1,676.7			

Market Conduct

Offer Caps

If a capacity resource owner failed the market power test for the auction, avoidable costs were used to calculate offer caps for that owner's resources. Avoidable costs are the costs that a generation owner would not incur if the generating unit did not operate for one year, in particular the delivery year.[42] In effect, avoidable costs are the costs that a generation owner would not incur if the generating unit were mothballed for the year. In the calculation of avoidable costs, there is no presumption that the unit would retire as the alternative to operating, although that possibility could be reflected if the owner documented that retirement was the alternative. Avoidable costs also include annual capital recovery associated with investments required to maintain a unit as a capacity resource. This component of avoidable costs is termed the avoidable project investment recovery rate (APIR). Avoidable costs are the defined costs less net revenues from all other PJM markets and from unit-specific bilateral contracts. The specific components of avoidable costs are defined in the PJM Tariff.

Capacity resource owners could provide ACR data by providing their own unit-specific data, by selecting the default ACR values calculated by the MMU, by submitting an opportunity cost for a possible export, by inputting a transition adder or by using combinations of these options. The opportunity cost option for exports allows resource owners to input a documented export price as the opportunity cost offer for the unit. If the relevant RPM market clears above the opportunity cost, the unit's capacity is sold in the RPM market. If the opportunity cost is greater than the clearing price, the unit's capacity does not clear in the RPM market and it is available for export. The transition adder was added to the offer cap, if appropriate, regardless of the offer-cap calculation method.[43]

2007/2008 RPM Auction

As shown in Table 5-17, of the 1,061 generating units which submitted offers, unit-specific offer caps were calculated for 125 units (11.8 percent). Offer caps of all kinds were used by 566 units (53.4 percent), of which 388 were the default (proxy) offer caps calculated and posted by the MMU. Of the 1,061 generating units, the remaining 495 units were price takers, of which the offers for 492 units were zero and the offers for three units were set to zero because no data were submitted. The transition adder was part of 263 offers, of which 50 offers included only the transition adder. The transition adder had no impact on the clearing prices. Fifteen DR resources offered into the auction.

Of the 1,061 generating units which submitted offers, 69 (6.5 percent) included an APIR component. (See Table 5-17.) As shown in Table 5-18, of the $79.34 per MW-day of ACR, the APIR component added $18.50 per MW-day to the ACR value of these 69 units in 2007/2008.[44] The default ACR values include an average APIR of $0.91 per MW-day. As the APIR component increased over the next two auctions to $195.85 per MW-day in 2009/2010, offer caps correspondingly increased as well from a weighted-average

42 See PJM. "Open Access Transmission Tariff (OATT)," "Attachment DD: Reliability Pricing Model," Original Sheet No. 617 (Effective June 1, 2007), section 6.8 (b).

43 The transition adder, which is added to the calculated offer cap, is $10.00 per MW-day for delivery years 2007/2008 and 2008/2009 and $7.50 per MW-day for delivery year 2009/2010. It can be applied only up to 3,000 MW of unforced capacity per owner, only in unconstrained markets and only by those parent companies which own no more than 10,000 MW of unforced capacity in PJM.

44 The 69 units which had an APIR component submitted $141.3 million for capital projects on 7,681.1 MW UCAP.

of $16.99 per MW-day in 2007/2008 to $55.74 per MW-day in 2009/2010. The highest APIR was for subcritical/supercritical coal units. The maximum APIR effect ($133.86 per MW-day in 2007/2008) is the maximum amount by which an offer cap was increased by APIR.

Table 5-17 ACR statistics: 2007/2008 through 2009/2010 RPM Auctions[45]

	2007/2008		2008/2009		2009/2010	
Calculation Type	Number of Units	Percent of Generating Units Offered	Number of Units	Percent of Generating Units Offered	Number of Units	Percent of Generating Units Offered
Default ACR selected	388	36.6%	399	37.1%	377	34.5%
ACR data input (non-APIR)	56	5.3%	37	3.4%	22	2.0%
ACR data input (APIR)	69	6.5%	80	7.4%	129	11.8%
Opportunity cost input	3	0.3%	8	0.7%	10	0.9%
Transition adder only	50	4.7%	43	4.0%	12	1.1%
Offer caps calculated	566	53.4%	567	52.6%	550	50.3%
Uncapped new units	0	0.0%	0	0.0%	3	0.3%
Generator price takers	495	46.6%	509	47.4%	540	49.4%
Generating units offered	1,061	100.0%	1,076	100.0%	1,093	100.0%
Demand resources offered	15		23		38	
Total capacity resources offered	1,076		1,099		1,131	

45 This table has been updated since the report on the 2007/2008 RPM Auction was posted.

Table 5-18 APIR statistics: 2007/2008 through 2009/2010 RPM Auctions[46, 47]

	Weighted-Average ($ per MW-day UCAP)					
	Combined Cycle	Combustion Turbine	Oil or Gas Steam	SubCritical/ SuperCritical Coal	Other	Total
2007/2008						
ACR	$37.93	$24.25	$76.55	$157.69	$31.43	$79.34
Net revenues	$69.09	$23.03	$22.65	$330.84	$142.88	$148.63
Offer caps	$12.86	$11.30	$59.01	$12.70	$10.66	$16.99
APIR	$0.69	$10.73	$17.54	$44.87	$0.00	$18.50
Maximum APIR effect						$133.86
2008/2009						
ACR	$37.65	$23.87	$88.09	$170.64	$50.14	$93.34
Net revenues	$63.51	$20.93	$23.72	$339.52	$271.26	$169.83
Offer caps	$14.57	$12.40	$64.90	$22.34	$13.07	$21.93
APIR	$0.80	$4.92	$28.47	$131.38	$15.54	$49.29
Maximum APIR effect						$211.28
2009/2010						
ACR	$40.99	$29.78	$106.57	$278.10	$57.60	$146.22
Net revenues	$69.54	$21.68	$25.39	$332.89	$269.63	$178.73
Offer caps	$17.37	$17.06	$105.75	$74.18	$34.48	$55.74
APIR	$0.24	$22.86	$43.79	$386.13	$18.96	$195.85
Maximum APIR effect						$383.79

2008/2009 RPM Auction

As shown in Table 5-17, 1,076 generating units submitted offers into the 2008/2009 RPM Auction as compared to the 1,061 generating units offered in the 2007/2008 RPM Auction. Unit-specific offer caps were calculated for 117 units (10.8 percent). Offer caps of all kinds were used by 567 units (52.6 percent), of which 399 were the default (proxy) offer caps calculated and posted by the MMU. Of the 1,076 generating units, the remaining 509 units were price takers, of which the offers for 472 units were zero and the offers for 37 units were set to zero because no data were submitted. The transition adder was part of the offers on 255 units, of which offers on 43 units included only the transition adder. The transition adder had no impact on the clearing prices.

Of the 1,076 generating units which submitted offers, 80 (7.4 percent) included an APIR component. (See Table 5-17.) As shown in Table 5-18, of the $93.34 per MW-day of ACR, the APIR component added

46 The weighted-average offer cap can still be positive even when the weighted-average net revenues are higher than the weighted-average ACR due to the offer-cap minimum being zero. On a unit basis, if net revenues are greater than ACR, net revenues in an amount equal to the ACR are used in the calculation and the offer cap is zero.

47 The weighted-average APIR is only for those units which had an APIR component, while the weighted-average values for ACR, net revenues and offer caps are for all units which submitted ACR data.

$49.29 per MW-day to the ACR value of these 80 units in 2008/2009.[48] The default ACR values include an average APIR of $0.91 per MW-day. The maximum APIR effect ($211.28 per MW-day) is the maximum amount by which an offer cap was increased by APIR. This value is less than the maximum APIR ($283.09 per MW-day) because of the net revenue offset to ACR plus APIR.

2009/2010 RPM Auction

As shown in Table 5-17, 1,093 generating units submitted offers in the 2009/2010 RPM Auction as compared to 1,076 generating units offered in the 2008/2009 RPM Auction. Unit-specific offer caps were calculated for 151 units (13.8 percent). Offer caps of all kinds were used by 550 units (50.3 percent), of which 377 were the default (proxy) offer caps calculated and posted by the MMU. Of the 1,093 generating units, three new units had uncapped offers while the remaining 540 units were price takers, of which the offers for 514 units were zero and the offers for 26 units were set to zero because no data were submitted.[49] The transition adder was part of the offers on 206 units, of which offers on 12 units included only the transition adder. The transition adder had no impact on the clearing prices.

Of the 1,093 generating units which submitted offers, 129 (11.8 percent) included an APIR component. (See Table 5-17.) As shown in Table 5-18, of the $146.22 per MW-day of ACR, the APIR component added $195.85 per MW-day to the ACR value of these 129 units in 2009/2010.[50] The default ACR values include an average APIR of $0.91 per MW-day. The maximum APIR effect ($383.79 per MW-day) is the maximum amount by which an offer cap was increased by APIR. This value is less than the maximum APIR ($808.36 per MW-day) because of the net revenue offset to ACR plus APIR.

Market Performance

Prices for capacity increased from a CCM combined-market, weighted-average price of $3.21 per MW-day for the entire RTO for the first five months of 2007 to a 2007/2008 high of $197.67 per MW-day (EMAAC), a 2008/2009 high of $210.11 per MW-day (SWMAAC) and a 2009/2010 high of $237.33 per MW-day (SWMAAC). The combined CCM/RPM 2007 weighted-average price was $88.09 per MW-day. (See Table 5-19.)

As Table 5-15 shows, net excess as calculated under CCM decreased 6,021.3 MW from 10,169.9 MW on January 1, 2007, to 4,148.6 MW on June 1, 2009, because of a 10,501.4 MW increase in the RPM reliability requirement, which is similar to the obligation under CCM, from 142,978.7 MW to 153,480.1 MW.[51] This increase was caused by a higher peak-load forecast and was partially offset by an increase of 4,480.1 MW in unforced capacity (pre-RPM) from 153,148.6 MW on January 1, 2007, to 157,628.7 MW on June 1, 2009.[52] The increase in unforced capacity was the result of a decrease in exports of 2,426.5 MW plus a 2,332.7 MW growth in total internal capacity (Table 5-11), both of which were partially offset by a decrease

48 Of the 80 units which had an APIR component, 77 units had current year capital dollars submitted of $421.1 million on 7,234.9 MW UCAP. Three units had APIR based only on the inclusion of 2007/2008 capital projects.

49 Generally, planned units are not subject to mitigation. The seven other planned units submitted zero price offers. See PJM. "Open Access Transmission Tariff (OATT)," "Attachment DD: Reliability Pricing Model," Original Sheet No. 617 (Effective June 1, 2007), section 6.5 (a) ii.

50 Of the 129 units which had an APIR component, 109 units had current year capital dollars submitted of $2.5 billion on 14,519.2 MW UCAP. Twenty units had APIR based only on the inclusion of 2007/2008 and 2008/2009 capital projects.

51 Net excess under CCM was calculated as unforced capacity less obligation.

52 Unforced capacity (pre-RPM) is defined as the UCAP value of iron in the ground plus the UCAP value of imports less the UCAP value of exports.

in imports of 279.1 MW. On June 1, 2009, net excess as calculated under RPM (3,445.7 MW) was 702.9 MW less than the 4,148.6 MW as calculated under CCM.[53]

Table 5-19 Capacity prices: January 1, 2007, through May 31, 2010

	CCM Combined Markets Weighted-Average Price ($ per MW-day)	RPM Clearing Price ($ per MW-day) RTO	EMAAC	SWMAAC	MAAC+APS
Jan	$3.83				
Feb	$3.17				
Mar	$3.02				
Apr	$3.06				
May	$3.03				
Jun 07 - May 08		$40.80	$197.67	$188.54	
Jun 08 - May 09		$111.92	$148.80	$210.11	
Jun 09 - May 10		$102.04		$237.33	$191.32
Average	$3.21				
2007 weighted-average CCM/RPM	$88.09				

2007/2008 RPM Auction

Cleared capacity resources across the entire RTO, accounting for LDA prices and volumes, will receive a total of $4.3 billion.

RTO

Table 5-20 shows total RTO offer data for the 2007/2008 RPM Auction, which includes the EMAAC and SWMAAC LDAs. Total internal RTO unforced capacity of 155,206.0 MW includes all generating units and DR that qualified as a PJM capacity resource for the 2007/2008 RPM Auction, excluding external units, and also includes owners' modifications to installed capacity ratings which are permitted under the PJM Reliability Assurance Agreement (RAA) and associated manuals.[54]

After accounting for FRR committed resources and for imports, RPM capacity was 135,092.6 MW.[55] This amount was reduced by exports of 3,938.5 MW[56] and 270.3 MW which were excused from the RPM must-offer requirement as a result of environmental regulations (151.0 MW), generation moving behind the meter (13.3 MW), non-utility generator (NUG) ownership questions (18.4 MW), expected unit retirements (79.8 MW) and other factors (7.8 MW). Subtracting 35.8 MW of FRR optional volumes not offered, resulted in

53 Net excess under RPM is calculated as cleared capacity less the reliability requirement plus ILR. For 2007/2008, certified ILR is used. For 2008/2009 and 2009/2010, forecast ILR less FRR DR is used in the calculation.

54 See "Reliability Assurance Agreement among Load-Serving Entities in the PJM Region" (June 1, 2007) (Accessed July 19, 2007) <http://www.pjm.com/documents/downloads/agreements/raa.pdf> (1.92 MB).

55 The FRR alternative allows an LSE, subject to certain conditions, to avoid direct participation in the RPM Auctions. The LSE is required to submit an FRR capacity plan to satisfy the unforced capacity obligation for all load in its service area.

56 If all of the exports had been offered into the auction at $0.00 per MW-day, the clearing price would have been approximately $12.00 per MW-day.

130,848.0 MW that were available to be offered into the auction.[57] Offered volumes included 811.9 MW of EFORd offer segments. Only 4.3 MW, from multiple resources, were unoffered into the RPM Auction, which had no effect on either the RTO or LDA resource-clearing prices. No new generating units were offered in the auction.

The downward sloping demand curve resulted in more capacity cleared in the market than the reliability requirement. The 129,409.2 unforced MW of cleared resources for the entire RTO represented a reserve margin of 19.8 percent, which was 3,604.2 MW greater than the reliability requirement of 125,805.0 MW (IRM of 15.0 percent).[58, 59, 60] As shown in Figure 5-7, the downward sloping demand curve resulted in a price of $40.80 per MW-day. Net excess was 5,240.5 MW, which was a decrease of 3,693.6 MW from the net excess of 8,934.1 MW on May 31, 2007. (See Table 5-15.) This decrease in net excess was mainly because of an increase in the RTO load forecast of 3,921.0 MW from 133,500.0 MW to 137,421.0 MW, effective June 1, 2007. Certified ILR was 1,636.3 MW.

As shown in Table 5-20, the net load price that LSEs will pay is $40.69 per MW-day in the RTO area not included in the constrained LDAs. This value is the final zonal capacity price. The final zonal capacity price is the resource-clearing price adjusted for differences between the certified ILR for the delivery year and the forecasted RTO ILR obligation.

57 FRR entities are allowed to offer into the RPM Auction excess volumes above their FRR quantities, subject to a sales' cap amount. The 35.8 MW are excess volumes included in the sales' cap amount which were not offered into the auction.

58 Both the reserve margin calculation and IRM include FRR resources and FRR load and are on an ICAP basis.

59 The RTO reliability requirement, which is after FRR adjustments, is plotted on the variable resource requirement (VRR) curve as the reliability requirement less the ILR forecast obligation plus any FRR DR.

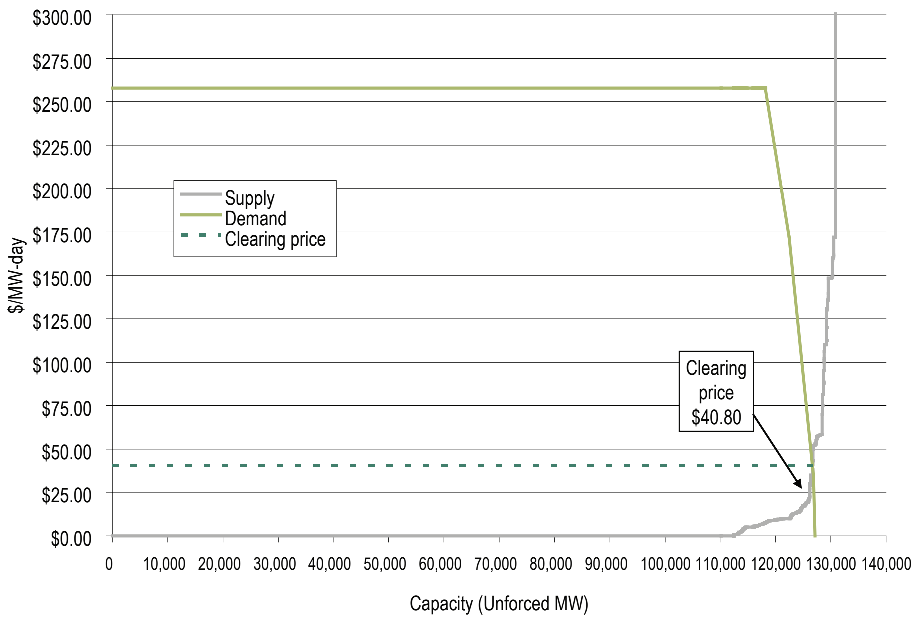
60 The demand curve UCAP quantities are based on three points, which are ratios of the installed reserve margin (IRM =15.0 percent) times the reliability requirement, less the forecast RTO ILR obligation. For the three points, the ratios are 1.12/1.15, 1.16/1.15 and 1.20/1.15. For these three points the UCAP prices are based on factors multiplied by net cost of net entry (CONE) divided by one minus the pool-wide EFORd. Net CONE is defined as CONE minus the energy and ancillary service revenue offset (E&AS). For the three points, the factors are 1.5, 1.0 and 0.2. For 2007/2008, CONE was $197.29 per MW-day and E&AS was $36.02 MW-day.

Table 5-20 RTO offer statistics: 2007/2008 RPM Auction[61]

	ICAP (MW)	UCAP (MW)	Percent of Available ICAP	Percent of Available UCAP
Total internal RTO capacity (gen and DR)	165,111.2	155,206.0		
FRR	(24,717.0)	(22,922.6)		
Imports	2,983.8	2,809.2		
RPM capacity	143,378.0	135,092.6		
Exports	(4,373.9)	(3,938.5)		
FRR optional	(43.0)	(35.8)		
Excused	(463.4)	(270.3)		
Available	138,497.7	130,848.0	100.0%	100.0%
Generation offered	138,369.0	130,716.1	99.9%	99.9%
DR offered	123.5	127.6	0.1%	0.1%
Total offered	138,492.5	130,843.7	100.0%	100.0%
Unoffered	5.2	4.3	0.0%	0.0%
Cleared in RTO	134,034.1	126,666.7	96.8%	96.8%
Cleared in LDAs	2,949.5	2,742.5	2.1%	2.1%
Total cleared	136,983.6	129,409.2	98.9%	98.9%
Uncleared in RTO	1,479.1	1,405.1	1.1%	1.1%
Uncleared in LDAs	29.8	29.4	0.0%	0.0%
Total uncleared	1,508.9	1,434.5	1.1%	1.1%
Reliability requirement		125,805.0		
Total cleared		129,409.2		
ILR certified		1,636.3		
Net excess/(deficit)		5,240.5		
Resource clearing price ($ per MW-day)		$40.80	A	
Final zonal capacity price ($ per MW-day)		$40.69	B	
Final zonal CTR credit rate ($ per MW-day)		$0.00	C	
Final zonal ILR price ($ per MW-day)		$40.80	A-C	
Net load price ($ per MW-day)		$40.69	B-C	

61 Prices are only for those generating units outside of EMAAC and SWMAAC.

Figure 5-7 RTO market supply/demand curves: 2007/2008 RPM Auction[62, 63]



EMAAC

Table 5-21 shows total EMAAC offer data for the 2007/2008 RPM Auction. Total internal EMAAC unforced capacity of 30,825.1 MW includes all generating units and DR that qualified as a PJM capacity resource, excluding external units, and also includes owners' modifications to ICAP ratings. Including imports of 15.9 MW into EMAAC, RPM unforced capacity was 30,841.0 MW. This amount was reduced by 13.3 MW which were excused from the RPM must-offer requirement as a result of generation moving behind the meter, resulting in 30,827.7 MW that were available to be offered into the auction. Only 0.5 MW were unoffered into the RPM Auction, which had no effect on either the RTO or LDA resource-clearing prices.

Of the 30,797.8 MW cleared in EMAAC, 28,705.4 MW were cleared in the RTO before EMAAC became constrained. Once the constraint was binding, based on the 5,845.0 MW CETL value, only the incremental supply located in EMAAC was available to meet the incremental demand in the LDA. Of the 2,121.8 MW of incremental supply, 2,092.4 MW cleared, which resulted in a resource-clearing price of $197.67 per MW-day, as shown in Figure 5-8. The price was determined by the intersection of the incremental supply and demand curves. The uncleared MW were the result of offer prices which exceeded the demand curve.

62 The supply curve includes all supply offers at the lower of offer price or offer cap. The demand curve excludes incremental demand which cleared in EMAAC and SWMAAC.

63 For ease of viewing, the graph was truncated at $300.00 per MW-day and does not show an uncleared offer of approximately $800.00 per MW-day.

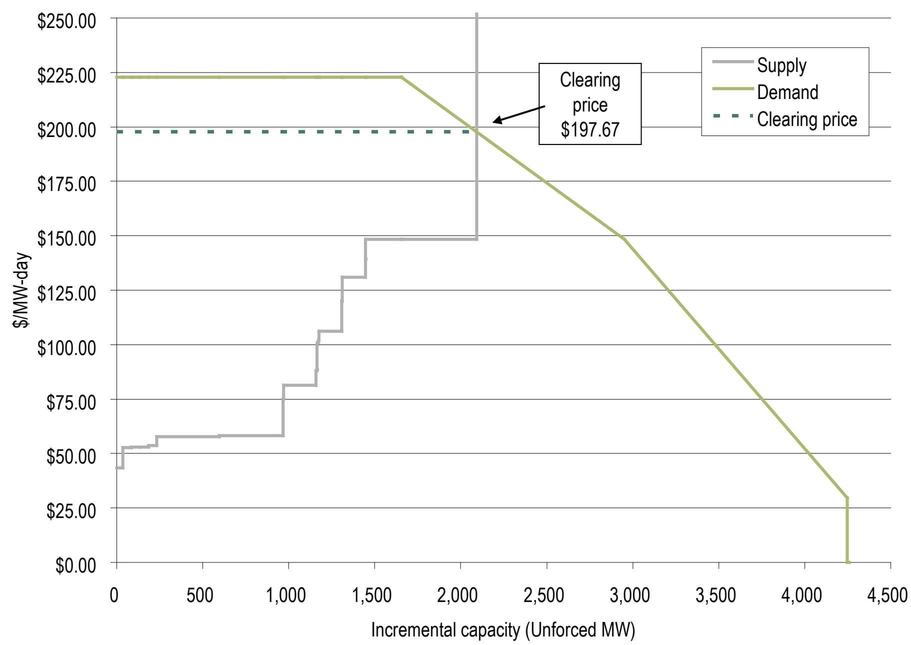
Total resources in EMAAC were 36,642.8 MW, which when combined with certified ILR of 387.0 MW resulted in a net excess of -206.9 MW (0.6 percent) less than the reliability requirement of 37,236.7 MW.

As shown in Table 5-21, the net load price that LSEs will pay is $177.00 per MW-day. This value is the final zonal capacity price ($197.16 per MW-day) less the final CTR credit rate ($20.16 per MW-day). The CTR MW value allocated to load in an LDA is the LDA UCAP obligation less the cleared generation internal to the LDA less the ILR forecast for the LDA. This MW value is multiplied by the locational price adder for the LDA to arrive at the economic value of the CTRs allocated to the load in the LDA. This value is then divided by the LDA UCAP obligation to arrive at the final CTR credit rate for the LDA. The final CTR credit rate is an allocation of the economic value of transmission import capability that exists in constrained LDAs and serves to offset a portion of the locational price adder charged to load in constrained LDAs.

Table 5-21 EMAAC offer statistics: 2007/2008 RPM Auction

	ICAP (MW)	UCAP (MW)	Percent of Available ICAP	Percent of Available UCAP
Total internal EMAAC capacity (gen and DR)	32,942.3	30,825.1		
Imports	15.9	15.9		
RPM capacity	32,958.2	30,841.0		
Exports	0.0	0.0		
Excused	(14.1)	(13.3)		
Available	32,944.1	30,827.7	100.0%	100.0%
Generation offered	32,900.2	30,782.5	99.9%	99.9%
DR offered	43.3	44.7	0.1%	0.1%
Total offered	32,943.5	30,827.2	100.0%	100.0%
Unoffered	0.6	0.5	0.0%	0.0%
Cleared in RTO	30,634.2	28,705.4	93.0%	93.1%
Cleared in LDA	2,279.5	2,092.4	6.9%	6.8%
Total cleared	32,913.7	30,797.8	99.9%	99.9%
Uncleared	29.8	29.4	0.1%	0.1%
Reliability requirement		37,236.7		
Total cleared		30,797.8		
CETL		5,845.0		
Total resources		36,642.8		
ILR certified		387.0		
Net excess/(deficit)		(206.9)		
Resource clearing price ($ per MW-day)		$197.67	A	
Final zonal capacity price ($ per MW-day)		$197.16	B	
Final zonal CTR credit rate ($ per MW-day)		$20.16	C	
Final zonal ILR price ($ per MW-day)		$177.51	A-C	
Net load price ($ per MW-day)		$177.00	B-C	

Figure 5-8 EMAAC incremental supply/demand curves: 2007/2008 RPM Auction[64]



SWMAAC

Table 5-22 shows total SWMAAC offer data for the 2007/2008 RPM Auction. Total internal SWMAAC unforced capacity of 10,352.2 MW includes all generating units and DR that qualified as a PJM capacity resource, excluding external units, and also includes owners' modifications to ICAP ratings. Since there were no imports from outside PJM into SWMAAC, RPM unforced capacity was 10,352.2 MW. This amount was reduced by 151.0 MW which were excused from the RPM must-offer requirement as a result of environmental regulations, resulting in 10,201.2 MW that were available to be offered into the auction. All capacity resources were offered into the RPM Auction.

Of the 10,201.2 MW cleared in SWMAAC, 9,551.1 MW had cleared in the RTO before SWMAAC became constrained. Once the constraint was binding, based on the 5,699.0 CETL value, only the incremental supply in SWMAAC was available to meet incremental demand in the LDA. All of the 650.1 MW of incremental supply cleared, but since there was not enough incremental supply to meet incremental demand, the resource-clearing price of $188.54 per MW-day was set by the demand curve. (See Figure 5-9.)

Total resources in SWMAAC were 15,900.2 MW, which when combined with certified ILR of 273.4 MW resulted in a net excess of 98.3 MW (0.6 percent) greater than the reliability requirement of 16,075.3 MW.

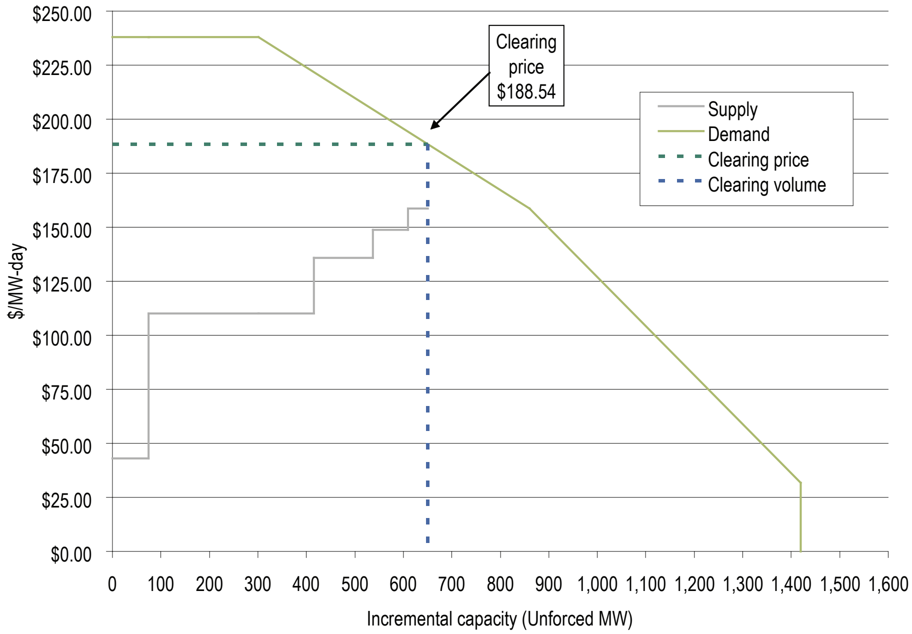
As shown in Table 5-22, the net load price that LSEs will pay is $139.67 per MW-day. This value is the final zonal capacity price ($188.05 per MW-day) less the final CTR credit rate ($48.38 per MW-day).

64 The supply curve was truncated at $250.00 per MW-day and does not show an uncleared offer of approximately $800.00 per MW-day.

Table 5-22 SWMAAC offer statistics: 2007/2008 RPM Auction

	ICAP (MW)	UCAP (MW)	Percent of Available ICAP	Percent of Available UCAP
Total internal SWMAAC capacity (gen and DR)	11,546.1	10,352.2		
Imports	0.0	0.0		
RPM capacity	11,546.1	10,352.2		
Exports	0.0	0.0		
Excused	(316.0)	(151.0)		
Available	11,230.1	10,201.2	100.0%	100.0%
Generation offered	11,211.1	10,181.5	99.8%	99.8%
DR offered	19.0	19.7	0.2%	0.2%
Total offered	11,230.1	10,201.2	100.0%	100.0%
Unoffered	0.0	0.0	0.0%	0.0%
Cleared in RTO	10,560.1	9,551.1	94.0%	93.6%
Cleared in LDA	670.0	650.1	6.0%	6.4%
Total cleared	11,230.1	10,201.2	100.0%	100.0%
Uncleared	0.0	0.0	0.0%	0.0%
Reliability requirement		16,075.3		
Total cleared		10,201.2		
CETL		5,699.0		
Total resources		15,900.2		
ILR certified		273.4		
Net excess/(deficit)		98.3		
Resource clearing price ($ per MW-day)		$188.54	A	
Final zonal capacity price ($ per MW-day)		$188.05	B	
Final zonal CTR credit rate ($ per MW-day)		$48.38	C	
Final zonal ILR price ($ per MW-day)		$140.16	A-C	
Net load price ($ per MW-day)		$139.67	B-C	

Figure 5-9 SWMAAC incremental supply/demand curves: 2007/2008 RPM Auction



Generator Performance

Generator performance is a function of incentives from energy and capacity markets as well as the physical nature of the units and the level of expenditures made to maintain the capability of the units. Generator performance can be measured using indices calculated from historical data. Generator performance indices include those based on total hours in a period (generator performance factors) and those based on hours when units are needed to operate by the system operator (generator forced outage rates). In state of the market reports prior to 2006, the generator performance analysis was based solely on the capacity resources in the PJM Mid-Atlantic Region and the AP Control Zone. The generator performance analysis for the *2006 State of the Market Report* and the *2007 State of the Market Report* includes all PJM capacity resources for which there are data in the PJM GADS database.[65]

Generator Performance Factors

Generator performance factors are based on a defined period, usually a year, and are directly comparable.[66] Performance factors include the equivalent availability factor (EAF), the equivalent maintenance outage factor (EMOF), the equivalent planned outage factor (EPOF) and the equivalent forced outage factor (EFOF). These four factors add to 100 percent for any generating unit. The EAF is the proportion of hours in a year when a unit is available to generate at full capacity while the three outage factors include all the hours when a unit is unavailable. The EMOF is the proportion of hours in a year when a unit is unavailable because of

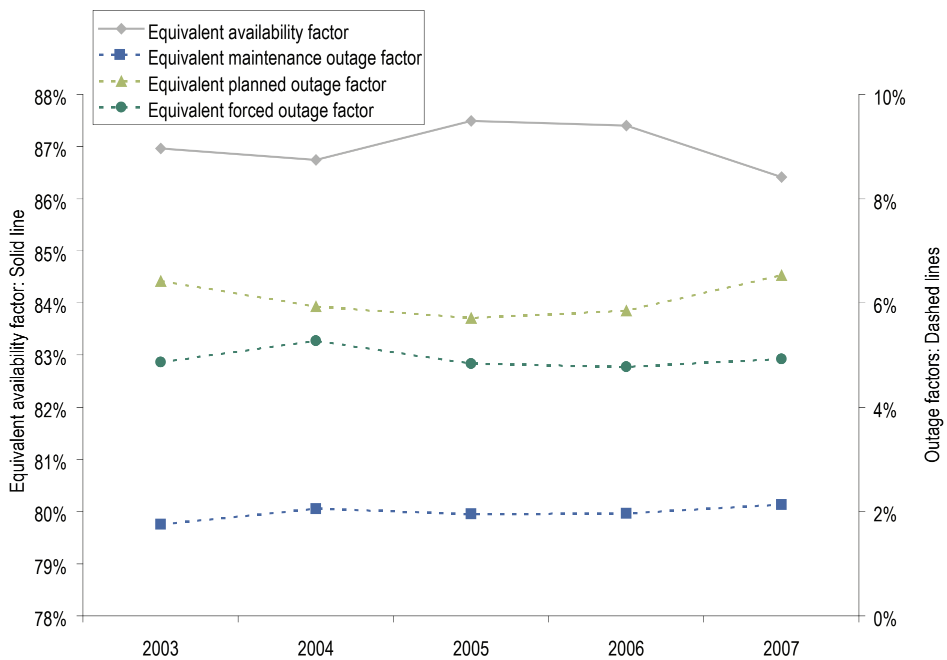
65 This set of capacity resources may include generators in addition to those in the set of generators committed as resources in the RPM.

66 Data from all PJM capacity resources for the years 2003 through 2007 were analyzed.

maintenance outages and maintenance deratings. The EPOF is the proportion of hours in a year when a unit is unavailable because of planned outages and planned deratings. The EFOF is the proportion of hours in a year when a unit is unavailable because of forced outages and forced deratings.

The PJM aggregate EAF decreased from 87.4 percent in 2006 to 86.4 percent in 2007. The EFOF increased by 0.1 percentage points from 2006 to 2007 while the EPOF increased by about 0.7 percentage points and the EMOF increased 0.2 percentage points.[67] (See Figure 5-10.)

Figure 5-10 PJM equivalent outage and availability factors: Calendar years 2003 to 2007



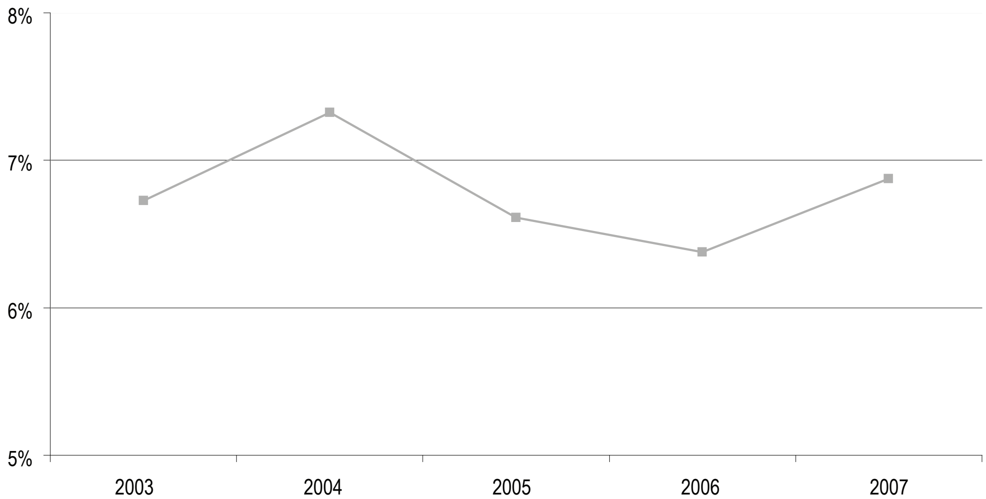
Generator Forced Outage Rates

The equivalent demand forced outage rate (EFORd) (generally referred to as the forced outage rate) is a measure of the probability that a generating unit will fail, either partially or totally, to perform when it is needed to operate. EFORd is calculated using historical performance data. Unforced capacity for any individual generating unit is equal to one minus the EFORd multiplied by the unit's net dependable summer capability. The PJM Capacity Market creates an incentive to minimize the forced outage rate because the amount of capacity resources available to sell from a unit (i.e., unforced capacity) is inversely related to the forced outage rate.

67 The performance factor data include all units from the PJM Control Area. Data for the year 2007 may be incomplete as of the download date as corrections can be made at any time with permission from the PJM GADS administrators. Data are for 12 months ended December 31, 2007, as downloaded from the PJM GADS database on January 23, 2008.

EFORd[68] calculations use historical data, including equivalent forced outage hours,[69] service hours, average forced outage duration, average run time, average time between unit starts, available hours and period hours.[70] The average PJM EFORd increased from 6.7 percent in 2003 and 7.3 percent in 2004 before it decreased to 6.6 percent in 2005 and 6.4 percent in 2006 and again increased to 6.9 in 2007.[71] Figure 5-11 shows the average EFORd since 2003 for all units in the PJM Control Area.

Figure 5-11 Trends in the PJM equivalent demand forced outage rate (EFORd): Calendar years 2003 to 2007[72]



68 EFORd was calculated using data for all units contained in the PJM GADS database. PJM systemwide EFORd is a capacity-weighted average of individual unit EFORd.

69 Equivalent forced outage hours are the sum of all forced outage hours in which a generating unit is fully inoperable and all partial forced outage hours in which a generating unit is partially inoperable prorated to represent full hours.

70 See PJM. "Manual 22: Generator Resource Performance Indices," Revision 15 (June 1, 2007), Equations 2 through 5.

71 Data are for the 12 months ended December 31, 2007, as downloaded from the PJM GADS database on January 23, 2008. Data for the year 2007 may be incomplete as of the download date as corrections can be made at anytime with permission from PJM GADS administrators.

72 Data for 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.

Components of Change in EFORd

Table 5-23 shows the contribution of each unit type to the system EFORd, calculated as the total forced MW for the unit type divided by the total capacity of the system.[73] Forced MW for a unit type is the EFORd multiplied by the generator's net dependable summer capability.

Table 5-23 Contribution to EFORd for specific unit types (Percentage points): Calendar years 2003 to 2007[74]

	2003	2004	2005	2006	2007	Change in 2007 from 2006
Combined cycle	0.4	0.6	0.7	0.5	0.4	(0.1)
Combustion turbine	1.1	1.3	1.5	1.4	1.7	0.3
Diesel	0.0	0.0	0.0	0.0	0.0	0.0
Hydroelectric	0.1	0.2	0.1	0.1	0.1	0.0
Nuclear	0.6	0.6	0.3	0.3	0.3	0.0
Steam	4.4	4.6	4.0	4.0	4.3	0.3
Total	6.7	7.3	6.6	6.4	6.9	0.5

The increase in overall PJM Control Area EFORd of 0.5 percentage points (a 7.8 percent increase) between 2006 and 2007 resulted primarily from poorer performance of combustion turbine units (494 generating units) and steam units (317 generating units) which together accounted for 0.6 of the 0.5 percentage point overall increase.[75] This increase was partially offset by the improved performance of combined-cycle units (106 generating units).

Of the 1,216 generating units in the EFORd analysis, during calendar year 2007, 283 units had decreased EFORds, 532 units had increased EFORds and the remaining 401 units had unchanged EFORds. If the 283 units with lower forced outage rates had not experienced rates lower than the average, the 2007 EFORd would have been 9.3 percent.

Changes in outage rates by unit type and changes in capacity by unit type combined to produce the observed impacts on system EFORd. Since total capability from both combustion turbine and fossil steam units remained nearly the same from year to year, the increased forced outage rates for these unit types were the reason for their contribution to the increased system EFORd.

Table 5-24 shows the relative contributions of EFORd and capacity to EFORd levels by unit type and for the system. Approximately 117 percent of the contribution of combustion turbine units to the increased combustion turbine EFORd was the result of increased combustion turbine EFORd while minus 17 percent of the contribution of combustion turbine units to the increased combustion turbine EFORd was the result of lower capacity levels for combustion turbines. Approximately minus 3 percent of the contribution of

73 The generating unit types are: steam, nuclear, diesel, combustion turbine, combined-cycle and hydroelectric. For all tables, run of river and pumped storage hydroelectric are combined into a single hydroelectric category.

74 Calculated values presented in Section 5, "Capacity Market," "Generator Performance" are based on unrounded, underlying data and may differ from those derived from the rounded values shown in the tables.

75 A single unit may include more than one set of generator terminals aggregated as a single generator.

combined-cycle units to the decreased combined-cycle EFORd was the result of increased combined-cycle capacity while 103 percent of the contribution of combined-cycle units to the decreased combined-cycle EFORd was the result of lower EFORd levels for combined-cycle units. Overall, 119 percent of the increase in EFORd from 2006 to 2007 was the result of increased EFORd for specific unit types while the balance was the result of the change in the mix of capacity by unit type.

Table 5-24 Percent change in contribution to EFORd (Unit type): 2007 compared to 2006

	Contribution Change Due to Capacity	Contribution Change Due to EFORd
Combined cycle	(3.2%)	103.2%
Combustion turbine	(16.7%)	116.7%
Diesel	17.3%	82.7%
Hydroelectric	(18.3%)	118.3%
Nuclear	1.5%	98.5%
Steam	(16.6%)	116.6%
All unit types	(18.8%)	118.8%

Table 5-25 Five-year PJM EFORd data comparison to NERC five-year average for different unit types: Calendar years 2003 to 2007

	2003	2004	2005	2006	2007	NERC 2002 to 2006
Combined cycle	5.4%	5.5%	5.3%	4.2%	3.2%	6.2%
Combustion turbine	8.1%	8.7%	9.8%	9.3%	11.5%	10.7%/10.1%
Diesel	7.9%	8.9%	14.0%	13.1%	11.4%	11.1%
Hydroelectric	2.2%	3.9%	2.5%	1.9%	2.0%	3.2%
Nuclear	3.2%	3.2%	1.6%	1.4%	1.7%	4.1%
Steam	8.3%	9.2%	8.1%	8.2%	8.7%	7.1%
Overall	6.7%	7.3%	6.6%	6.4%	6.9%	NA

Table 5-25 compares PJM EFORd data by unit type to North American Electric Reliability Council (NERC) data for corresponding unit types.[76] The 2007 PJM forced outage rates for combined-cycle, hydroelectric and nuclear units were below the NERC five-year averages. The 2007 PJM EFORd for diesel, combustion turbine and fossil steam units exceeded the NERC averages.[77]

Duty Cycle and EFORd

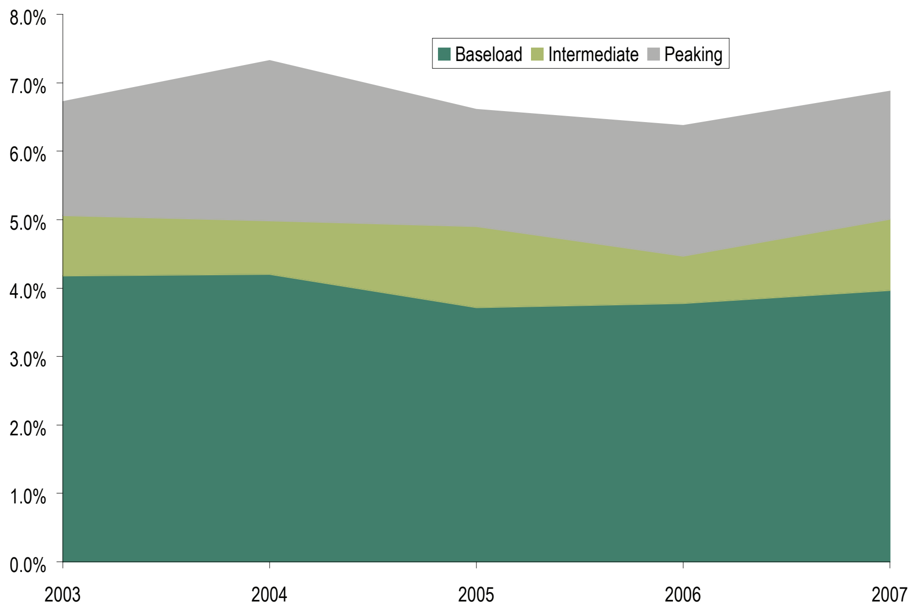
In addition to disaggregating system EFORd by unit type, units were categorized by actual duty cycles as baseload, intermediate or peaking to determine the relationship between type of operation and forced

76 The PJM data include all combustion turbines as a single unit type.

77 NERC defines combustion turbines in two categories: jet engines and gas turbines. Their EFORd for the 2002 to 2006 period are 10.7 percent and 10.1 percent, respectively, per NERC's GADS "2002-2006 Generating Unit Statistical Brochure - Units Reporting Events" <ftp://ftp.nerc.com/pub/sys/all_updl/gads/gar/2002_2006_Generating_Unit_Statistical_Brochure_Unit_Reporting_Events.zip> (28 KB). Also, the NERC average for fossil steam units is a unit-year-weighted value for all units reporting. The PJM Control Area values are weighted by capability for each calendar year.

outage rates.[78] Figure 5-12 shows the contribution of unit types to system average EFORd. In 2007, of 22,600 MW of combined-cycle units, approximately 20,700 MW are in the intermediate (18,100 MW) and peaking (2,600 MW) classes. Of 27,200 MW of combustion turbine units approximately 26,700 MW are in the intermediate (1,900 MW) and peaking (24,800 MW) classes.

Figure 5-12 Contribution to EFORd by duty cycle: Calendar years 2003 to 2007



Forced Outage Analysis

The MMU analyzed the causes of forced outages for the entire PJM system. The metric used was lost generation, which is the product of the duration of the outage and the size of the outage reduction. Lost generation can be converted into lost system equivalent availability.[79] On a systemwide basis, the resultant lost equivalent availability from the forced outages is equal to the equivalent forced outage factor.

The PJM EAF for 2007 was 86.4 percent; the corresponding EMOF and EPOF were 2.1 percent and 6.5 percent, respectively. As a result, the 2007 PJM EFOF was 4.9 percent. This means 4.9 percent lost availability because of forced outages.

The major reasons for this lost equivalent availability are listed in Table 5-26.

78 Duty cycle is the time the unit is generating divided by the time the unit is available to generate. A baseload unit is defined as a unit that generates during 50 percent or more of its available hours. An intermediate unit is defined as a unit that generates during from 10 percent to 50 percent of its available hours. A peaking unit is defined as a unit that generates during less than 10 percent of its available hours. These terms were defined for the purposes of this analysis.

79 For any unit, lost generation can be converted to lost equivalent availability by dividing lost generation by the product of the generating units' capacity and period hours. This can also be done on a systemwide basis.

Table 5-26 Outage cause contribution to PJM EFOF: Calendar year 2007

	Percentage Point Contribution to EFOF	Contribution to EFOF
Boiler tube leaks	1.08	21.9%
Electrical	0.25	5.0%
Performance	0.20	4.0%
Boiler fuel supply from bunkers to boiler	0.20	4.0%
Miscellaneous (jet engine)	0.16	3.2%
Boiler air and gas systems	0.16	3.2%
Feedwater system	0.16	3.2%
Economic	0.14	2.8%
Miscellaneous (generator)	0.12	2.5%
Miscellaneous (steam turbine)	0.12	2.5%
Stack emission	0.10	2.1%
Boiler piping system	0.10	2.0%
Generator	0.10	2.0%
Controls	0.10	2.0%
Miscellaneous (gas turbine)	0.09	1.9%
Cooling system	0.09	1.9%
Auxiliary systems	0.09	1.9%
Regulatory	0.09	1.8%
Fuel quality	0.08	1.7%
All other causes	1.50	30.4%
PJM EFOF 2007	4.93	100.0%

Table 5-26 shows that boiler tube leaks, at 21.9 percent of the systemwide EFOF, were the largest single contributor to EFOF. Forced outages because of boiler tube leaks reduced system equivalent availability by 1.08 percentage points. Electrical problems caused the second largest reduction to equivalent availability by 0.25 percentage points. Performance caused the third largest reduction to equivalent availability by 0.20 percentage points. Almost all of this reduction was attributable to failing, in whole or in part, PJM seasonal capacity verification tests which require an outage until the problem is solved or the generator takes a capacity derating.

Table 5-27 Contribution to EFOF by unit type for the most prevalent causes: Calendar year 2007

	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Steam	System
Boiler tube leaks	0.4%	0.0%	0.0%	0.0%	0.0%	29.9%	21.9%
Electrical	4.0%	12.0%	3.8%	1.9%	2.2%	4.0%	5.0%
Performance	15.1%	13.1%	4.1%	7.1%	1.7%	1.5%	4.0%
Boiler fuel supply from bunkers to boiler	0.5%	0.0%	0.0%	0.0%	0.0%	5.4%	4.0%
Miscellaneous (jet engine)	0.0%	22.7%	0.0%	0.0%	0.0%	0.0%	3.2%
Boiler air and gas systems	0.0%	0.0%	0.0%	0.0%	0.0%	4.4%	3.2%
Feedwater system	2.4%	0.0%	0.0%	0.0%	6.9%	3.6%	3.2%
Economic	1.6%	4.3%	0.1%	3.4%	0.0%	2.8%	2.8%
Miscellaneous (generator)	8.9%	5.0%	12.9%	5.9%	1.2%	1.6%	2.5%
Miscellaneous (steam turbine)	2.5%	0.0%	0.0%	0.0%	1.4%	3.1%	2.5%
Stack emission	0.1%	1.0%	0.7%	0.0%	0.0%	2.6%	2.1%
Boiler piping system	7.4%	0.0%	0.0%	0.0%	0.0%	2.2%	2.0%
Generator	2.3%	0.8%	0.1%	23.8%	0.0%	2.0%	2.0%
Controls	3.8%	0.4%	0.0%	2.3%	4.6%	1.9%	2.0%
Miscellaneous (gas turbine)	7.1%	10.7%	0.0%	0.0%	0.0%	0.0%	1.9%
Cooling system	1.1%	0.2%	0.0%	0.0%	4.4%	2.2%	1.9%
Auxiliary systems	2.8%	9.3%	0.0%	0.3%	0.3%	0.5%	1.9%
Regulatory	0.0%	0.0%	1.4%	0.0%	0.0%	2.4%	1.8%
Fuel quality	0.7%	0.1%	3.3%	0.0%	0.0%	2.3%	1.7%

Table 5-27 shows the major causes of EFOF by unit type. Boiler tube leaks caused 29.9 percent of the EFOF for fossil steam units. Feedwater system problems caused 6.9 percent of the EFOF for nuclear units. Generator outages caused 23.8 percent of the EFOF for hydroelectric units.

Table 5-28 Contribution to EFOF by unit type: Calendar year 2007

	EFOF	Contribution to EFOF
Combined cycle	2.1%	5.7%
Combustion turbine	4.7%	14.2%
Diesel	9.1%	0.4%
Hydroelectric	1.5%	1.1%
Nuclear	1.5%	5.4%
Steam	7.3%	73.2%
PJM systemwide	4.9%	100.0%

The contribution to systemwide EFOF by a generator or group of generators is a function of duty cycle, EFORd and share of the systemwide capacity mix. For example, fossil steam units have the largest share (about 49 percent) of the capacity mix,[80] have a high duty cycle and in 2007 had an EFORd of 8.7 percent

80 See the *2007 State of the Market Report*, Volume II, Section 3, "Energy Market, Part 2," "Existing and Planned Generation," at Table 3-38, "PJM capacity age (MW)."

which yields a 73.2 percent contribution to PJM systemwide EFOF. Nuclear units also have a high duty cycle; their share of the PJM systemwide capacity mix is about 18 percent and in 2007 they had a 1.7 percent EFORd which yields a 5.4 percent contribution to PJM systemwide EFOF. By using the values in Table 5-28 and Table 5-27 one can determine how much the individual unit types' causes contributed to PJM systemwide EFOF. For instance the value for boiler tube leaks in Table 5-27 multiplied by the contribution value in Table 5-28 for the same unit type will yield the percent contribution to the PJM systemwide EFOF for that outage cause.

Outages Deemed Outside Management Control

In 2006, NERC created specifications for certain types of outages that should be deemed outside management control (OMC) in response to the system disturbance of August 14, 2003.[81] NERC specified, in its January 2006 update to the "Generator Availability Data System Data Reporting Instructions,"[82] in Appendix K,[83] that each OMC outage must be carefully considered as to its cause and nature. An outage can be classified as an OMC outage only if the generating unit outage was caused by other than failure of the owning company's equipment or other than the failure of the practices, policies and procedures of the owning company. Appendix K of the "Generator Availability Data Systems Data Reporting Instructions" lists specific cause codes (i.e., codes that are standardized for specific outage causes) that would be considered OMC outages.[84] Not all outages caused by the factors in these specific OMC cause codes are OMC outages. For example, fuel quality issues (i.e., codes 9200 to 9299) may be within the control of the owner or outside management control. Each outage must be considered per the NERC directive. In 2007, PJM removed the OMC designation from all of the fuel quality codes with the exception of 9250, "low Btu coal" since only that code had both an OMC and non-OMC code (i.e., 9250, OMC code for "low Btu coal"; 9251, non-OMC code for "low Btu coal"). After analyzing the data for these outages types, it was found that in 2006, of 17 companies that used either of these cause codes, only three had used both the OMC and non-OMC cause codes. In other words, 14 companies exclusively used the OMC cause code. In 2007, however, of 39 companies that used either of the OMC and non-OMC fuel quality cause codes, only one company exclusively used the OMC cause code. In 2006, approximately 51 percent of the lost generation because of "low Btu coal" was deemed OMC by the generation owners. In 2007, only 6 percent of the lost generation because of "low Btu coal" was deemed OMC. It is not clear why some companies, in 2006, exclusively used the OMC cause codes and did not use the non-OMC cause code for "low Btu coal." In 2007, companies seem to have used the non-OMC and OMC cause codes for fuel quality more appropriately. It is a reasonable expectation that companies would monitor coal quality stringently and reject noncompliant shipments. It is also possible that these outages are a function of issues with generating plant equipment. PJM should scrutinize OMC outages for low Btu coal carefully to ensure that only appropriate outages are classified as OMC.

All outages, including OMC outages, are included in the EFORd that is used for planning studies that determine the reserve requirement. However, OMC outages will be excluded from the calculations used to

81 NERC had always provided cause codes for outages that were caused by external forces. However, as a result of the system disturbance on August 14, 2003, NERC specifically created outage specifications for outages that were "outside management control."

82 The "Generator Availability Data System Data Reporting Instructions" can be found on the NERC Web site: <ftp://ftp.nerc.com/pub/sys/all_updl/gads/dri/2008_GADS_DRI.pdf> (4.9 MB).

83 The "Generator Availability Data System Data Reporting Instructions," Appendix K can be found on the NERC Web site: <ftp://ftp.nerc.com/pub/sys/all_updl/gads/dri/apd-k_Outside_Plant_Management_Control.pdf> (161 KB).

84 For a list of these cause codes, see the *2007 State of the Market Report*, Volume II, Appendix E, "Capacity Market."

determine the level of unforced capacity for specific units and thus the amount of unforced capacity for sale in Capacity Markets. This modified EFORd is termed the XEFORd. All submitted OMC outages are reviewed by PJM's Capacity Adequacy Department. Table 5-29 shows the impact of OMC outages on EFORd for 2007. The difference is especially noticeable for peaking units (combustion turbines and diesels). Combustion turbine and diesel units have natural gas fuel curtailment outages deemed as OMC. If companies' natural gas fuel supply is curtailed because of pipeline issues, the event can be deemed OMC. However, natural gas curtailments caused by lack of firm transportation contracts or arbitraging transportation reservations should not be classified as OMC. In 2007, XEFORd was 0.7 percentage points less than EFORd, which translates into a 1,225 MW difference in unforced capacity.

Table 5-29 PJM EFORd vs. XEFORd: Calendar year 2007

	2007 EFORd	2007 XEFORd	Difference
Combined cycle	3.2%	3.1%	0.2%
Combustion turbine	11.5%	9.6%	1.9%
Diesel	11.4%	9.9%	1.5%
Hydroelectric	2.0%	1.7%	0.3%
Nuclear	1.7%	1.6%	0.1%
Steam	8.7%	8.1%	0.6%
Overall	6.9%	6.2%	0.7%

SECTION 6 – ANCILLARY SERVICE MARKETS

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

Regulation matches generation with very short-term changes in load by moving the output of selected generators up and down via an automatic control signal.[2] Regulation is provided, independent of economic signal, by generators with a short-term response capability (i.e., less than five minutes) or by demand-side response (DSR). 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 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 not for both. The Regulation and the Synchronized Reserve Markets are cleared interactively 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, interarea 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. 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.

The PJM Market Monitoring Unit (MMU) analyzed measures of market structure, conduct and performance of the PJM Regulation Market and of its two Synchronized Reserve Markets for 2007, comparing market results to 2006 and to certain other prior years.[3]

1 75 FERC ¶ 61,080 (1996).

2 Regulation is used to help control the area control error (ACE). See *2007 State of the Market Report,* Volume II, Appendix F, "Ancillary Service Markets," for a full definition and discussion of ACE.

3 During calendar years 2004 and 2005, PJM conducted the phased integration of five control zones: ComEd, American Electric Power (AEP), The Dayton Power & Light Company (DAY), Duquesne Light Company (DLCO) and Dominion. By convention, control zones bear the name of a large utility service provider working within their boundaries. The nomenclature applies to the geographic area, not to any single company. For additional information on the integrations, their timing and their impact on the footprint of the PJM service territory, see the *2007 State of the Market Report*, Volume II, Appendix A, "PJM Geography."

Overview

Regulation Market

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 the issue is still under review by PJM members.[4] Both the *2006 State of the Market Report* and the *2007 State of the Market Report* have updated the analysis presented in that report.

Market Structure

- Supply. During 2007, the supply of offered and eligible regulation in PJM was generally both stable and adequate. Although PJM rules allow up to 25 percent of the regulation requirement to be satisfied by demand resources, none qualified to make regulation offers in 2007. The ratio of eligible regulation offered to regulation required averaged 1.90 throughout 2007.

- Demand. PJM calculates the regulation requirement each day for the entire day using 1.0 percent of the forecast-peak load for its control area. This requirement was established in August 2006. Because it is a function of peak load, the regulation requirement is seasonal. The average hourly regulation demand in 2007 was 967 MW. For the winter the demand was 956 MW; for the spring it was 913 MW; for the summer it was 1,089 MW; and for the fall it was 911 MW.

- Market Concentration. During 2007, the PJM Regulation Market had a load-weighted, average Herfindahl-Hirschman Index (HHI) of 1281 which is classified as "moderately concentrated."[5] The minimum hourly HHI was 720 and the maximum hourly HHI was 2547. The largest hourly market share in any single hour was 43 percent, and 56 percent of all hours had a maximum market share greater than 20 percent. In 2007, 80 percent of hours had three or fewer pivotal suppliers. The MMU concludes from these results that the PJM Regulation Market in 2007 was characterized by structural market power in 80 percent of the hours.

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 two dominant suppliers, whose offers are capped at marginal cost plus $7.50 per MWh plus LOC. All suppliers are paid the market-clearing price.

4 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).

5 See the *2007 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 Herfindahl-Hirschman Index (HHI).

Market Performance

- Price. For the PJM Regulation Market during 2007 the load-weighted, average price per MWh (i.e., the regulation market-clearing price, including LOC) associated with meeting PJM's demand for regulation was $36.86. This represents an increase of $4.17 from the average price for regulation during 2006. In 2007, 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 26 percent of all hours.

Synchronized Reserve Market

In February 2007, PJM restructured the Synchronized Reserve Market.[6] Throughout 2006 and for January 2007, PJM had four zonal Synchronized Reserve Markets: the PJM Mid-Atlantic Region, the ComEd Control Zone, the PJM Western Region and the PJM Southern Region. On February 1, 2007, the PJM Mid-Atlantic Region, the ComEd Control Zone and the PJM Western Region were combined into one market called the RFC Synchronized Reserve Zone. The PJM Southern Region became the Southern Synchronized Reserve Zone. The RFC Synchronized Reserve Zone is governed by the reliability requirements of the Reliability*First* Corporation. The Southern Synchronized Reserve Zone (Dominion) reliability requirements are set by the Southeastern Electric Reliability Council (SERC).

Market Structure

- Supply. During January 2007, the offered and eligible excess supply ratio was 1.28 for the PJM Mid-Atlantic Synchronized Reserve Region and the ratio was 1.24 for the ComEd Synchronized Reserve Control Zone.[7] During February to December 2007, the offered and eligible excess supply ratio was 1.81 for the RFC Synchronized Reserve Zone and the ratio was 1.25 for the Mid-Atlantic Subzone of the RFC Synchronized Reserve Zone. 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 2007, the MW contribution of DSR resources to the Synchronized Reserve Market had become significant.

- Demand. The average synchronized reserve requirements were: 1,300 MW for the RFC Synchronized Reserve Zone and 1,160 MW for the Mid-Atlantic Subzone. For the Southern Synchronized Reserve Zone, the requirement was usually 0 MW. 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 Tier 2 synchronized reserve in the Mid-Atlantic Subzone of the RFC Synchronized Reserve Zone was 184 MW. The average demand for Tier 2 synchronized reserve in the Southern Synchronized Reserve Zone was 4 MW.

6 In PJM, the term, Synchronized Reserve Market, is used to refer only to Tier 2 synchronized reserve.

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

- Market Concentration. In 2007, market concentration was high in the Tier 2 Synchronized Reserve Markets. The average cleared Synchronized Reserve Market HHI for the Mid-Atlantic Subzone of the RFC Synchronized Reserve Zone throughout 2007 was 4151. The largest hourly market share was 100 percent and 76 percent of all hours had a maximum market share greater than 40 percent. In the Mid-Atlantic Subzone of the RFC Synchronized Reserve Market, in 2007, 58 percent of hours had three or fewer pivotal suppliers. The MMU concludes from these results that the PJM Synchronized Reserve Markets in 2007 were characterized by structural market power.

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 merit-order 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 in the Mid-Atlantic Subzone of the RFC Synchronized Reserve Market was $16.28 per MW in 2007, a $1.71 per MW increase from 2006.

- Price and Cost. There was a significant change in the operation of the Synchronized Reserve Market in the last quarter of 2007 as PJM relied less on the market and more on out-of-market purchases of spinning reserve for local needs. The increase in out-of-market purchases indicates that the Synchronized Reserve Market is not functioning to coordinate supply and demand. It is not clear why the additional synchronized reserve requirements cannot be procured via the market. If these requirements cannot be procured via the market, it is not clear why the out-of-market purchase of spinning reserve resources for local issues should not be treated as operating reserve charges. While the creation of the Synchronized Reserve Market for the entire RFC Zone suggested that there is a single, geographic market, the actual results are not consistent with that view.

- DSR. Demand-side resources began participating in the Synchronized Reserve Markets in August 2006. Participation of demand response grew significantly in 2007. Not only did more participants offer DSR, but demand response was generally less expensive than other forms of synchronized reserve. In 19 percent of hours during 2007 in which a Tier 2 Synchronized Reserve Market was cleared for the Mid-Atlantic Subzone, all synchronized reserve was provided by DSR.

- Availability. A synchronized reserve deficit occurs when the combination of Tier 1 and Tier 2 synchronized reserve is not adequate to meet the synchronized reserve requirement. Neither PJM Synchronized Reserve Market experienced deficits during 2007.

Conclusion

PJM consolidated its Regulation Markets into a single Combined Regulation Market, on a trial basis, effective August 1, 2005. The MMU has consistently found since that time that the PJM Regulation Market is characterized by structural market power. This conclusion is based on the results of the three pivotal supplier test. In addition, in 2007, as in 2006, the MMU cannot conclude that the Regulation Market produced competitive results or noncompetitive results, based on the MMU analysis of the relationship between the offer prices and marginal costs of units that set the price in the Regulation Market, the marginal units. The MMU's reliance on estimates of regulation costs 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.

The MMU has also consistently concluded that PJM's consolidation of its Regulation Markets had 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.[8, 9] This conclusion holds true for the 2007 Regulation Market. 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, 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.[10]

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 two 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, two 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 structure of each Synchronized Reserve Market has been evaluated and the MMU has concluded that these markets are not structurally competitive as they are characterized by high levels of supplier

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

9 *2006 State of the Market Report* (March 8, 2007), p. 247.

10 See the *2007 State of the Market Report*, Volume II, Appendix L, "Three Pivotal Supplier Test."

concentration and inelastic demand. (The term, Synchronized Reserve Market, refers only to Tier 2 synchronized reserve.) 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 RFC Synchronized Reserve Zone and in the Southern Synchronized Reserve Zone 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.

There was a significant change in the operation of the Synchronized Reserve Market in the last quarter of 2007 as PJM relied less on the market and more on out-of-market purchases of spinning reserve for local needs. Beginning in October and increasing substantially in November and December, there was an increase in the amount of combustion-turbine-based, synchronized condenser MW added by PJM market operations to the Synchronized Reserve Market after market clearing. MW added after the market cleared accounted for more than 50 percent of total synchronized reserve MW purchased in December.

The increase in out-of-market purchases indicates that the Synchronized Reserve Market is not functioning to coordinate supply and demand. It is not clear why the additional synchronized reserve requirements cannot be procured via the market. If these requirements cannot be procured via the market, it is not clear why the out-of-market purchase of spinning reserve resources for local issues should not be treated as operating reserve charges. While the creation of the Synchronized Reserve Market for the entire RFC Zone suggested that there is a single, geographic market, the actual results are not consistent with that view.

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 cost. 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.

Regulation Market

Market Structure

The market structure of the 2007 PJM Regulation Market remained similar to the market structure of the 2006 Regulation Market. DSR participation was introduced in 2006, but demand-side resources did not qualify and make offers in the Regulation Market in either 2006 or 2007.

Supply

The supply of regulation can be measured as regulation capability, regulation offered, or regulation offered and eligible. For purposes of evaluating the Regulation Market, the relevant regulation supply is the level of supply that is both offered to the market on an hourly basis and is eligible to participate in the market on an hourly basis. This is the only supply that is actually considered in the determination of market prices. The level of supply that clears in the market on an hourly basis is called assigned regulation or cleared regulation. Assigned regulation is selected from regulation that is both offered and eligible.

Regulation capability is the sum of the maximum daily offers for each unit and is a measure of the total volume of regulation capability as reported by resource owners.

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

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

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

The average eligible regulation supply-to-requirement ratio in the PJM Regulation Market during 2007 was 1.90. Even during periods of diminished supply such as off-peak hours, eligible regulation supply was adequate to meet the regulation requirement.

Demand

Demand for regulation does not change with price, i.e. demand is price inelastic. The demand for regulation is set administratively based on reliability objectives and forecast load. Regulation demand is also referred to in the *2007 State of the Market Report* as "required regulation."

The PJM regulation requirement was set by Reliability*First* Corporation in August 2006 to be 1.0 percent of the forecast-peak load for the entire day.[11] During 2007 the PJM regulation requirements ranged from 709 MW to 1,390 MW. The average required regulation was 967 MW.

Market Concentration

Market Structure Definitions

The market structure analysis follows the FERC logic specified in the AEP Order.[12] The logic of the delivered price test is followed by calculating market share, HHI and pivotal supplier metrics for each market configuration.[13] The analysis presented here differs in two ways from the FERC's delivered price test. The delivered price test would start with the universe of regulation offered and eligible and then limit the analysis to the relevant competitive offers, defined as those offered and eligible units that could provide regulation at less than, or equal to, 1.05 times the clearing price. The analysis here also includes separately a broader definition of the relevant competitive offers, defined as those offered and eligible units that could provide regulation at less than, or equal to, 1.5 times the clearing price. In addition, the analysis here includes the results of the one and the three pivotal supplier tests. In all cases, regulation must be both offered and eligible in an hour in order for it to be part of the market. This is termed economic capacity under the delivered price test.

The delivered price test may also be applied using available economic capacity, defined as gross supply by participants net of their load obligation. The fact that suppliers have load obligations may affect their incentives to exercise market power although not unambiguously. However, as the amount of load that will be served by the integrated utilities in the future is unknown given the unknown extent of retail competition, a reasonable approach is to evaluate the entire regulation supply, or economic capacity, as is done here.

The FERC's AEP Order indicates that failure of any one of the specified tests is adequate for a showing of market power including tests based on market concentration, market share and pivotal supplier analyses. The analysis presented here goes further in order to analyze the significance of excess supply. The MMU applies the pivotal supplier test using one and three pivotal suppliers. In addition, when there are hours with one or three pivotal suppliers, the analysis also examines the frequency with which individual generation owners are in the pivotal group. If the hours that fail a pivotal supplier test have the same pivotal supplier(s) for a significant proportion of the hours, that information can be used to identify dominant suppliers.

11 See Reliability*First* Corporation < http://www.rfirst.org/> .

12 107 FERC ¶ 61,018 (2004) (AEP Order) and 108 FERC ¶ 61,026 (2004) (AEP Order on Rehearing).

13 AEP Order at 105 et seq.

The pivotal supplier test represents an analytical approach to the issue of excess supply. Excess supply, by itself, is not adequate to ensure a competitive outcome. A monopolist could have substantial excess supply, but the monopolist would not be expected to change its market behavior as a result. The same logic applies to a small group of dominant suppliers. However, if there is adequate supply without the three dominant suppliers to meet the demand, then the market can reasonably be deemed competitive.

PJM Regulation Market

During 2007 the PJM Regulation Market total capability was 7,609 MW.[14] Total capability is a theoretical measure which is never actually achieved. The level of regulation resources offered on a daily level and the level of regulation resources both offered and eligible to participate on an hourly level in the market were lower than the total regulation capability. In 2007 the average daily offer level was 3,911 MW or 51 percent of total capability while the average hourly eligible offer level was 1,835 MW or 24 percent of total capability. Although regulation is offered daily, eligible regulation changes hourly. Typically less regulation is eligible to be assigned during off-peak hours because fewer steam units are running during those hours. Table 6-1 shows capability, daily offer and average hourly eligible MW for all hours as well as for off-peak and on-peak hours.

Table 6-1 PJM regulation capability, daily offer and hourly eligible: Calendar year 2007

Period	Regulation Capability (MW)	Average Daily Offer (MW)	Percent Of Capability Offered	Average Hourly Eligible (MW)	Percent Of Capability Eligible
All hours	7,609	3,911	51%	1,835	24%
Off peak	7,609	NA	NA	1,575	21%
On peak	7,609	NA	NA	2,118	28%

The ratio of the hourly regulation supply offered and eligible to the hourly regulation requirement averaged 1.90 for PJM during 2007. When this ratio equals 1.0, it indicates that offered supply exactly equals demand for the referenced time period.

Hourly HHI values were calculated based on cleared regulation. HHI values ranged from a maximum of 2547 to a minimum of 720, with an average value of 1281 which is defined as moderately concentrated by the FERC definitions. Table 6-2 summarizes the 2007 PJM Regulation Market HHIs.

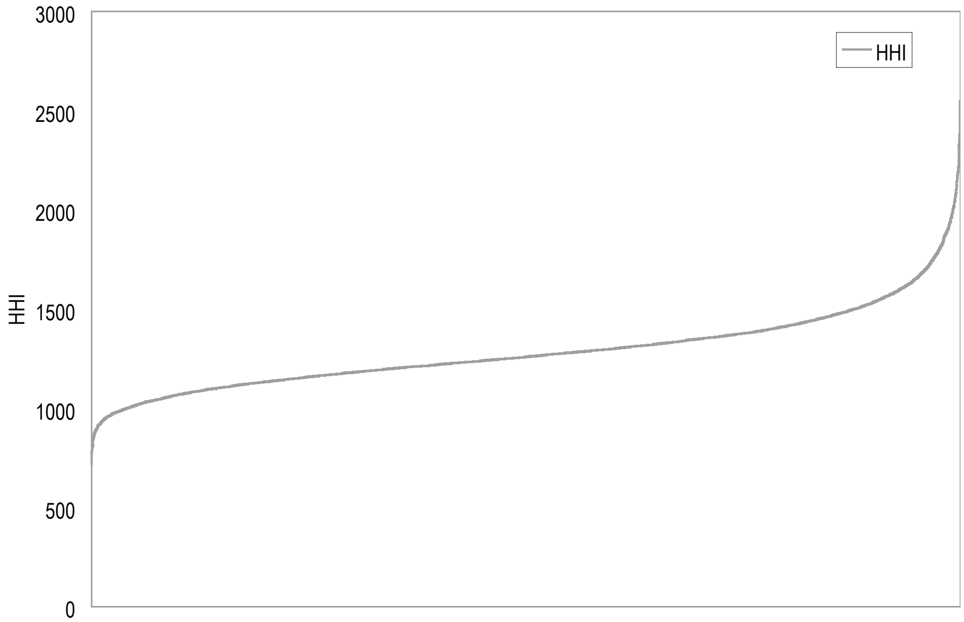
Table 6-2 PJM cleared regulation HHI: Calendar year 2007

Market Type	Minimum	Load-Weighted Average	Maximum
Cleared regulation	720	1281	2547

14 Total offer capability is defined as the sum of the maximum daily offer volume for each offering unit during the period, without regard to the actual availability of the resource or to the day on which the maximum was offered.

The PJM Regulation Market exhibited consistent moderate market concentration with about 4.1 percent of the periods with an HHI less than 1000 and about 2.4 percent of the periods with an HHI greater than 1800. See the HHI duration curve in Figure 6-1.

Figure 6-1 PJM Regulation Market HHI: Calendar year 2007



The largest hourly market share for cleared regulation was 43 percent, and 56 percent of all hours had a maximum market share greater than 20 percent. Although most hours had a market participant with a market share greater than 20 percent, the highest annual average hourly market share by a company was 16 percent. Annual average hourly market shares for cleared regulation in 2007 are listed in Table 6-3.

Table 6-3 Highest annual average hourly Regulation Market shares: Calendar year 2007

Company Market Share Rank	Cleared Regulation Top Market Shares
1	16%
2	13%
3	12%

When all eligible regulating units whose price is less than, or equal to, the regulation market-clearing price (RMCP) times 1.05 are included in the definition of the relevant market, 68 percent of hours failed the one pivotal supplier test during 2007. (See Table 6-4.) This means that for 68 percent of hours the total regulation requirement could not be met in the absence of the largest supplier. One supplier of regulation was pivotal in 88 percent of the hours with one pivotal supplier; a second company was pivotal in 74 percent of hours with one pivotal supplier, and a third company was pivotal in 73 percent of hours when there was one pivotal supplier. Ninety-four percent of hours failed the three pivotal supplier test. One supplier of regulation was pivotal in 90 percent of the three pivotal supplier hours and two other companies were pivotal in 76 percent of three pivotal supplier hours.

Table 6-4 Regulation Market pivotal suppliers: Calendar year 2007

	Hours with One Pivotal Supplier (Percent)	Hours with Three Pivotal Suppliers (Percent)
Price ≤ RMCP • 1.05	68%	94%
Price ≤ RMCP • 1.5	14%	80%

When all eligible regulating units whose price is less than, or equal to, the market-clearing price times 1.5 are included in the definition of the relevant market, 14 percent of hours failed the one pivotal supplier test during 2007. (See Table 6-4.) Eighty percent of hours failed the three pivotal supplier test. One company was pivotal in 92 percent of those hours; a second company was pivotal in 80 percent, and a third company was pivotal in 76 percent of three pivotal supplier hours. Thus, in addition to failing the relevant pivotal supplier tests in a significant number of hours, the pivotal suppliers in the Regulation Market were the same suppliers in the majority of hours when the test was failed. This is a further indication that the structural market power issue in the Regulation Market remained persistent and repeated during 2007.[15]

The MMU concludes from these results that the PJM Regulation Market in 2007 was characterized by structural market power. This conclusion is based on the pivotal supplier results and, in particular, on the results of the three pivotal supplier test with a market definition that includes all offers with a price less than, or equal to, 1.50 times the market-clearing price.

Market Conduct

Offers

Generators wishing to participate in the PJM Regulation Market must submit regulation offers for specific units by 1800 Eastern Prevailing Time (EPT) of the day before the operating day. 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. As in any competitive market, regulation offers at marginal cost are considered to be competitive. In PJM, a $7.50-per-MWh adder is considered to be consistent with competitive offers based on an analysis of historical offer behavior.

15 See the *2006 State of the Market Report*, Section 6, "Ancillary Services," p. 248.

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

PJM's Regulation Market is cleared hourly, based on both offers submitted by the units and the hourly lost opportunity cost of each unit, calculated based on the forecast LMP at the location of each regulating unit.[16] The total offer price is the sum of the unit-specific offer and the opportunity cost. In order to clear the market, PJM ranks all offered and eligible regulating resources in ascending total offer price order; it does the same for synchronized reserve and simultaneously determines the least expensive set of resources necessary to provide regulation, synchronized reserve and energy for the operating hour, taking into account any resources self-scheduled to provide any of these services. The Regulation Market price that results is the RMCP, and the unit that sets this price is the marginal unit.

In 2007, offers from some regulation suppliers exceeded the competitive level. The competitive offer level for regulation, as for any other market, is the marginal cost of providing regulation. For the PJM Regulation Market, the marginal cost has been defined as the calculated cost plus a margin of $7.50 per MW. The cost of providing regulation has not been provided by suppliers. While the MMU recommended that the provision of such data be required and the PJM systems were created to allow the provision of cost data, provision of the data is not mandatory and suppliers do not currently provide the data. In April 2007, the Cost Development Task Force (CDTF) proposed adjusting the formulas used to calculate regulating unit costs.[17] The new rules allow units which have been regulating for less than 10 years to add variable operating and maintenance (VOM) costs according to unit type. These adjustments have increased the variable operating and maintenance costs some units are permitted to use, thus decreasing the percentage of bids which exceed the allowable $7.50 plus costs in 2007 from the 33 percent in 2006. Using the proposed CDTF guidelines, the MMU estimated hourly marginal costs for units that provided regulation during 2007.[18] Based on those estimates, 26 percent of marginal unit daily offers exceeded marginal costs.

16 PJM estimates the opportunity cost for units providing regulation based on a forecast of locational marginal price (LMP) for the upcoming hour. Opportunity cost is included in the market-clearing price.

17 See PJM Cost Development Task Force < http://www.pjm.com/committees/task-forces/cdtf/postings/20070416-regulation-redline.pdf > (56 KB).

18 See PJM. "Manual 15: Cost Development Guidelines," Revision 8 (October 16, 2007), p. 40.

Market Performance

Price

Figure 6-2 shows the daily average regulation market-clearing price and the opportunity cost component for the marginal units in the PJM Regulation Market. All units chosen to provide regulation received as payment the higher of the clearing price multiplied by the unit's assigned regulating capability, or the unit's regulation offer multiplied by its assigned regulating capability plus the individual unit's real-time opportunity cost.[19]

In 2007, offers at levels greater than the competitive level set the clearing price for regulation in 26 percent of hours.[20] Seventeen percent of hours were between $0 and $7.50 per MW above the competitive level; 1 percent of hours were between $7.50 and $10 per MW above the competitive level; and 7 percent of hours were greater than $10 per MW above the competitive level. To put these results in context, the load-weighted, average offer price for all marginal units in the PJM Regulation Market during 2007 was $12.06, so an additional $7.50 per MW is a markup of approximately 62 percent. These results mean that the MMU cannot conclude that the Regulation Market results were competitive in 2007 or that the Regulation Market results were noncompetitive. The absence of a definitive conclusion is a result of the fact that the cost data are based on MMU estimates rather than data submitted by market participants. The MMU recommends that market participants be required to submit the cost of regulation, consistent with the definitions in PJM's "Cost Development Guidelines," when daily regulation offers are submitted in order both to permit analysis and to permit the recommended defined, targeted mitigation.[21]

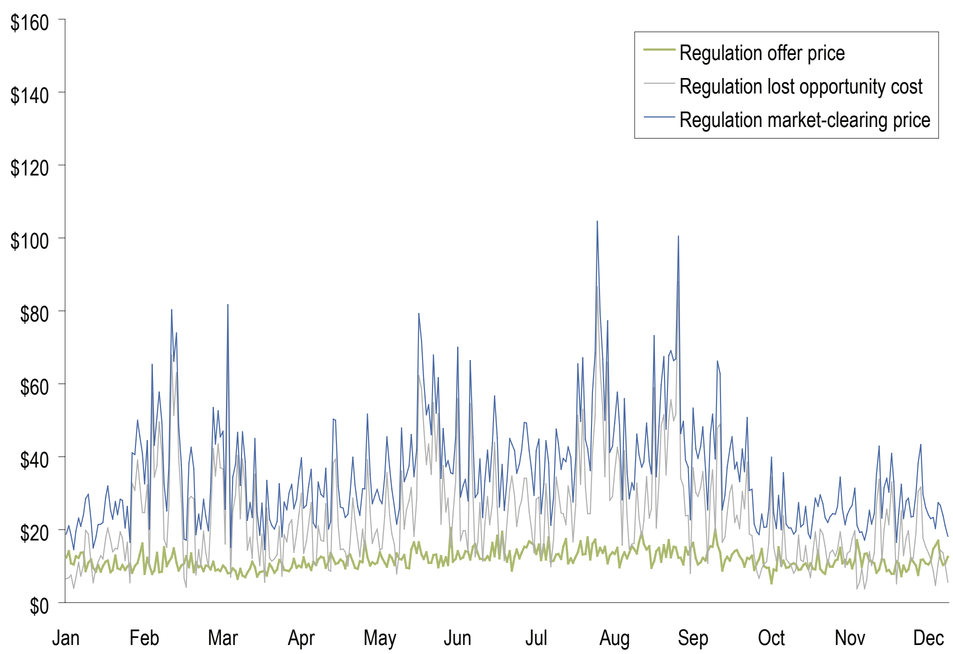
19 See PJM. "Manual 28: Operating Agreement, Accounting," Revision 39, Section 4, "Regulation Credits" (January 1, 2008), pp. 27-28. PJM uses estimated opportunity cost to clear the market and real-time opportunity cost to compensate generators that provide regulation and synchronized reserve. Real-time opportunity cost is calculated using real-time LMP.

20 The percent of hours in which the offer of the marginal unit exceeded marginal cost is slightly less than the percent of offers of marginal units exceeding marginal cost because there can be multiple marginal units in an hour.

21 See PJM. "Manual 15: Cost Development Guidelines," Revision 8 (October 16, 2007).

Regulation credits are awarded to generation owners that have either self-scheduled or sold regulation into the market. Regulation credits for units self-scheduled to provide regulation are equal to the RMCP times the unit's self-scheduled regulating capability. Regulation credits for units that offer regulation into the market and are selected to provide regulation are the higher of the RMCP times the unit's assigned regulating capability, or the unit's regulation offer times its assigned regulating capability plus the opportunity cost that the unit has incurred. Although most units are paid RMCP times their assigned regulation MW, a substantial portion of the RMCP is the LOC, based on forecast LMP calculated for the marginal unit during market clearing. This means that a substantial portion of the total cost of regulation is determined by LOC. As shown in Figure 6-2, more than half of the regulation price is the LOC of the marginal unit. The balance of the RMCP is the unit's regulation offer. The load-weighted, average offer of the marginal unit for the PJM Regulation Market during 2007 was $12.06 per MW. The load-weighted, average LOC of the marginal unit for the PJM Regulation Market during 2007 was $24.85. In the PJM Regulation Market the marginal unit LOC averaged 67 percent of the RMCP.

Figure 6-2 PJM Regulation Market daily average market-clearing price, lost opportunity cost and offer price (Dollars per MW): Calendar year 2007

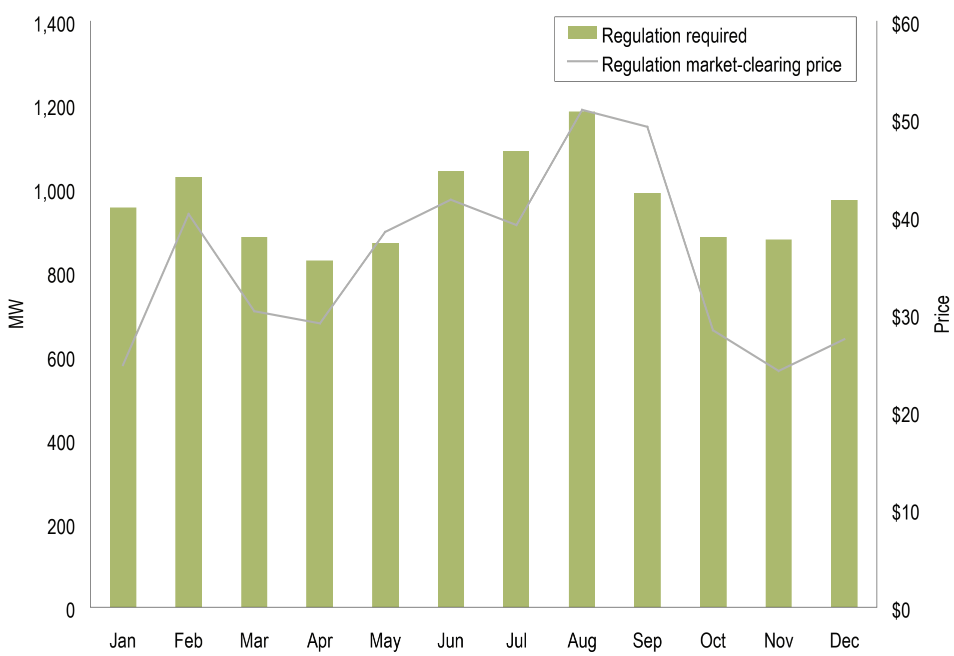


On a shorter-term basis, regulation prices follow daily and weekly patterns. The supply of regulation is most plentiful between 0600 and 2300 EPT, Monday through Friday.

During weekends and North American Electric Reliability Council (NERC) holidays, and weekdays between the hour ending at 2400 until the hour ending at 0700 (i.e., the off-peak hours), fewer steam generators are running and available to regulate. At times, units must be kept running for regulation that are not economic for energy, resulting in an increase in the LOC portion of the clearing price. At other times, expensive combustion turbine generators must be started to meet regulation requirements.

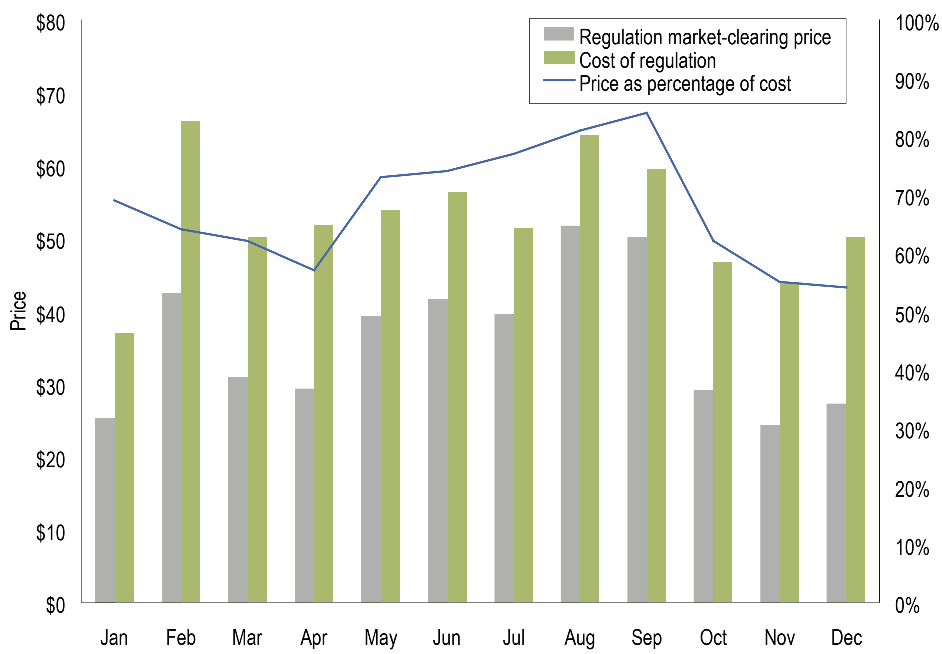
Figure 6-3 shows the level of demand for regulation by month in 2007 and the corresponding level of regulation price. The data show a correlation between price and demand.

Figure 6-3 Monthly average regulation demand (required) vs. price: Calendar year 2007



Units which provide regulation are paid the higher of the RMCP or their offer plus their unit-specific opportunity cost. The offer plus the unit-specific opportunity cost may be higher than the RMCP for a number of reasons. If real-time LMP is greater than the LMP forecast prior to the operating hour and included in the RMCP, unit-specific opportunity costs will be higher than forecast. Such higher LMPs can be local, because of congestion, or more general, if system conditions change. Other reasons include units that must be redispatched because of constraints or unanticipated unit performance problems. When some units are paid more than the RMCP based on unit-specific lost opportunity costs, the result is that PJM's regulation charge per MWh is higher than the RMCP. Figure 6-4 compares the regulation charge per MWh with the regulation-clearing price to show the difference between the price of regulation and the total charge for regulation.

Figure 6-4 Monthly load-weighted, average regulation cost and price: Calendar year 2007



For all of 2007, the load-weighted, average regulation price was $36.86. The average regulation charge was $52.91. The difference between the Regulation Market price and the actual charge for regulation remained significant in 2007. The charge for regulation was 43.5 percent higher than the market price of regulation. The payment of a large portion of regulation charges on a unit-specific basis rather than on the basis of a market-clearing price remains a cause for concern as it results in a weakened market-price signal to the providers of regulation.

Synchronized Reserve Market

Market Structure

The PJM Synchronized Reserve Market was restructured in 2007. The Mid-Atlantic Region's Synchronized Reserve Market, the Western Region's Synchronized Reserve Market, and the ComEd Control Zone's Synchronized Reserve Market were combined into a single market called the RFC Synchronized Reserve Zone. Reliability requirements for the RFC Synchronized Reserve Zone are set by the Reliability*First* Corporation. The Southern Region's Synchronized Reserve Market remains a separate market. It falls under the reliability requirements of SERC and is referred to as the Southern Synchronized Reserve Zone.

Supply

Synchronized reserve is an ancillary service defined as generation or curtailable load that is synchronized to the system and capable of producing output or shedding load within 10 minutes. Synchronized reserve can, at present, be provided by a number of resources, including steam units with available ramp, condensing hydroelectric units, condensing combustion turbines (CTs) and CTs running at minimum generation. Synchronized reserve can also be supplied by DSR resources subject to the limit that they provide no more than 25 percent of the total synchronized reserve requirement. Synchronized reserve DSR resources can be provided by behind-the-meter generation or by load reductions.

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

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

Under Synchronized Reserve Market rules, Tier 2 synchronized reserve resources are paid to be available as synchronized reserve, regardless of whether the units are called upon to generate in response to a spinning event and are subject to penalties if they do not provide synchronized reserve when called. The price for Tier 2 synchronized reserve is determined in a market for Tier 2 synchronized reserve resources. This market is termed the Synchronized Reserve Market. Several steps are necessary before the hourly

22 See PJM. "Manual 11: Balancing Operations," Revision 32 (September 28, 2007), p. 39.

Synchronized Reserve Market is cleared. Ninety minutes prior to the start of the hour, PJM estimates the amount of Tier 1 reserve available from every unit; 60 minutes prior to the start of the hour, self-scheduled Tier 2 units are identified. If synchronized reserve requirements are not met by Tier 1 and self-scheduled Tier 2 resources, then a Tier 2 clearing price is determined at least 30 minutes prior to the start of the hour. This Tier 2 price is equivalent to the merit-order price of the highest-priced, Tier 2 resource needed to meet the demand for synchronized reserve requirements, the marginal unit, based on the simultaneous clearing of the Regulation Market and the Synchronized Reserve Market.[23]

The synchronized reserve offer price submitted for a unit can be no greater than the unit's incremental operating and maintenance cost plus a $7.50 per MWh margin.[24, 25] The market-clearing price is comprised of the marginal unit's synchronized reserve offer price, the cost of energy use, the startup cost (if the unit is not running) and the unit's lost opportunity cost. LOC is calculated by PJM based on forecast LMPs and generation schedules from the unit dispatch system. LOC for demand-side resources is always zero. All units cleared in the Synchronized Reserve Markets are paid the higher of either the market-clearing price or the unit's synchronized reserve offer plus the unit-specific LOC and the cost of energy use incurred.

The Tier 2 Synchronized Reserve Market in each of PJM's synchronized reserve areas is cleared on cost-based offers because the structural conditions for competition do not exist. The market structure issue can be even more severe when the Synchronized Reserve Market becomes local because of transmission constraints.

During January 2007, the offered and eligible excess supply ratio was 1.28 for the PJM Mid-Atlantic Synchronized Reserve Region and the ratio was 1.24 for the ComEd Synchronized Reserve Control Zone.[26] For the RFC Synchronized Reserve Zone during February through December 2007, the offered and eligible excess supply ratio was 1.81. Within the Mid-Atlantic Subzone of the RFC Synchronized Reserve Zone, the offered and eligible excess supply ratio was 1.25.[27] These excess supply ratios are determined using the administratively established requirement for synchronized reserve. Actual market demand for Tier 2 synchronized reserve is lower than the synchronized reserve requirement because a significant amount of Tier 1 synchronized reserve is usually available.

Demand

The market demand for Tier 2 synchronized reserve is determined by subtracting the amount of forecast Tier 1 synchronized reserve available from each synchronized reserve zone's synchronized reserve requirement for the period. The total synchronized reserve requirement is different for the two Synchronized Reserve Markets. The synchronized reserve requirement is determined at the discretion of PJM after careful review to ensure appropriate system reliability and to maintain compliance with applicable NERC and regional reliability organization requirements. RFC and Dominion reserve requirements are determined on at least an annual basis. Mid-Atlantic Subzone requirements are established on a seasonal basis, recognizing potential deliverability issues.[28]

23 Although it is unusual, a PJM dispatcher can deselect units which have been committed after the clearing price has been established. This only happens if real-time system conditions require dispatch of a spinning unit for constraint control, or problems with a generator or monitoring equipment are reported.

24 See PJM. "Manual 11: Balancing Operations," Revision 32 (September 28, 2007), p. 41.

25 See PJM. "Manual 15: Cost Development Guidelines," Revision 8 (October 16, 2007), p. 37.

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

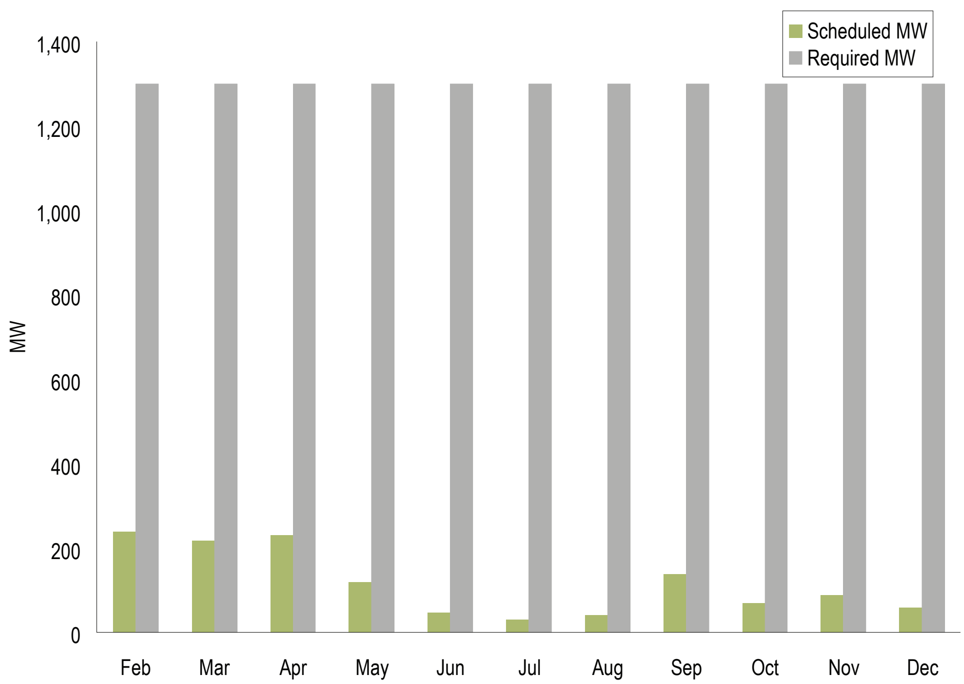
27 The Synchronized Reserve Market in the PJM Southern Region cleared in so few hours that related data for that market are not meaningful.

28 See PJM. "Manual 10: Pre-Scheduling Operations," Revision 22 (May 15, 2007), p. 21.

Currently the RFC synchronized reserve requirement is the greater of the Reliability*First* Corporation's imposed minimum requirement or the system's largest contingency. The actual synchronized reserve requirement for the RFC Zone for February through December 2007 was always 1,300 MW.

Figure 6-5 shows the average monthly synchronized reserve required and the average monthly Tier 2 synchronized reserve MW scheduled during 2007 for the RFC Synchronized Reserve Market.[29]

Figure 6-5 RFC Synchronized Reserve Zone monthly required vs. scheduled: February through December 2007



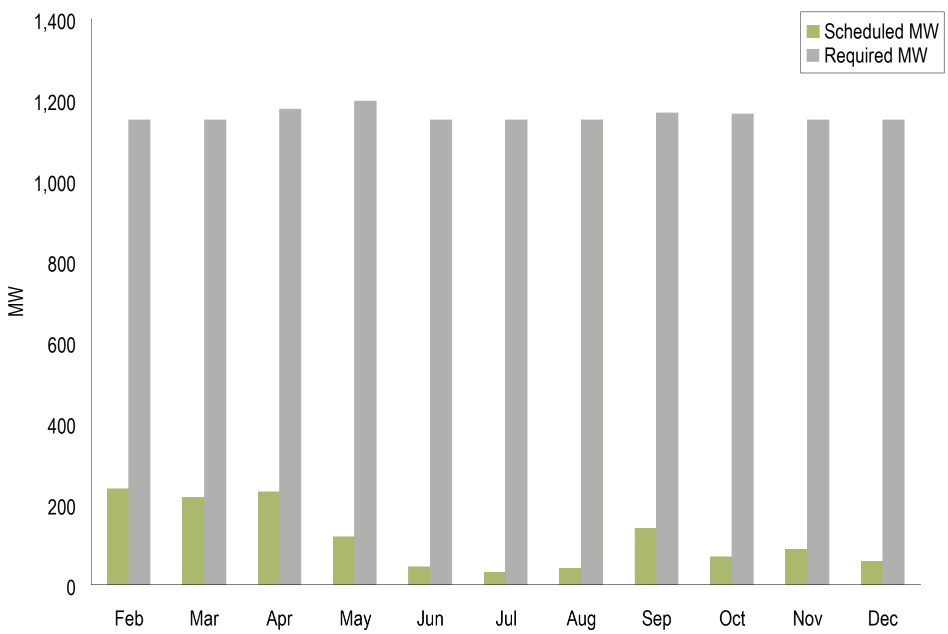
The RFC Synchronized Reserve Zone is large and some available Tier 1 must be physically located in the Mid-Atlantic Subzone as a result of transmission limits between the western and eastern portions of the zone. PJM calculates the available transfer capability of these limits. The calculation of Mid-Atlantic Subzone Tier 1 includes what is available in the east plus the amount of Tier 1 synchronized reserve in the west that can be transferred into the east.[30] As a result, there is frequently a Tier 2 synchronized reserve requirement only in the Mid-Atlantic Subzone. In this case, the Mid-Atlantic Subzone has a separate clearing price.

As a whole, the RFC Synchronized Reserve Zone almost always has enough Tier 1 to cover its synchronized reserve requirement. In 2007, the RFC Synchronized Reserve Zone cleared a Tier 2 Synchronized Reserve Market in less than 1 percent of all hours. The Mid-Atlantic Subzone of the RFC Synchronized Reserve Zone cleared a separate Tier 2 market during 60 percent of all hours. Figure 6-6 compares the required Tier 2 MW to the scheduled MW for the Mid-Atlantic Subzone only.

29 Figures 6-5 through 6-12 address the combined synchronized reserve markets (February 2007 through December 2007 only).

30 See PJM. "Manual 11: Scheduling Operations," Revision 32 (September 28, 2007), p. 45.

Figure 6-6 RFC Synchronized Reserve Zone, Mid-Atlantic Subzone synchronized reserve required vs. scheduled: February through December 2007



The actual synchronized reserve requirement for the Mid-Atlantic Subzone for February through December 2007 was usually 1,150 MW but there were several days in April, May, September and October on which those requirements were increased for reliability reasons related to temporary grid conditions.

The difference between the level of required synchronized reserve and the level of Tier 2 synchronized reserve scheduled is the amount of Tier 1 synchronized reserve available on the system.

A comparison of Figure 6-5 and Figure 6-6 shows that almost all Tier 2 Synchronized Reserve Market MW are Mid-Atlantic Subzone, Synchronized Reserve Market MW.

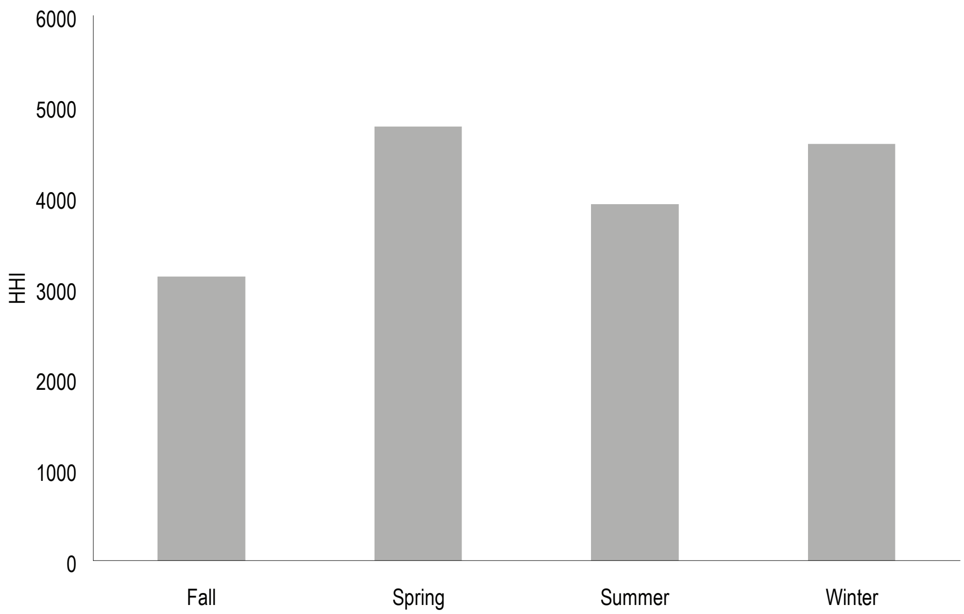
The Southern Synchronized Reserve Zone is part of the Virginia and Carolinas Area (VACAR) subregion of SERC. VACAR specifies that available, 15-minute quick start reserve can be subtracted from Dominion's share of the largest contingency to determine synchronized reserve requirements. The amount of 15-minute quick start reserve available in VACAR is sufficient to make Tier 2 synchronized reserve demand zero for most hours. The actual hourly Southern Synchronized Reserve Zone's synchronized reserve requirement was usually zero because Dominion's share of the largest contingency within VACAR was offset by its quick start capability. On average, the hourly synchronized reserve requirement in Dominion was 4 MW.

Market Concentration

The Tier 2 Synchronized Reserve Market is the only Synchronized Reserve Market cleared by PJM. Although the RFC Tier 2 Synchronized Reserve Market was less concentrated in 2007 than the four PJM Tier 2 Synchronized Reserve Markets had been in 2006, the 2007 RFC Synchronized Reserve Market remains highly concentrated and dominated by a relatively small number of companies.

The HHI for the Mid-Atlantic Subzone of the 2007 RFC Synchronized Reserve Market was 4151, which is defined as highly concentrated. (See Figure 6-7 which also provides seasonal details.)

Figure 6-7 Cleared Mid-Atlantic Subzone RFC Tier 2 Synchronized Reserve Market seasonal HHI: February through December 2007



The largest hourly market share was 100 percent and 76 percent of all hours had a maximum market share greater than 40 percent. In 1 percent of Mid-Atlantic Subzone hours during which a market was cleared between February and December 2007 a single company had 100 percent of the market share. The highest annual average market share was 26 percent. (See Table 6-5.)

Table 6-5 The Mid-Atlantic Subzone of the PJM RFC Tier 2 Synchronized Reserve Market's cleared market shares: February through December 2007

Company Market Share Rank	Cleared Synchronized Reserve: All Units
1	26%
2	18%
3	8%
4	7%
5	4%

The pivotal supplier metric provides an analytical approach to the issue of excess supply.[31] (See Table 6-6.)

Table 6-6 The Mid-Atlantic Subzone RFC Tier 2 Synchronized Reserve Market percent pivotal supplier hours: February through December 2007

	Hours with One Pivotal Supplier (Percent)	Hours with Three Pivotal Suppliers (Percent)
Price ≤ RMCP • 1.05	41%	87%
Price ≤ SRMCP • 1.5	10%	58%

When the relevant market was defined to include all offers at less than, or equal to, 1.05 times the clearing price, there was a single pivotal supplier in 41 percent of the hours and three pivotal suppliers in 87 percent of the hours.

When the relevant market is defined to include all offers at less than, or equal to, 1.5 times the clearing price in the Mid-Atlantic Subzone of the RFC Synchronized Reserve Market, there was a single pivotal supplier in 10 percent of the hours and three pivotal suppliers in 58 percent of the hours. One company was pivotal in 73 percent of three pivotal supplier hours and a second company was pivotal in 66 percent of those hours.

These results indicate that the Mid-Atlantic Subzone of the RFC Synchronized Reserve Market, the only synchronized reserve market that clears on a regular basis, is not structurally competitive.

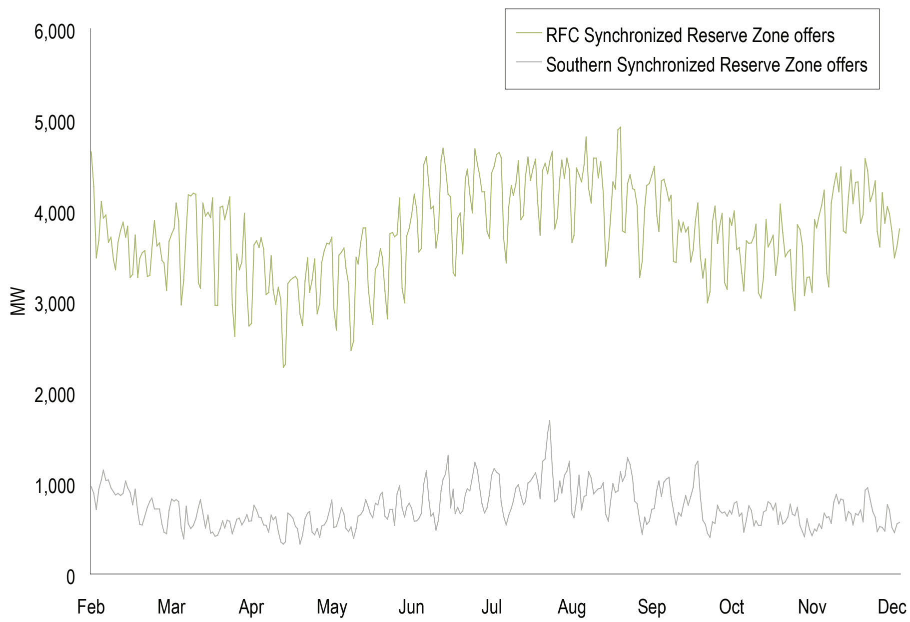
31 See the *2007 State of the Market Report*, Volume II, Appendix L, "Three Pivotal Supplier Test."

Market Conduct

Offers

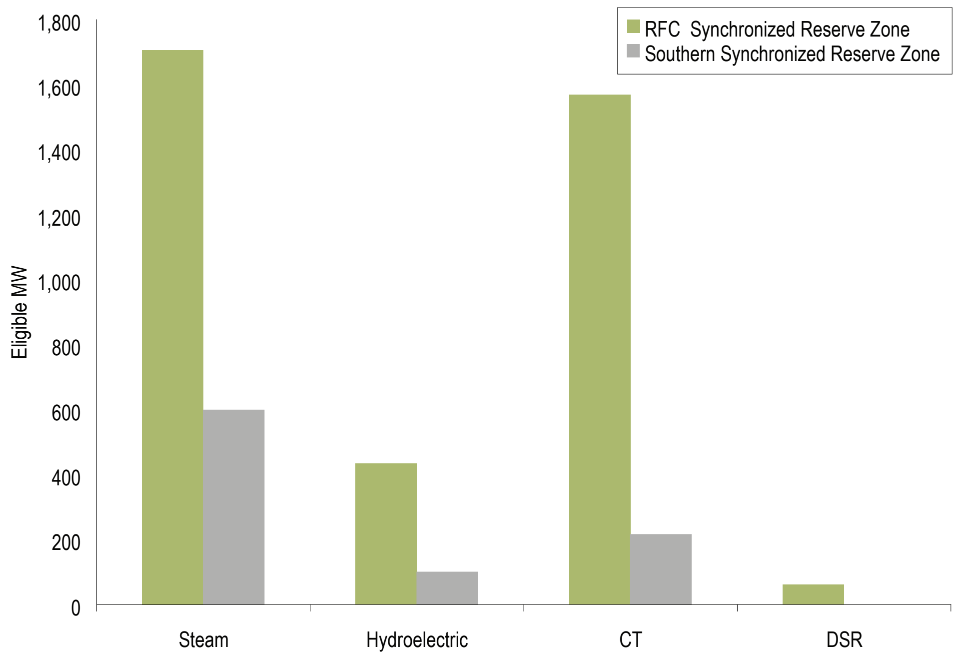
Figure 6-8 shows the daily average hourly eligible Tier 2 synchronized reserve offers. Eligible offer MW is dependent upon the offering unit being run. For that reason, the eligible offer volume shows weekly variability based on off-peak/on-peak operating cycles as well as seasonal variability.

Figure 6-8 Tier 2 synchronized reserve average hourly eligible volume (MW): February through December 2007



Synchronized reserve is offered by steam, CT, hydroelectric and DSR resources. Figure 6-9 shows average eligible MW volume by market and unit type.

Figure 6-9 Average daily Tier 2 synchronized reserve eligible by unit type (MW): February through December 2007



As of the end of 2007, the MW contribution of DSR resources to the Synchronized Reserve Market had become significant. In 2007, DSR supplied 19 percent of synchronized reserve MW cleared in the RFC Synchronized Reserve Zone. The DSR share of total synchronized reserve MW cleared grew throughout the year (See Figure 6-12) reaching 45 percent for the months of October, November and December. What are termed demand-side resources may at times be generation that is behind the meter.

Market Performance

Price

Figure 6-11 shows the load-weighted, average Tier 2 price (i.e., SRMCP • MW cleared) and the cost per MW associated with meeting PJM demand for synchronized reserve (i.e., total credits paid • MW purchased). The price of Tier 2 synchronized reserve is called the synchronized reserve market-clearing price (SRMCP). Resources which provide synchronized reserve are paid the higher of the SRMCP or their offer plus their unit-specific LOC. The offer plus the unit-specific LOC may exceed the SRMCP for a number of reasons. If real-time LMP is greater than the LMP forecast prior to the operating hour and included in the SRMCP, unit-specific LOC will be higher than forecast. Such higher LMPs can be local because of congestion or more general if system conditions change. The additional costs of noneconomic dispatch are added to the total cost of synchronized reserve. When some units are paid the value of their offer plus their unit-specific LOC, the result is that PJM's synchronized reserve cost per MWh is higher than the SRMCP.

The RFC Synchronized Reserve Market cleared as a single market for only 10 hours in 2007. The only significant Synchronized Reserve Market was in the Mid-Atlantic Subzone of the RFC Synchronized Reserve Market. The load-weighted, average price for synchronized reserve in the Mid-Atlantic Subzone of the RFC Synchronized Reserve Market during 2007 was $16.28 while the corresponding cost of synchronized reserve was $21.32.

Price and Cost

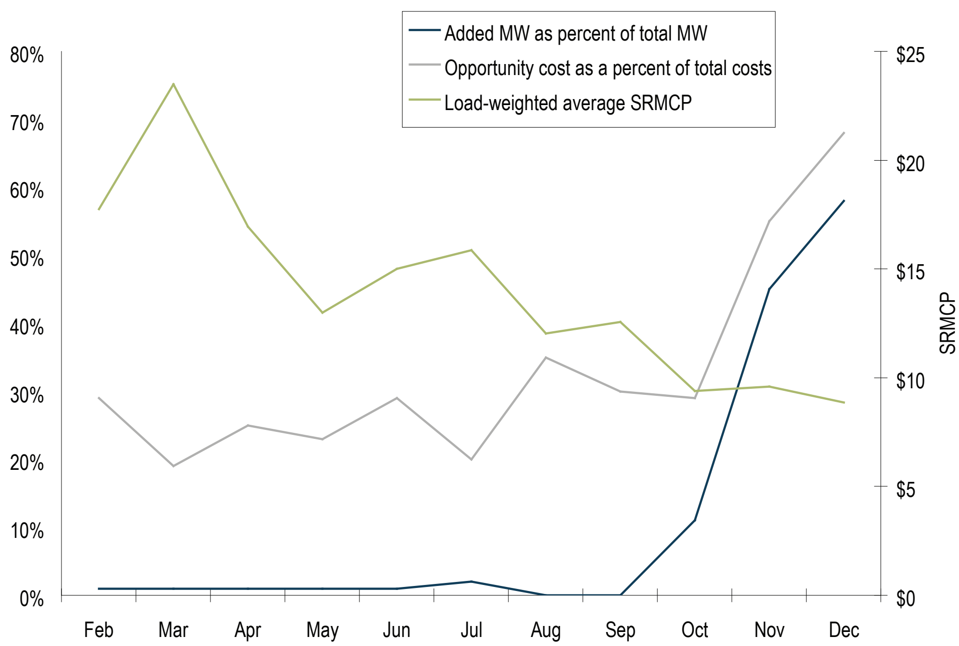
There was a significant change in the operation of the Synchronized Reserve Market in the last quarter of 2007 as PJM relied less on the market and more on out-of-market purchases of spinning reserve for local needs. Beginning in October and increasing substantially in November and December, there was an increase in the amount of CT-based, synchronized condenser MW added by PJM market operations to the Synchronized Reserve Market after market clearing. (See Figure 6-10 for added MW as a percent of total MW.) MW added after the market cleared accounted for more than 50 percent of total synchronized reserve MW purchased in December. Such synchronized reserve MW are not part of the market-clearing process so they do not affect the price of synchronized reserve, but they do increase the amount of synchronized reserve purchased for which load-serving entities (LSEs) must pay. (See Figure 6-10 for load-weighted, average SRMCP.)

There was an increase in spinning reserve MW purchased by PJM for local needs in New Jersey, including those related to the operation of the Neptune transmission line to Long Island, beginning in midsummer 2007. These spinning reserve services were initially accounted for as operating reserve. Effective in October, PJM determined that these spinning reserve services should be included in the Synchronized Reserve Market rather than as operating reserve.

The increase in out-of-market purchases indicates that the Synchronized Reserve Market is not functioning to coordinate supply and demand. It is not clear why the additional synchronized reserve requirements cannot be procured via the market. If these requirements cannot be procured via the market, it is not clear why the out-of-market purchase of spinning reserve resources for local issues should not be treated as operating reserve charges. While the creation of the Synchronized Reserve Market for the entire RFC Zone suggested that there is a single, geographic market, the actual results are not consistent with that view.

This local dynamic contributes to the difference between the total costs to provide synchronized reserve and the market-clearing price.

Figure 6-10 Impact of synchronized condensing added to the combined Synchronized Reserve Market after market clearing: February through December 2007

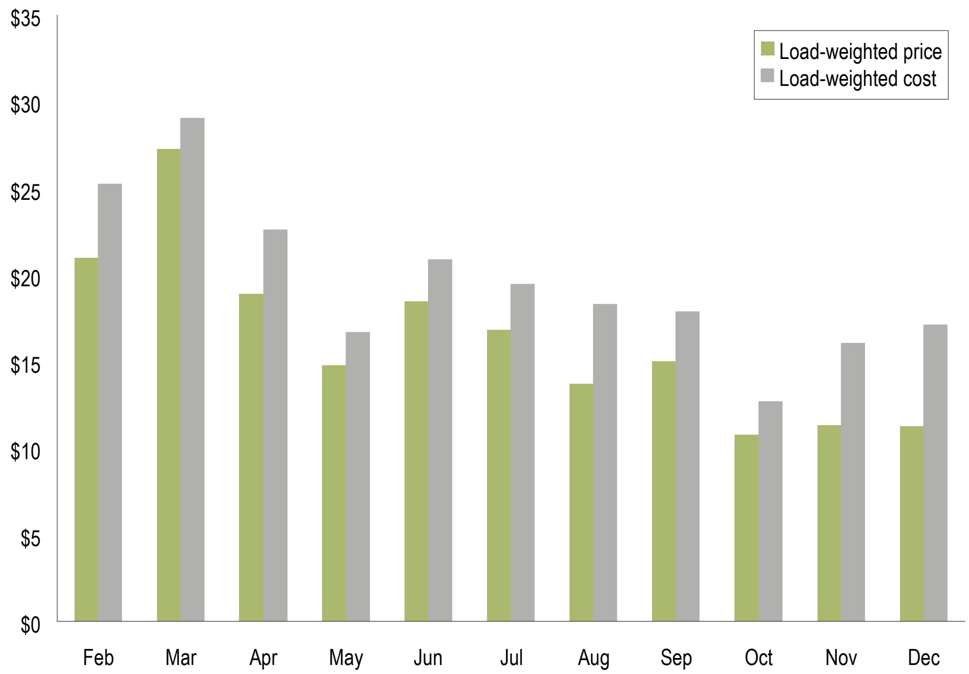


The addition of synchronized condensing MW to the Synchronized Reserve Market on an out-of-market basis means that the clearing price is below the efficient level for the defined market, or that the market is not correctly defined geographically and the price is below the efficient level for a more local market.

The difference between the Tier 2 Synchronized Reserve Market price and cost for Tier 2 synchronized reserve was less significant for the full year in 2007 than it had been in 2006. The difference in the Mid-Atlantic Subzone of the RFC Synchronized Reserve Market for 2007 between the monthly load-weighted, average price of Tier 2 synchronized reserve and cost of Tier 2 synchronized reserve was $5.04. The cost was 31 percent higher than the price. In 2006 the cost had been 49 percent higher than the price.

While there was a reduction in the annual difference between the cost and price of synchronized reserve, the difference began to increase at the end of 2007. The cost/price ratio was worse in the last three months of 2007 as a result of out-of-market purchases of synchronized reserve (See Figure 6-10).

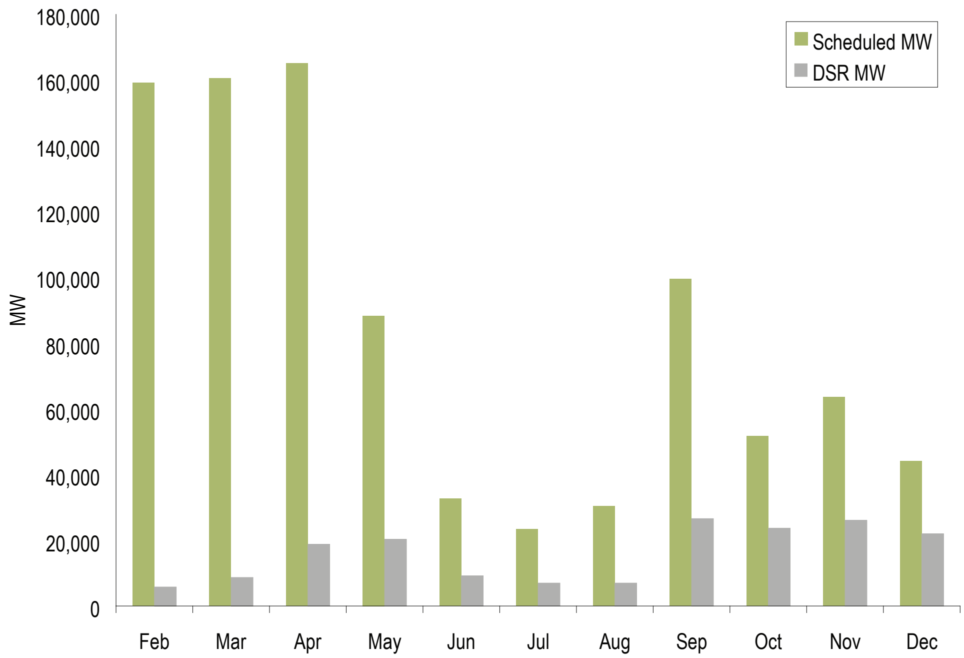
Figure 6-11 Comparison of RFC Tier 2 synchronized reserve price and cost (Dollars per MW): February through December 2007



DSR

Demand-side resources began participating in the Synchronized Reserve Markets in August 2006. Figure 6-12 shows total monthly synchronized reserve scheduled MW and cleared MW for DSR synchronized reserve. Participation of demand response grew significantly in 2007. Not only did more participants offer DSR, but demand response was generally less expensive than other forms of synchronized reserve. In 19 percent of hours during 2007 in which a Tier 2 Synchronized Reserve Market was cleared for the Mid-Atlantic Subzone, all synchronized reserve was provided by DSR.

Figure 6-12 PJM RFC Zone Tier 2 synchronized reserve scheduled MW: February through December 2007



Availability

A synchronized reserve deficit occurs when the combination of Tier 1 and Tier 2 synchronized reserve is not adequate to meet the synchronized reserve requirement. Neither PJM Synchronized Reserve Market experienced deficits during 2007.

SECTION 7 – 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.[1] 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 Auction Revenue Rights (ARRs) and/or Financial Transmission Rights (FTRs). While the transmission system and, therefore, ARRs/FTRs are not guaranteed to be a complete hedge against congestion, ARRs/FTRs do provide a substantial offset to the cost of congestion to firm load.[2]

The Market Monitoring Unit (MMU) analyzed congestion and its influence on PJM markets during 2007. In doing so, comparison to 2006 and certain other prior years was required.[3]

Overview

Congestion Cost

- Total Congestion. Total congestion costs increased by $241 million or 15 percent, from $1.603 billion in calendar year 2006 to $1.845 billion in calendar year 2007. Day-ahead congestion costs increased by $368 million or 22 percent, from $1.707 billion in calendar year 2006 to $2.075 billion in calendar year 2007. Balancing congestion costs decreased by $126 million or 122 percent, from -$104 million in calendar year 2006 to -$230 million in calendar year 2007. Total congestion costs have ranged from 6 percent to 9 percent of PJM annual total billings since 2003. Congestion costs were 6 percent of total PJM billings for 2007, compared to 8 percent in 2006. Total PJM billings for 2007 were $30.556 billion, a 46 percent increase from the $20.945 billion billed in 2006.

1 This is referred to as dispatching units out of economic merit order. Economic merit order is the order of all generator offers from lowest to highest cost. Congestion occurs when loadings on transmission facilities mean that the next unit in merit order cannot be used and that a higher cost unit must be used in its place.

2 See the *2007 State of the Market Report*, Volume II, Section 8, "Financial Transmission and Auction Revenue Rights," at "ARR and FTR Revenue and Congestion."

3 During calendar years 2004 and 2005, PJM conducted the phased integration of five control zones: ComEd, American Electric Power (AEP), The Dayton Power & Light Company (DAY), Duquesne Light Company (DLCO) and Dominion. By convention, control zones bear the name of a large utility service provider working within their boundaries. The nomenclature applies to the geographic area, not to any single company. For additional information on the integrations, their timing and their impact on the footprint of the PJM service territory, see the *2007 State of the Market Report*, Volume II, Appendix A, "PJM Geography."

- Monthly Congestion. Fluctuations in monthly congestion costs continued to be substantial. In 2007, 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.

Congestion Component of LMP and Facility or Zonal Congestion

- Congestion Component of Locational Marginal Price (LMP). To provide an indication of the geographic dispersion of congestion costs, the congestion component of LMP (CLMP) was calculated for control zones in PJM. Price separation between eastern and western control zones in PJM was primarily a result of congestion on the Bedington — Black Oak and 5004/5005 interfaces. 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.

- Congested Facilities. As was the case in 2006, congestion frequency was significantly higher in the Day-Ahead Market compared to the Real-Time Market in 2007.[4] Day-ahead congestion frequency increased in calendar year 2007 compared to 2006. In 2007, there were 62,216 day-ahead, congestion-event hours compared to 56,299 congestion-event hours in 2006. Day-ahead, congestion-event hours increased on Midwest Independent Transmission System Operator, Inc. (Midwest ISO) flowgates, interfaces and lines while congestion frequency on transformers decreased in 2007 compared to 2006. Real-time congestion frequency increased in calendar year 2007 compared to 2006. In 2007, there were 19,527 real-time, congestion-event hours compared to 19,510 congestion-event hours in 2006. Real-time, congestion-event hours increased on Midwest ISO flowgates, interfaces and transformers, while lines saw decreases. The Bedington — Black Oak Interface was the largest contributor to congestion costs in both 2006 and 2007. With $714 million in total congestion costs, it accounted for 39 percent of the total PJM congestion costs in 2007. The top four constraints in terms of congestion costs together contributed $1.159 billion, or 63 percent, of the total PJM congestion costs in 2007. The top four constraints also included the Cloverdale — Lexington line and the 5004/5005 and AP South interfaces.

- Zonal Congestion. In calendar year 2007, the AP Control Zone experienced the highest congestion cost of any control zone in PJM. The $448.6 million in congestion costs in the AP Control Zone represented a 32 percent increase from the $340.1 million in congestion costs the zone had experienced in 2006. The Bedington — Black Oak Interface and the Cloverdale — Lexington line constraints together contributed $286.9 million, or 64 percent of the total AP Control Zone congestion cost. The Dominion Control Zone had the second highest congestion cost in PJM in 2007. The $290.8 million in congestion costs in the Dominion Control Zone represented a 29 percent increase from the $224.7 million in congestion costs the zone had experienced in 2006. The Bedington — Black Oak Interface and Cloverdale — Lexington line constraints together contributed $185.5 million, or 64 percent of the total Dominion Control Zone congestion cost.

4 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 *2007 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.

Economic Planning Process

- Process Revision. PJM has made multiple filings related to economic metrics for evaluating transmission investments. The United States Federal Energy Regulatory Commission (FERC) has required that PJM use an approach with predefined formulas for determining whether a defined transmission investment passes the cost-benefit test including explicit accounting for changes in production costs, the costs of complying with environmental regulations, generation availability trends and demand-response trends. On October 9, 2007, PJM submitted its compliance filing to address these issues and to provide a formulaic approach for including transmission projects in the Regional Transmission Expansion Plan (RTEP). Under PJM's proposed approach, PJM would perform market simulations with and without the proposed transmission investments, including reliability-based investments and economic investments. The result would be used to determine the economic benefits of the investments and whether to include such investment in the RTEP. An economic investment would be included in the RTEP if the relative benefits and costs of the investment meet a benefit/cost ratio threshold of at least 1.25:1.

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 increased by $241 million or 15 percent, from $1.603 billion in calendar year 2006 to $1.845 billion in calendar year 2007. Day-ahead congestion costs increased by $368 million or 22 percent, from $1,707 billion in calendar year 2006 to $2.075 billion in calendar year 2007. Balancing congestion costs decreased by $126 million or 122 percent, from -$104 million in calendar year 2006 to -$230 million in calendar year 2007. 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 2007, there were 62,216 congestion-event hours compared to 56,299 congestion-event hours in 2006. In the Real-Time Energy Market in 2007, there were 19,527 congestion-event hours compared to 19,510 congestion-event hours in 2006.

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, is an essential input to a rational market and planning process.

ARRs and FTRs served as an effective hedge against congestion. In total, ARR and FTR revenues hedged 98.4 percent of congestion costs in the Day-Ahead Energy Market and in the balancing energy market within PJM for the 2006 to 2007 planning period and 92.3 percent of the congestion costs in PJM in the first seven months of the 2007 to 2008 planning period.[5] FTRs were paid at 100 percent of their target allocation for the planning year ended May 31, 2007, and at 100 percent of their target allocation for the first seven months of the current planning year.

5 See the *2007 State of the Market Report*, Volume II, Section 8, "Financial Transmission and Auction Revenue Rights," at Table 8-22, "ARR and FTR congestion hedging: Planning periods 2006 to 2007 and 2007 to 2008."

One constraint accounted for over a third of total congestion costs in 2007 and the top four constraints accounted for nearly two-thirds 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 2007 and 2006 and, with $714 million in total congestion costs, accounted for 39 percent of the total PJM congestion costs in 2007. The top four constraints in terms of congestion costs together accounted for 63 percent of the total PJM congestion costs in 2007.

Congestion

Congestion Accounting

Transmission congestion can exist in PJM's Day-Ahead and Real-Time Energy Market. Transmission congestion charges in the Day-Ahead Energy Market can be directly hedged by FTRs. Balancing market congestion charges can be hedged by FTRs to the extent that a participant's energy flows in real time are consistent with those in the Day-Ahead Energy Market.[6]

Total congestion charges are equal to the load congestion payments minus generation congestion credits, plus explicit congestion charges, incurred in both the Day-Ahead Energy Market and the balancing energy market.

- Day-Ahead Load Congestion Payments. Day-ahead load congestion payments are calculated for all cleared demand, decrement bids and Day-Ahead Energy Market sale transactions. (Decrement bids and energy sales can be thought of as scheduled load.) Day-ahead load congestion payments are calculated using MW and the load bus CLMP, the decrement bid CLMP or the CLMP at the source of the sale transaction, as applicable.

- Day-Ahead Generation Congestion Credits. Day-ahead generation congestion credits are calculated for all cleared generation and increment offers and Day-Ahead Energy Market purchase transactions. (Increment offers and energy purchases can be thought of as scheduled generation.) Day-ahead generation congestion credits are calculated using MW and the generator bus CLMP, the increment offer's CLMP or the CLMP at the sink of the purchase transaction, as applicable.

- Balancing Load Congestion Payments. Balancing load congestion payments are calculated for all deviations between a PJM member's real-time load and energy sale transactions and their day-ahead cleared demand, decrement bids and energy sale transactions. Balancing load congestion payments are calculated using MW deviations and the real-time CLMP for each bus where a deviation exists.

- Balancing Generation Congestion Credits. Balancing generation congestion credits are calculated for all deviations between a PJM member's real-time generation and energy purchase transactions and the day-ahead cleared generation, increment offers and energy purchase transactions. Balancing generation congestion credits are calculated using MW deviations and the real-time CLMP for each bus where a deviation exists.

6 The terms *congestion charges* and *congestion costs* are both used to refer to the costs associated with congestion. The term, congestion charges, is used in documents by PJM's Market Settlement Operations.

- Explicit Congestion Charges. Explicit congestion charges are the net congestion charges associated with point-to-point energy transactions. These charges equal the product of the transacted MW and CLMP differences between sources (origins) and sinks (destinations) in the Day-Ahead Energy Market. Balancing energy market explicit congestion charges equal the product of the differences between the real-time and day-ahead transacted MW and the differences between the real-time CLMP at the transactions' sources and sinks.

The congestion charges associated with specific constraints are the sum of the total day-ahead and balancing congestion costs associated with those constraints. The congestion charges in each zone are the sum of the congestion charges associated with each constraint that affects prices in the zone. The network nature of the transmission system means that congestion costs in a zone are frequently the result of constrained facilities located outside that zone.

Congestion costs can be both positive and negative. Congestion is defined with respect to the system marginal price (SMP), which is the single system price that would occur in the absence of any congestion, excluding losses. When a transmission constraint occurs, congestion is positive on one side of the constraint and negative on the other side of the constraint and the corresponding congestion component of LMP (CLMP) is positive or negative. The CLMP measures the difference between the actual LMP that results from transmission constraints, excluding losses, and the unconstrained SMP. If an area experiences lower prices because of a constraint, the CLMP in that area is negative.

Total Calendar Year Congestion

Congestion charges are comprised of hourly congestion revenue and net negative congestion. Congestion charges have ranged from 6 percent to 9 percent of annual total PJM billings since 2003.[7] Table 7-1 shows total congestion by year from 2003 through 2007. Total congestion charges were $1.845 billion in calendar year 2007, a 15 percent increase from $1.603 billion in calendar year 2006.

Table 7-1 Total annual PJM congestion (Dollars (Millions)): Calendar years 2003 to 2007

	Congestion Charges	Percent Change	Total PJM Billing	Percent of PJM Billing
2003	$464	NA	$6,900	7%
2004	$750	62%	$8,700	9%
2005	$2,092	179%	$22,630	9%
2006	$1,603	(23%)	$20,945	8%
2007	$1,845	15%	$30,556	6%
Total	$6,754		$89,731	8%

Total congestion charges appearing in Table 7-1 include both congestion charges associated with PJM facilities and those associated with reciprocal, coordinated flowgates in the Midwest ISO whose operating limits are respected by PJM.[8]

7 Calculated values shown in Section 7, "Congestion," are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

8 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. And PJM Interconnection, L.L.C." (February 5, 2008) (Accessed February 5, 2008), Section 6.1 < http://www.pjm.com/documents/downloads/agreements/joa-complete.pdf> (1,034 KB).

Monthly Congestion

Table 7-2 shows that during calendar year 2007, monthly congestion charges ranged from a maximum of $226 million in December 2007 to a minimum of $90 million in May 2007. Approximately 23 percent of all calendar year 2007 congestion occurred in the months of August and December.

Table 7-2 Monthly PJM congestion charges (Dollars (Millions)): Calendar years 2006 to 2007

	Total Congestion Charges	
	2006	2007
Jan	$155	$112
Feb	$159	$175
Mar	$94	$159
Apr	$49	$109
May	$68	$90
Jun	$159	$188
Jul	$295	$205
Aug	$376	$207
Sept	$69	$136
Oct	$41	$122
Nov	$46	$117
Dec	$91	$226

Congestion Component of LMP

The congestion component of LMP was calculated for each PJM control zone, to provide an indication of the geographic dispersion of congestion costs. The congestion component of LMP for control zones is presented in Table 7-3 for calendar years 2006 and 2007.

Table 7-3 shows overall congestion patterns in 2007. Price separation between eastern and western control zones in PJM was primarily a result of congestion on the Bedington — Black Oak and 5004/5005 interfaces. These constraints generally had a positive congestion component of LMP in eastern control zones located on the constrained side of the affected facilities while the unconstrained western zones had a negative congestion component of LMP.

Table 7-3 Annual average congestion component of LMP: Calendar years 2006 to 2007

	2006		2007	
Control Zone	Day Ahead	Real Time	Day Ahead	Real Time
AECO	$8.13	$8.34	$6.27	$6.42
AEP	($5.06)	($4.95)	($7.59)	($8.80)
AP	$0.88	$1.52	$0.77	$1.33
BGE	$9.06	$10.21	$9.50	$12.08
ComEd	($5.41)	($5.67)	($7.80)	($9.42)
DAY	($6.12)	($5.98)	($8.12)	($9.54)
DLCO	($7.49)	($7.85)	($9.22)	($11.13)
DPL	$6.54	$5.90	$5.72	$6.09
Dominion	$8.13	$9.25	$8.42	$9.89
JCPL	$4.78	$4.61	$6.49	$7.36
Met-Ed	$6.19	$5.47	$6.24	$7.32
PECO	$6.01	$5.21	$5.01	$4.82
PENELEC	($0.37)	($0.55)	($1.14)	($1.46)
PPL	$5.03	$4.33	$4.75	$4.89
PSEG	$7.23	$7.38	$7.05	$7.43
Pepco	$10.33	$11.66	$10.83	$13.00
RECO	$7.18	$6.69	$6.77	$6.50

Congested Facilities

A congestion event exists when a unit or units must be dispatched out-of-merit order to control the impact of a contingency on a monitored facility or to control an actual overload. A congestion-event hour exists when a specific facility is constrained for one or more five-minute intervals within an hour. A congestion-event hour differs from a constraint hour, which is any hour during which one or more facilities are congested. Thus, if two facilities are constrained during an hour, the result is two congestion-event hours and one constraint hour. Constraints are often simultaneous, so the number of congestion-event hours exceeds the number of constraint hours and the number of congestion-event hours can exceed the number of hours in a year. 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. This is also consistent with the way in which PJM reports real-time congestion. In 2007, there were 62,216 day-ahead, congestion-event hours, an increase of 10.5 percent from the 56,299 in 2006. In 2007, there were 19,527 real-time, congestion-event hours, a 0.09 percent increase from the 19,510 in 2006.

Congestion by Facility Type and Voltage

Both day-ahead and real-time, congestion-event hours increased on the Midwest ISO flowgates and interfaces in 2007. Day-ahead, congestion-event hours increased on lines while real-time, congestion-event hours decreased on lines. Day-ahead, congestion-event hours decreased on transformers and real-time, congestion-event hours increased on transformers.

Day-ahead congestion costs increased on all facility types in 2007 except unclassified.[9] Balancing congestion costs decreased on all facility types in 2007.

Table 7-4 provides congestion-event-hour subtotals and congestion cost subtotals comparing 2007 calendar year results by facility type: line, transformer, interface, flowgate and unclassified facilities.[10] For comparison, this information is presented in Table 7-5 for calendar year 2006.

Total congestion costs associated with Midwest ISO flowgates was unchanged from 2006 at -$6 million. The Crete — St. Johns Tap and Tower Road flowgates together accounted for $0.5 million in congestion costs and were the largest contributors to positive congestion costs among Midwest ISO flowgates in 2007. The largest contribution to negative congestion costs among Midwest ISO flowgates came from the State Line — Wolf Lake flowgate with -$2.2 million in 2007 congestion costs.

Total congestion costs associated with interfaces increased 30 percent from $764 million in 2006 to $991.1 million in 2007. Interfaces typically include multiple transmission facilities and reflect power flows into or through a wider geographic area. Interface congestion constituted 54 percent of total PJM congestion costs in 2007. Among interfaces, the Bedington — Black Oak and 5004/5005 interfaces accounted for the largest contribution to positive congestion costs in 2007. Bedington — Black Oak, with $714 million in congestion, had the highest congestion cost of any facility in PJM, accounting for 39 percent of the total PJM congestion costs in 2007. The Bedington — Black Oak and 5004/5005 interfaces together accounted for $830.5 million or 45 percent of total PJM congestion costs in 2007. The largest contribution to negative congestion costs among interface constraints was the PL North Interface with -$2.4 million in 2007.

Total congestion costs associated with lines increased 5 percent from $495.8 million in 2006 to $521.6 million in 2007. Line congestion accounted for 28 percent of the total PJM congestion costs for 2007. The Cloverdale — Lexington, Branchburg — Readington and Atlantic — Larrabee lines together accounted for $313.3 million or 60 percent of all line congestion costs and were the largest contributors to positive congestion among lines in 2007. The largest contribution to negative congestion among lines came from the Darwin — Eugene line with -$12.6 million in 2007.

Total congestion costs associated with transformers decreased 3 percent from $334.6 million in 2006 to $325.4 million in 2007. Congestion on transformers accounted for 18 percent of the total PJM congestion costs in 2007. The Kammer and Bedington transformers together accounted for $124 million or 38 percent of all transformer congestion costs and were the largest contributors to positive congestion costs among transformers in 2007. The largest contribution to negative congestion among transformers came from the Dumont transformer in the AEP Control Zone with -$0.9 million in 2007.

9 Unclassified constraints appear in the Day-Ahead Market only and represent congestion costs incurred on market elements which are not posted by PJM. Congestion frequency associated with these unclassified constraints is not presented in order to be consistent with the posting of constrained facilities by PJM.

10 The term *flowgate* refers to Midwest ISO flowgates in this context.

Table 7-4 Congestion summary (By facility type): Calendar year 2007

	Congestion Costs (Millions)										
	Day Ahead				Balancing					Event Hours	
Type	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Flowgate	($10.4)	($14.9)	$4.4	$9.0	($19.6)	($19.0)	($14.4)	($15.0)	($6.0)	1,489	1,069
Interface	$440.8	($528.1)	$58.8	$1,027.7	$466.7	$483.9	($19.3)	($36.6)	$991.1	9,798	2,856
Line	($295.8)	($901.3)	$67.6	$673.1	$71.4	$121.5	($101.4)	($151.5)	$521.6	39,071	10,916
Transformer	$128.0	($192.3)	$32.1	$352.4	($34.5)	($31.9)	($24.3)	($27.0)	$325.4	11,858	4,686
Unclassified	$12.2	$1.1	$1.3	$12.4	$0.0	$0.0	$0.0	$0.0	$12.4	NA	NA
Total	$274.9	($1,635.5)	$164.2	$2,074.6	$484.0	$554.6	($159.5)	($230.1)	$1,844.5	62,216	19,527

Table 7-5 Congestion summary (By facility type): Calendar year 2006

	Congestion Costs (Millions)										
	Day Ahead				Balancing					Event Hours	
Type	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Flowgate	($15.2)	($18.4)	$2.0	$5.2	($19.3)	($18.2)	($10.0)	($11.2)	($6.0)	1,350	859
Interface	$1,459.1	$726.8	$20.1	$752.4	$1,302.3	$1,284.5	($6.2)	$11.6	$764.0	8,273	2,792
Line	($94.3)	($645.5)	$34.3	$585.5	$235.5	$286.4	($38.7)	($89.6)	$495.8	34,558	11,447
Transformer	$391.9	$59.1	$16.4	$349.2	$471.8	$468.7	($17.6)	($14.6)	$334.6	12,118	4,412
Unclassified	$25.8	$13.8	$3.0	$14.9	$0.0	$0.0	$0.0	$0.0	$14.9	NA	NA
Total	$1,767.2	$135.9	$75.8	$1,707.1	$1,990.3	$2,021.5	($72.6)	($103.8)	$1,603.4	56,299	19,510

Table 7-6 shows congestion costs by facility voltage class. In comparison to 2006 (shown in Table 7-7), congestion costs decreased across 765 kV, 345 kV, 69 kV and unclassified class facilities in 2007. Congestion costs increased across 500 kV, 230 kV, 138 kV, 115 kV and 12 kV class facilities in 2007.

Congestion costs associated with 765 kV facilities decreased 58 percent from $16.7 million in 2006 to the $7.0 million experienced in 2007. Congestion on 765 kV facilities comprised less than 1 percent of total 2007 PJM congestion costs. The Axton — Jackson's Ferry line accounted for $5.9 million or 84 percent of all 765 kV congestion costs and was the largest contributor to positive congestion among 765 kV facilities in 2007. The Dumont — Wilton Center line was the largest contributor to negative congestion among 765 kV facilities with -$0.7 million in 2007.

Congestion costs associated with 500 kV facilities increased 26 percent from $1.023 billion in 2006 to $1.288 billion in 2007. Congestion on 500 kV facilities comprised 70 percent of total 2007 PJM congestion costs. The Bedington — Black Oak Interface and the Cloverdale — Lexington line together accounted for $941.1 million or 73 percent of all 500 kV congestion costs; they were the largest contributors to positive congestion among 500 kV facilities in 2007. The Bristers — Ox line was the largest contributor to negative congestion among 500 kV facilities with -$1.1 million in 2007.

Congestion costs associated with 230 kV facilities increased 35 percent from $166.7 million in 2006 to $225.8 million in 2007. Congestion on 230 kV facilities comprised 12 percent of total 2007 PJM congestion costs. The Branchburg — Readington line accounted for $63.1 million or 28 percent of all 230 kV congestion costs and was the largest contributor to positive congestion among 230 kV facilities in 2007. The largest contribution to negative congestion among 230 kV facilities came from the PL North Interface with -$2.4 million in 2007.

Congestion costs associated with 138 kV facilities increased 20 percent from $181.7 million in 2006 to $218.9 million in 2007. Congestion on 138 kV facilities comprised 12 percent of total 2007 PJM congestion costs. The Bedington and Meadow Brook transformers together accounted for $104.6 million or 48 percent of all 138 kV congestion costs and were the largest contributors to positive congestion among 138 kV facilities in 2007. The largest contribution to negative congestion among 138 kV facilities came from the State Line — Wolf Lake line with -$2.2 million in 2007.

Table 7-6 Congestion summary (By facility voltage): Calendar year 2007

	Congestion Costs (Millions)										
	Day Ahead				Balancing					Event Hours	
Voltage (kV)	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
765	($3.4)	($10.0)	$1.3	$7.8	($0.3)	($0.1)	($0.6)	($0.8)	$7.0	422	17
500	$609.5	($617.7)	$93.7	$1,320.9	$671.5	$653.9	($50.2)	($32.6)	$1,288.3	15,691	5,938
345	$76.2	$2.1	$18.1	$92.2	$94.9	$113.9	($50.6)	($69.6)	$22.6	3,719	1,973
230	($496.6)	($759.7)	$18.0	$281.1	($259.1)	($226.2)	($22.4)	($55.3)	$225.8	11,927	3,141
138	$26.5	($212.4)	$30.0	$268.9	($7.8)	$4.2	($37.9)	($50.0)	$218.9	16,569	5,313
115	$39.7	($19.8)	$1.5	$61.1	($20.3)	($1.9)	$2.4	($16.0)	$45.1	6,337	1,916
69	$11.0	($19.0)	$0.2	$30.2	$5.1	$10.8	($0.2)	($5.9)	$24.3	7,434	1,229
12	($0.1)	($0.1)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	117	0
Unclassified	$12.2	$1.1	$1.3	$12.4	$0.0	$0.0	$0.0	$0.0	$12.4	NA	NA
Total	$274.9	($1,635.5)	$164.2	$2,074.6	$484.0	$554.6	($159.5)	($230.1)	$1,844.5	62,216	19,527

Table 7-7 Congestion summary (By facility voltage): Calendar year 2006

	Congestion Costs (Millions)										
	Day Ahead				Balancing					Event Hours	
Voltage (kV)	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
765	$35.1	$20.2	$2.0	$16.9	$10.2	$10.7	$0.3	($0.2)	$16.7	574	41
500	$2,061.9	$1,087.1	$32.7	$1,007.5	$1,850.8	$1,819.3	($16.3)	$15.2	$1,022.7	13,170	5,028
345	$336.5	$171.9	$13.3	$177.9	$121.6	$147.3	($19.0)	($44.7)	$133.2	5,949	2,481
230	($864.1)	($1,043.3)	$14.1	$193.3	($251.5)	($240.5)	($15.5)	($26.6)	$166.7	10,249	3,367
138	$59.7	($142.8)	$9.4	$211.8	$151.3	$161.6	($19.8)	($30.1)	$181.7	15,713	5,102
115	$59.7	$12.5	$0.8	$48.0	$47.9	$58.4	($1.4)	($11.9)	$36.1	4,486	1,344
69	$52.7	$16.4	$0.5	$36.8	$60.0	$64.6	($0.9)	($5.4)	$31.4	6,129	2,147
12	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	29	0
Unclassified	$25.8	$13.8	$3.0	$14.9	$0.0	$0.0	$0.0	$0.0	$14.9	NA	NA
Total	$1,767.2	$135.9	$75.8	$1,707.1	$1,990.3	$2,021.5	($72.6)	($103.8)	$1,603.4	56,299	19,510

Constraint Duration

Table 7-8 lists calendar year 2006 and 2007 constraints that were most frequently in effect and shows changes in congestion-event hours from 2006 to 2007.[11]

Constraints 1, 5, 7, 12, 20 and 23 are among the primary operating interfaces. For this group, the number of Day-Ahead Energy Market, congestion-event hours increased from 10,523 to 11,383 hours between 2006 and 2007. The number of Real-Time Energy Market, congestion-event hours for the primary interfaces decreased from 4,164 to 3,964 hours between 2006 and 2007. The AP Control Zone facilities, items number 1, 5, 7 and 20, were constrained 9,690 hours in the Day-Ahead Market in 2007, compared to 8,843 hours in 2006. In the Real-Time Market, these AP Control Zone facilities were constrained for 3,601 hours in 2007 and 3,821 hours in 2006. The PJM Mid-Atlantic Region facilities, items number 12 and 23, were constrained 1,693 hours in the Day-Ahead Market in 2007 compared to 1,680 hours in 2006. In the Real-Time Market, these PJM Mid-Atlantic facilities were constrained 363 hours in 2007 and 343 hours in 2006.

11 Presented in order of descending sum of 2007 day-ahead and real-time, congestion-event hours.

Table 7-8 Top 25 constraints with frequent occurrence: Calendar years 2006 to 2007

			Event Hours						Percent of Annual Hours					
			Day Ahead			Real Time			Day Ahead			Real Time		
No.	Constraint	Type	2006	2007	Change	2006	2007	Change	2006	2007	Change	2006	2007	Change
1	Bedington - Black Oak	Interface	3,875	5,493	1,618	1,812	1,836	24	44%	63%	18%	21%	21%	0%
2	Cloverdale - Lexington	Line	1,517	3,704	2,187	961	1,885	924	17%	42%	25%	11%	22%	11%
3	Pinehill - Stratford	Line	0	3,274	3,274	0	0	0	0%	37%	37%	0%	0%	0%
4	Branchburg - Readington	Line	704	2,324	1,620	480	721	241	8%	27%	18%	5%	8%	3%
5	Kammer	Transformer	2,043	2,005	(38)	688	947	259	23%	23%	(0%)	8%	11%	3%
6	Elrama - Mitchell	Line	654	1,883	1,229	258	784	526	7%	21%	14%	3%	9%	6%
7	Wylie Ridge	Transformer	2,286	1,486	(800)	1,084	685	(399)	26%	17%	(9%)	12%	8%	(5%)
8	5004/5005 Interface	Interface	1,738	1,512	(226)	341	386	45	20%	17%	(3%)	4%	4%	1%
9	State Line - Wolf Lake	Flowgate	943	1,241	298	423	590	167	11%	14%	3%	5%	7%	2%
10	Cedar Grove - Roseland	Line	3,692	1,677	(2,015)	541	133	(408)	42%	19%	(23%)	6%	2%	(5%)
11	East Towanda	Transformer	144	1,055	911	2	410	408	2%	12%	10%	0%	5%	5%
12	Central	Interface	699	1,334	635	15	25	10	8%	15%	7%	0%	0%	0%
13	Bedington	Transformer	662	928	266	451	429	(22)	8%	11%	3%	5%	5%	(0%)
14	Gardners - Hunterstown	Line	496	953	457	257	271	14	6%	11%	5%	3%	3%	0%
15	Beckett - Paulsboro	Line	169	768	599	50	417	367	2%	9%	7%	1%	5%	4%
16	Meadow Brook	Transformer	726	868	142	124	233	109	8%	10%	2%	1%	3%	1%
17	Bedington - Nipetown	Line	185	841	656	8	175	167	2%	10%	7%	0%	2%	2%
18	Mahans Lane - Tidd	Line	382	727	345	118	210	92	4%	8%	4%	1%	2%	1%
19	Calumet - River E.C.	Line	913	842	(71)	0	0	0	10%	10%	(1%)	0%	0%	0%
20	AP South	Interface	639	706	67	237	133	(104)	7%	8%	1%	3%	2%	(1%)
21	Atlantic - Larrabee	Line	0	680	680	0	134	134	0%	8%	8%	0%	2%	2%
22	Brunswick - Edison	Line	464	667	203	206	125	(81)	5%	8%	2%	2%	1%	(1%)
23	West	Interface	981	359	(622)	328	338	10	11%	4%	(7%)	4%	4%	0%
24	Branchburg - Flagtown	Line	188	580	392	123	104	(19)	2%	7%	4%	1%	1%	(0%)
25	Mitchell - Shepler Hill	Line	677	523	(154)	307	160	(147)	8%	6%	(2%)	4%	2%	(2%)

Constraint Costs

Table 7-9 and Table 7-10 present the top constraints affecting congestion costs by facility for calendar years 2006 and 2007.[12] The Bedington — Black Oak Interface was the largest contributor to congestion costs in both 2007 and 2006. With $714 million in total congestion costs, it accounted for 39 percent of the total PJM congestion costs in 2007. The top four constraints in terms of congestion costs together comprised 63 percent of the total PJM congestion costs in 2007.

12 Presented in descending order of annual total congestion costs.

Table 7-9 Top 25 constraints affecting annual PJM congestion costs (By facility): Calendar year 2007

				Congestion Costs (Millions)									Percent of Total PJM Congestion Costs
				Day Ahead				Balancing					
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	2007
1	Bedington - Black Oak	Interface	500	$466.3	($227.9)	$43.4	$737.6	$523.6	$531.0	($16.2)	($23.5)	$714.0	39%
2	Cloverdale - Lexington	Line	AEP	$132.0	($69.2)	$22.4	$223.6	$203.5	$177.5	($22.5)	$3.5	$227.1	12%
3	5004/5005 Interface	Interface	500	$3.4	($111.9)	$5.7	$121.0	($33.9)	($29.6)	($0.3)	($4.6)	$116.5	6%
4	AP South	Interface	500	$36.9	($57.1)	$4.3	$98.4	$12.5	$10.4	$1.0	$3.1	$101.5	6%
5	Kammer	Transformer	500	$31.3	($16.3)	$11.6	$59.2	($39.8)	($48.6)	($3.7)	$5.1	$64.3	3%
6	Branchburg - Readington	Line	PSEG	($505.9)	($597.3)	$9.4	$100.8	($358.0)	($328.7)	($8.4)	($37.6)	$63.1	3%
7	Bedington	Transformer	AP	($16.9)	($77.1)	$2.9	$63.1	($2.9)	($1.4)	($2.0)	($3.4)	$59.7	3%
8	Meadow Brook	Transformer	AP	($3.4)	($47.5)	$0.7	$44.9	$3.2	$2.8	($0.4)	$0.0	$44.9	2%
9	Central	Interface	500	($43.7)	($73.5)	$2.5	$32.4	($2.0)	($2.1)	$0.0	$0.0	$32.4	2%
10	Atlantic - Larrabee	Line	JCPL	$15.2	($13.5)	$1.7	$30.3	$1.2	$7.6	($0.8)	($7.2)	$23.1	1%
11	Branchburg - Flagtown	Line	PSEG	($0.3)	($21.4)	$0.4	$21.5	$4.2	$4.8	($1.3)	($2.0)	$19.5	1%
12	Wylie Ridge	Transformer	AP	$27.4	$6.2	$10.1	$31.3	($30.7)	($27.9)	($9.6)	($12.4)	$18.9	1%
13	Brunner Island - Yorkana	Line	Met-Ed	($0.4)	($15.1)	$0.1	$14.9	$50.3	$46.7	$0.1	$3.7	$18.6	1%
14	East	Interface	500	($25.2)	($41.9)	$0.8	$17.5	($0.4)	($0.4)	($0.0)	($0.0)	$17.4	1%
15	Amos	Transformer	AEP	$1.9	($16.5)	$0.5	$18.9	$14.6	$13.2	($3.4)	($2.0)	$17.0	1%
16	Conastone	Transformer	BGE	($2.9)	($16.3)	$0.4	$13.8	$15.0	$13.7	($0.3)	$1.0	$14.8	1%
17	Kanawha - Matt Funk	Line	AEP	($10.6)	($24.3)	$1.8	$15.5	$3.9	$4.4	($0.3)	($0.8)	$14.7	1%
18	Doubs	Transformer	AP	$5.8	($9.0)	$0.5	$15.3	($0.9)	($1.1)	($0.7)	($0.5)	$14.7	1%
19	Beckett - Paulsboro	Line	AECO	$1.6	($14.6)	$0.1	$16.3	$4.5	$6.5	($0.0)	($2.1)	$14.2	1%
20	Bedington - Nipetown	Line	AP	$12.5	($1.9)	$0.6	$15.0	$10.6	$10.9	($0.8)	($1.1)	$13.9	1%
21	Cloverdale	Transformer	AEP	$0.1	($13.0)	$1.5	$14.5	$2.6	$2.9	($0.7)	($1.0)	$13.5	1%
22	Darwin - Eugene	Line	AEP	($0.2)	($3.5)	$0.1	$3.3	$0.1	$6.1	($9.9)	($16.0)	($12.6)	(1%)
23	Unclassified	Unclassified	Unclassified	$12.2	$1.1	$1.3	$12.4	$0.0	$0.0	$0.0	$0.0	$12.4	1%
24	West	Interface	500	$4.1	($13.3)	$2.0	$19.4	($27.0)	($22.3)	($3.6)	($8.4)	$11.0	1%
25	Axton	Transformer	AEP	($4.8)	($14.1)	$1.1	$10.5	$0.0	$0.0	$0.0	$0.0	$10.5	1%

Table 7-10 Top 25 constraints affecting annual PJM congestion costs (By facility): Calendar year 2006

				Congestion Costs (Millions)									Percent of Total PJM Congestion Costs
				Day Ahead				Balancing					
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	2006
1	Bedington - Black Oak	Interface	500	$1,442.4	$971.9	$15.6	$486.1	$1,113.7	$1,104.9	($3.3)	$5.5	$491.6	31%
2	5004/5005 Interface	Interface	500	($10.7)	($115.5)	$0.6	$105.4	$11.4	$10.4	($0.4)	$0.6	$106.0	7%
3	Mount Storm - Pruntytown	Line	AP	$345.2	$249.4	$4.5	$100.3	$227.2	$228.2	($0.9)	($1.9)	$98.4	6%
4	Kanawha - Matt Funk	Line	AEP	$207.3	$108.2	$2.7	$101.9	$168.7	$181.1	($5.1)	($17.5)	$84.4	5%
5	AP South	Interface	500	$129.8	$55.5	$1.9	$76.2	$184.2	$178.0	($1.6)	$4.6	$80.8	5%
6	Cloverdale - Lexington	Line	AEP	$95.4	$34.0	$3.4	$64.8	$229.1	$224.0	($7.0)	($1.9)	$63.0	4%
7	West	Interface	500	($0.1)	($54.3)	$1.2	$55.5	($3.8)	($5.6)	($0.9)	$0.9	$56.4	4%
8	Meadow Brook	Transformer	AP	($19.3)	($75.1)	($0.9)	$54.9	$4.2	$4.0	$0.2	$0.4	$55.2	3%
9	Kammer	Transformer	500	$79.1	$41.4	$3.9	$41.7	$40.1	$33.5	($0.8)	$5.7	$47.4	3%
10	Bedington	Transformer	AP	$32.6	($12.2)	$0.9	$45.7	$88.8	$90.6	($0.9)	($2.7)	$42.9	3%
11	Doubs - Mount Storm	Line	500	$66.1	$28.6	$0.5	$38.0	$31.3	$30.0	($0.8)	$0.5	$38.5	2%
12	Doubs	Transformer	AP	($2.8)	($35.4)	($0.1)	$32.5	$20.5	$20.0	($0.1)	$0.3	$32.8	2%
13	Axton	Transformer	AEP	$63.7	$41.7	$1.8	$23.8	$9.2	$9.7	($0.1)	($0.7)	$23.1	1%
14	Whitpain	Transformer	PECO	$8.0	($12.9)	$0.6	$21.5	($9.7)	($8.1)	($0.8)	($2.4)	$19.1	1%
15	Aqueduct - Doubs	Line	AP	$77.8	$60.1	$0.6	$18.4	$50.1	$49.4	($0.6)	$0.1	$18.5	1%
16	Laurel - Woodstown	Line	AECO	$32.4	$11.8	$0.2	$20.8	$39.2	$42.4	($0.5)	($3.7)	$17.2	1%
17	Cedar Grove - Roseland	Line	PSEG	($750.7)	($770.5)	$1.8	$21.6	($184.5)	($178.8)	$0.3	($5.4)	$16.2	1%
18	Central	Interface	500	($72.1)	($87.4)	$0.6	$15.8	($1.7)	($1.6)	($0.0)	($0.1)	$15.7	1%
19	Unclassified	Unclassified	Unclassified	$25.8	$13.8	$3.0	$14.9	$0.0	$0.0	$0.0	$0.0	$14.9	1%
20	East	Interface	500	($29.6)	($42.3)	$0.2	$12.9	($1.1)	($1.3)	$0.0	$0.2	$13.1	1%
21	Wylie Ridge	Transformer	AP	$46.0	$25.3	$6.8	$27.4	$18.0	$25.6	($6.7)	($14.3)	$13.1	1%
22	Axton - Jacksons Ferry	Line	AEP	$29.2	$17.7	$1.2	$12.7	$1.7	$1.8	($0.0)	($0.2)	$12.5	1%
23	Dooms	Transformer	Dominion	$23.0	$11.2	$0.7	$12.4	$58.4	$56.7	($2.3)	($0.6)	$11.8	1%
24	Cloverdale	Transformer	AEP	$19.5	$8.2	$0.5	$11.8	$10.4	$10.5	($0.3)	($0.3)	$11.5	1%
25	Hunterstown	Transformer	Met-Ed	$30.9	$21.0	($0.1)	$9.8	$1.4	$1.6	$0.0	($0.2)	$9.5	1%

Congestion-Event Summary for Midwest ISO Flowgates

PJM and the Midwest ISO have a joint operating agreement (JOA) which defines a coordinated methodology for congestion management. This agreement establishes reciprocal, coordinated flowgates in the combined footprint whose operating limits are respected by the operators of both organizations.[13] A flowgate is a representative modeling of facilities or groups of facilities that may act as potential constraint points on the regional system.[14] PJM models these coordinated flowgates and controls for them in its security-constrained, economic dispatch. Table 7-11 and Table 7-12 show the Midwest ISO flowgates which PJM took dispatch action to control during 2007 and 2006, respectively, and which had the greatest congestion cost impact on PJM. Total congestion costs are the sum of the day-ahead and balancing congestion cost components. Total congestion costs associated with a given constraint may be positive or negative in value. The top congestion cost impacts for Midwest ISO flowgates affecting PJM dispatch are presented by constraint, in descending order of the absolute value of total congestion costs. Among Midwest ISO flowgates in 2007, the Crete — St. Johns Tap constraint made the most significant contribution to positive congestion while the State Line — Wolf Lake line made the most significant contribution to negative congestion. Among Midwest ISO flowgates in 2006, the Pierce and Rising flowgates made the most significant contributions to positive congestion, while the State Line — Wolf Lake flowgate made the most significant negative contribution.

Table 7-11 Top congestion cost impacts from Midwest ISO flowgates affecting PJM dispatch (By facility): Calendar year 2007

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
State Line - Wolf Lake	Flowgate	Midwest ISO	($9.6)	($13.1)	$3.9	$7.3	($12.9)	($12.2)	($8.7)	($9.5)	($2.2)	1,241	590
Lanesville	Flowgate	Midwest ISO	$1.7	$1.0	($0.0)	$0.7	$0.3	$0.6	($2.1)	($2.4)	($1.7)	48	50
Pana North	Flowgate	Midwest ISO	$0.0	($0.0)	$0.0	$0.1	($0.4)	($0.4)	($1.8)	($1.8)	($1.7)	20	152
Salem	Flowgate	Midwest ISO	$0.0	$0.0	$0.0	$0.0	($0.2)	$0.1	($0.1)	($0.4)	($0.4)	0	19
Crete - St Johns Tap	Flowgate	Midwest ISO	($0.2)	($0.4)	$0.1	$0.3	($0.0)	($0.0)	($0.1)	($0.1)	$0.3	20	4
Tower Road	Flowgate	Midwest ISO	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.1)	$0.2	$0.2	$0.2	0	11
Dunes Acres - Michigan City	Flowgate	Midwest ISO	($2.3)	($2.4)	$0.4	$0.5	($4.3)	($5.3)	($1.7)	($0.7)	($0.2)	150	96
Coffeen - Pana North	Flowgate	Midwest ISO	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.1	$0.3	$0.2	$0.2	0	6
Seneca - Krendale	Flowgate	Midwest ISO	$0.0	$0.0	$0.0	$0.0	($1.5)	($1.4)	($0.1)	($0.2)	($0.2)	0	16
Queenston Flow West	Flowgate	Midwest ISO	$0.0	$0.0	$0.0	$0.0	($0.2)	($0.1)	($0.1)	($0.1)	($0.1)	0	16
NE Ohio	Flowgate	Midwest ISO	$0.0	$0.0	$0.0	$0.0	($0.3)	($0.0)	$0.1	($0.1)	($0.1)	0	8
Breed - West Casey	Flowgate	Midwest ISO	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.1)	($0.1)	($0.1)	0	2
Rising	Flowgate	Midwest ISO	$0.0	$0.0	$0.0	$0.0	($0.2)	($0.2)	($0.1)	($0.0)	($0.0)	0	6
Eau Claire - Arpin	Flowgate	Midwest ISO	$0.0	$0.0	$0.0	$0.0	$0.1	$0.1	($0.0)	($0.0)	($0.0)	0	35
Pierce	Flowgate	Midwest ISO	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.1)	($0.0)	$0.0	$0.0	0	43

13 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. And PJM Interconnection, L.L.C." (February 5, 2008) (Accessed February 5, 2008)< http://www.pjm.com/documents/downloads/agreements/joa-complete.pdf> (1,034 KB).

14 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. And PJM Interconnection, L.L.C." (February 5, 2008) (Accessed February 5, 2008), Section 2.2.18 < http://www.pjm.com/documents/downloads/agreements/joa-complete.pdf> (1,034 KB).

Table 7-12 Top congestion cost impacts from Midwest ISO flowgates affecting PJM dispatch (By facility): Calendar year 2006

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
State Line - Wolf Lake	Flowgate	Midwest ISO	($12.7)	($14.2)	$1.7	$3.2	($12.8)	($12.8)	($7.6)	($7.6)	($4.4)	943	423
Lanesville	Flowgate	Midwest ISO	$1.3	$0.8	$0.1	$0.6	($0.1)	$1.6	($0.7)	($2.4)	($1.8)	43	99
Pierce	Flowgate	Midwest ISO	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.2)	$0.3	$0.5	$0.5	0	21
New London - Webster	Flowgate	Midwest ISO	$0.0	$0.0	$0.0	$0.0	($2.5)	($2.4)	($0.3)	($0.4)	($0.4)	0	27
Rising	Flowgate	Midwest ISO	($1.6)	($1.9)	$0.0	$0.3	($0.2)	($0.3)	($0.1)	$0.0	$0.3	111	59
Dunes Acres - Michigan City	Flowgate	Midwest ISO	($1.3)	($1.4)	$0.1	$0.3	($2.6)	($3.2)	($1.2)	($0.6)	($0.3)	51	81
Breed - West Casey	Flowgate	Midwest ISO	$0.0	$0.0	$0.0	$0.0	$0.3	$0.3	($0.1)	($0.1)	($0.1)	0	9
Crete - St Johns Tap	Flowgate	Midwest ISO	($0.3)	($0.4)	$0.0	$0.1	($0.0)	($0.0)	($0.0)	$0.0	$0.1	7	5
Bain - Kenosha	Flowgate	Midwest ISO	$0.2	$0.1	$0.0	$0.1	($0.0)	$0.0	$0.0	($0.0)	$0.1	92	26
Pana North	Flowgate	Midwest ISO	($0.8)	($1.4)	($0.0)	$0.6	($0.3)	($0.0)	($0.3)	($0.5)	$0.1	103	79
State Line - Roxana	Flowgate	Midwest ISO	$0.0	$0.0	$0.0	$0.0	($0.3)	($0.3)	($0.0)	($0.0)	($0.0)	0	6
Powerton - Tazewell	Flowgate	Midwest ISO	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	$0.0	$0.0	$0.0	0	2
Pleasant Prairie - Zion	Flowgate	Midwest ISO	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	($0.0)	($0.0)	($0.0)	0	1
Gillespie Tap - Laclede Tap	Flowgate	Midwest ISO	$0.0	$0.0	$0.0	$0.0	$0.1	$0.1	$0.0	($0.0)	($0.0)	0	5
Eau Claire - Arpin	Flowgate	Midwest ISO	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	$0.0	$0.0	0	6

Congestion-Event Summary for the 500 kV System

Constraints on the 500 kV system generally have a regional impact. Table 7-13 and Table 7-14 show the 500 kV constraints impacting congestion costs in PJM. Total congestion costs are the sum of the day-ahead and balancing congestion cost components. Total congestion costs associated with a given constraint may be positive or negative in value. The 500 kV constraints impacting congestion costs in PJM are presented by constraint, in descending order of the absolute value of total congestion costs. In 2007, the Bedington — Black Oak and 5004/5005 interface constraints contributed to positive congestion while the Conemaugh — Hunterstown line contributed to negative congestion. In 2006, the Bedington — Black Oak and 5004/5005 interface constraints contributed to positive congestion. In 2006, no 500 kV zone facilities contributed significantly to negative congestion.

Table 7-13 Regional constraints summary (By facility): Calendar year 2007

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Bedington - Black Oak	Interface	500	$466.3	($227.9)	$43.4	$737.6	$523.6	$531.0	($16.2)	($23.5)	$714.0	5,493	1,836
5004/5005 Interface	Interface	500	$3.4	($111.9)	$5.7	$121.0	($33.9)	($29.6)	($0.3)	($4.6)	$116.5	1,512	386
AP South	Interface	500	$36.9	($57.1)	$4.3	$98.4	$12.5	$10.4	$1.0	$3.1	$101.5	706	133
Kammer	Transformer	500	$31.3	($16.3)	$11.6	$59.2	($39.8)	($48.6)	($3.7)	$5.1	$64.3	2,005	947
Central	Interface	500	($43.7)	($73.5)	$2.5	$32.4	($2.0)	($2.1)	$0.0	$0.0	$32.4	1,334	25
East	Interface	500	($25.2)	($41.9)	$0.8	$17.5	($0.4)	($0.4)	($0.0)	($0.0)	$17.4	304	5
West	Interface	500	$4.1	($13.3)	$2.0	$19.4	($27.0)	($22.3)	($3.6)	($8.4)	$11.0	359	338
Conemaugh - Hunterstown	Line	500	$0.0	$0.0	$0.0	$0.0	($1.5)	($0.9)	($0.0)	($0.7)	($0.7)	0	9
MAAC - Scarcity	Interface	500	$0.0	$0.0	$0.0	$0.0	($5.5)	($4.3)	$1.0	($0.1)	($0.1)	0	3
Alburtis - Branchburg	Line	500	$0.0	$0.0	$0.0	$0.0	($0.1)	($0.1)	$0.0	$0.1	$0.1	0	4
Doubs - Mount Storm	Line	500	$0.0	$0.0	$0.0	$0.0	($0.1)	($0.1)	($0.0)	($0.1)	($0.1)	0	4
Harrison - Pruntytown	Line	500	$0.0	$0.0	$0.0	$0.0	($0.1)	($0.1)	($0.0)	$0.0	$0.0	0	3
Harrison Tap - Kammer	Line	500	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	($0.0)	($0.0)	($0.0)	0	2

Table 7-14 Regional constraints summary (By facility): Calendar year 2006

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Bedington - Black Oak	Interface	500	$1,442.4	$971.9	$15.6	$486.1	$1,113.7	$1,104.9	($3.3)	$5.5	$491.6	3,875	1,812
5004/5005 Interface	Interface	500	($10.7)	($115.5)	$0.6	$105.4	$11.4	$10.4	($0.4)	$0.6	$106.0	1,738	341
AP South	Interface	500	$129.8	$55.5	$1.9	$76.2	$184.2	$178.0	($1.6)	$4.6	$80.8	639	237
West	Interface	500	($0.1)	($54.3)	$1.2	$55.5	($3.8)	($5.6)	($0.9)	$0.9	$56.4	981	328
Kammer	Transformer	500	$79.1	$41.4	$3.9	$41.7	$40.1	$33.5	($0.8)	$5.7	$47.4	2,043	688
Doubs - Mount Storm	Line	500	$66.1	$28.6	$0.5	$38.0	$31.3	$30.0	($0.8)	$0.5	$38.5	240	50
Central	Interface	500	($72.1)	($87.4)	$0.6	$15.8	($1.7)	($1.6)	($0.0)	($0.1)	$15.7	699	15
East	Interface	500	($29.6)	($42.3)	$0.2	$12.9	($1.1)	($1.3)	$0.0	$0.2	$13.1	324	11
Fort Martin - Pruntytown	Line	500	$14.1	$8.5	$0.3	$5.9	$4.1	$4.0	($0.1)	($0.0)	$5.9	111	22
Harrison Tap - Kammer	Line	500	$0.8	$0.3	$0.1	$0.6	$5.2	$4.7	($0.3)	$0.2	$0.7	51	52
Elroy - Hosensack	Line	500	$0.0	$0.0	$0.0	$0.0	$0.4	$0.3	($0.0)	$0.0	$0.0	0	4
Harrison - Harrison Tap	Line	500	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.0	0	3

Congestion on the Bedington — Black Oak and AP South Interfaces

The AP extra-high-voltage (EHV) system is the primary conduit for energy transfers from the AP and midwestern generating resources to southwestern PJM and eastern Virginia load and, to a lesser extent, to the central and eastern portion of the PJM Mid-Atlantic Region. Two AP interface constraints, Bedington — Black Oak and AP South, often restrict west-to-east energy transfers across the AP EHV system. Bedington — Black Oak was the largest contributor to congestion costs of any facility in PJM in calendar year 2007. In 2007, congestion costs associated with the Bedington — Black Oak and AP South interface constraints were $714 million and $101.5 million, respectively. In 2007, the Bedington — Black Oak and AP South interfaces were constrained 5,493 hours and 706 hours day ahead, respectively. The Bedington — Black Oak and AP South interfaces were constrained 1,836 hours and 133 hours in real time in 2007, respectively. In 2006, congestion costs associated with Bedington — Black Oak and AP South were $491.6 million and $80.8 million, respectively. In 2006, Bedington — Black Oak and AP South were constrained 3,875 hours and 639 hours day ahead, respectively. Bedington — Black Oak and AP South were constrained 1,812 hours and 237 hours in real time in 2006, respectively. These results are summarized in Table 7-13 and Table 7-14.

Zonal Congestion

Summary

Day-ahead and balancing congestion costs within specific zones for calendar years 2007 and 2006 are presented in Table 7-15 and Table 7-16. The AP Control Zone, with $448.6 million, incurred the most congestion charges of any control zone in 2007. The leading contributors to congestion in the AP Control Zone in 2007 were the Bedington — Black Oak Interface and the Cloverdale — Lexington line constraints. These two facilities contributed $240.2 and $46.7 million in positive congestion costs, respectively, and together constituted 64 percent of all congestion charges in the AP Control Zone. The Dominion Control Zone incurred the second highest amount of congestion charges in 2007, also driven by congestion on the Bedington — Black Oak Interface and the Cloverdale — Lexington line constraints. These two facilities constituted $99 and $86.4 million in congestion charges, respectively, or 64 percent of the Dominion Control Zone total.

Table 7-15 Congestion cost summary (By control zone): Calendar year 2007

	Congestion Costs (Millions)								
	Day Ahead				Balancing				
Control Zone	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total
AECO	$81.2	$35.6	$0.3	$45.8	$92.3	$90.5	($0.4)	$1.3	$47.1
AEP	($1,369.5)	($1,659.2)	$12.8	$302.6	($1,340.9)	($1,225.8)	($2.0)	($117.1)	$185.5
AP	$72.4	($388.5)	$43.1	$503.9	$14.1	$54.4	($15.0)	($55.3)	$448.6
BGE	$407.4	$358.6	$8.9	$57.7	$498.6	$460.4	($12.5)	$25.8	$83.4
ComEd	($1,569.5)	($1,673.2)	($1.1)	$102.6	($941.7)	($1,019.7)	$0.3	$78.3	$180.9
DAY	($181.0)	($198.8)	($0.1)	$17.8	($185.2)	($178.7)	($0.0)	($6.6)	$11.2
DLCO	($321.6)	($406.9)	($0.0)	$85.2	($200.6)	($158.4)	$0.0	($42.2)	$43.0
Dominion	$920.8	$644.9	$30.8	$306.7	$1,117.0	$1,111.3	($21.6)	($15.9)	$290.8
DPL	$126.4	$61.1	$1.3	$66.6	$134.3	$129.2	($2.2)	$2.9	$69.5
External	($76.3)	($24.3)	$11.0	($40.9)	($11.7)	($31.8)	($74.9)	($54.8)	($95.7)
JCPL	$233.0	$79.0	$4.0	$158.0	$206.9	$198.0	($4.0)	$4.9	$162.9
Met-Ed	$123.5	$92.7	$5.1	$35.9	($0.7)	$10.3	$17.3	$6.3	$42.2
PECO	$451.2	$479.0	$0.7	($27.2)	$15.5	$41.7	($0.9)	($27.0)	($54.2)
PENELEC	($177.6)	($342.7)	$4.5	$169.5	($7.5)	$11.8	($1.3)	($20.6)	$148.9
Pepco	$773.2	$634.7	$13.5	$152.0	$678.8	$622.5	($18.6)	$37.7	$189.6
PPL	$400.1	$410.6	$7.9	($2.6)	$27.6	$32.0	$1.8	($2.6)	($5.3)
PSEG	$371.0	$261.2	$21.1	$130.9	$376.4	$396.3	($24.9)	($44.9)	$86.0
RECO	$10.3	$0.5	$0.5	$10.3	$10.8	$10.5	($0.6)	($0.3)	$9.9
Total	$274.9	($1,635.5)	$164.2	$2,074.6	$484.0	$554.6	($159.5)	($230.1)	$1,844.5

Table 7-16 Congestion cost summary (By control zone): Calendar year 2006

	Congestion Costs (Millions)								
	Day Ahead				Balancing				
Control Zone	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total
AECO	$117.6	$56.5	$0.9	$62.0	$132.1	$126.1	($0.8)	$5.3	$67.2
AEP	($900.0)	($1,176.8)	$25.3	$302.1	($739.2)	($686.2)	($7.4)	($60.4)	$241.7
AP	$90.3	($294.9)	($5.8)	$379.4	$11.3	$48.0	($2.6)	($39.3)	$340.1
BGE	$411.0	$348.4	$1.7	$64.3	$459.2	$416.2	($2.3)	$40.7	$105.0
ComEd	($1,243.8)	($1,298.0)	$33.4	$87.6	($150.8)	($213.2)	($1.0)	$61.3	$149.0
DAY	($131.9)	($148.6)	$5.0	$21.8	($119.3)	($111.2)	($0.0)	($8.1)	$13.6
DLCO	($216.7)	($258.3)	$8.6	$50.2	($137.5)	($115.6)	$0.1	($21.8)	$28.4
Dominion	$977.7	$733.4	$15.1	$259.4	$1,084.7	$1,101.0	($18.4)	($34.7)	$224.7
DPL	$152.6	$80.5	$0.6	$72.7	$149.6	$134.2	($0.9)	$14.5	$87.3
External	($37.2)	($39.3)	($38.1)	($36.0)	$7.0	$10.2	($14.4)	($17.6)	($53.7)
JCPL	$177.5	$84.3	$1.5	$94.8	$144.7	$141.8	($1.8)	$1.1	$95.9
Met-Ed	$141.6	$114.3	$0.0	$27.3	($8.5)	$3.2	($1.5)	($13.2)	$14.2
PECO	$614.1	$641.1	$0.3	($26.7)	$13.9	$41.0	($0.5)	($27.6)	($54.3)
PENELEC	($142.7)	($257.7)	($1.2)	$113.7	($12.3)	($4.0)	($2.0)	($10.3)	$103.4
Pepco	$881.5	$728.4	$2.3	$155.3	$682.3	$652.9	($3.7)	$25.7	$181.0
PPL	$457.5	$486.6	($2.6)	($31.7)	$26.8	$32.9	$0.1	($6.0)	($37.7)
PSEG	$406.8	$335.3	$27.8	$99.4	$434.1	$433.7	($14.2)	($13.9)	$85.6
RECO	$11.4	$0.7	$0.8	$11.5	$12.2	$10.5	($1.3)	$0.5	$12.0
Total	$1,767.2	$135.9	$75.8	$1,707.1	$1,990.3	$2,021.5	($72.6)	($103.8)	$1,603.4

Details of Regional and Zonal Congestion

Constraints were examined by zone and categorized by their effect on regions. Zones correspond to regulated utility franchise areas. Regions generally comprise two or more zones. PJM is comprised of three regions: the PJM Mid-Atlantic Region with 11 control zones (the AECO, BGE, DPL, JCPL, Met-Ed, PECO, PENELEC, Pepco, PPL, PSEG and RECO control zones); the PJM Western Region with five control zones (the AP, ComEd, AEP, DLCO and DAY control zones); and the PJM Southern Region with one control zone (the Dominion Control Zone).

Table 7-17 through Table 7-50 present the top constraints affecting zonal congestion costs by control zone and demonstrate the influence of individual constraints on zonal congestion costs in calendar years 2006 and 2007. For each of these constraints, the zonal cost impacts are decomposed into their Day-Ahead Energy Market and balancing market components. Total congestion costs are the sum of the day-ahead and balancing congestion cost components. Total congestion costs associated with a given constraint may be positive or negative in value. The top constraints affecting zonal congestion costs are presented by constraint, in descending order of the absolute value of total congestion costs. Both day-ahead and real-time, congestion-event hours are presented for each of the highlighted constraints. Constraints can have wide-ranging effects, influencing prices across multiple zones.

Mid-Atlantic Region Congestion-Event Summaries

AECO Control Zone

Table 7-17 and Table 7-18 show the constraints with the largest impacts on total congestion cost in the AECO Control Zone. In 2007, the Beckett — Paulsboro and Bedington — Black Oak constraints were the largest contributors to positive congestion while the Branchburg — Readington and Atlantic — Larrabee lines contributed to negative congestion. All of these constraints are located outside of the AECO Control Zone except for Beckett — Paulsboro. In 2006, the Laurel — Woodstown and Bedington — Black Oak constraints had been the largest contributors to positive congestion while the Cedar Grove — Roseland and Branchburg — Readington constraints contributed to negative congestion.

Table 7-17 AECO Control Zone top congestion cost impacts (By facility): Calendar year 2007

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Beckett - Paulsboro	Line	AECO	$22.3	$6.5	$0.1	$15.9	$21.1	$23.3	($0.0)	($2.2)	$13.7	768	417
Bedington - Black Oak	Interface	500	$18.7	$11.0	$0.0	$7.8	$18.1	$16.5	($0.0)	$1.6	$9.4	5,493	1,836
Branchburg - Readington	Line	PSEG	($9.8)	($6.0)	($0.0)	($3.9)	($15.8)	($14.0)	$0.1	($1.7)	($5.6)	2,324	721
5004/5005 Interface	Interface	500	$11.3	$6.5	$0.1	$4.9	$7.2	$6.8	($0.0)	$0.4	$5.3	1,512	386
Cloverdale - Lexington	Line	AEP	$9.2	$5.6	$0.0	$3.6	$14.3	$12.8	($0.0)	$1.4	$5.0	3,704	1,885
Kammer	Transformer	500	$6.6	$3.9	$0.0	$2.8	$9.7	$8.9	($0.0)	$0.7	$3.5	2,005	947
Central	Interface	500	$6.6	$3.9	$0.0	$2.7	$0.3	$0.3	($0.0)	$0.0	$2.7	1,334	25
Wylie Ridge	Transformer	AP	$4.6	$2.6	$0.1	$2.1	$6.8	$6.1	($0.2)	$0.5	$2.6	1,486	685
Churchtown	Transformer	AECO	($0.7)	($3.4)	($0.2)	$2.6	$0.3	$0.6	$0.2	($0.1)	$2.5	328	194
Atlantic - Larrabee	Line	JCPL	($2.9)	($1.4)	($0.0)	($1.5)	($5.4)	($4.8)	$0.0	($0.5)	($2.0)	680	134
AP South	Interface	500	$3.1	$1.6	$0.0	$1.5	$2.4	$2.2	($0.1)	$0.2	$1.7	706	133
West	Interface	500	$1.9	$1.1	$0.0	$0.8	$6.7	$6.3	($0.0)	$0.4	$1.2	359	338
East	Interface	500	$2.0	$1.1	$0.0	$1.0	$0.1	$0.1	$0.0	$0.0	$1.0	304	5
Cardiff	Transformer	AECO	$0.4	$0.1	$0.0	$0.4	$4.6	$4.1	($0.0)	$0.5	$0.9	26	27
Carlls Corner - Sherman Ave	Line	AECO	$0.4	$0.0	$0.0	$0.4	$0.4	$1.5	($0.0)	($1.2)	($0.8)	182	82

Table 7-18 AECO Control Zone top congestion cost impacts (By facility): Calendar year 2006

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Laurel - Woodstown	Line	AECO	$32.3	$11.7	$0.3	$20.9	$43.9	$46.8	($0.5)	($3.3)	$17.5	2,157	1,203
Bedington - Black Oak	Interface	500	$26.1	$15.0	$0.2	$11.3	$30.9	$27.4	($0.1)	$3.4	$14.7	3,875	1,812
5004/5005 Interface	Interface	500	$13.8	$7.8	$0.1	$6.1	$9.3	$8.1	($0.1)	$1.1	$7.1	1,738	341
Cedar Grove - Roseland	Line	PSEG	($9.1)	($5.0)	($0.0)	($4.1)	($6.4)	($5.5)	$0.0	($0.9)	($5.0)	3,692	541
Mount Storm - Pruntytown	Line	AP	$5.9	$3.1	$0.0	$2.8	$5.5	$5.0	$0.0	$0.5	$3.3	891	465
West	Interface	500	$6.5	$4.2	$0.0	$2.3	$6.1	$5.2	($0.0)	$0.9	$3.2	981	328
Kammer	Transformer	500	$5.8	$3.5	$0.0	$2.3	$5.4	$4.7	($0.0)	$0.7	$3.0	2,043	688
Wylie Ridge	Transformer	AP	$4.1	$2.2	$0.0	$1.9	$7.7	$6.6	($0.0)	$1.0	$2.9	2,286	1,084
Branchburg - Readington	Line	PSEG	($3.0)	($1.6)	$0.0	($1.4)	($9.9)	($8.4)	$0.0	($1.4)	($2.8)	704	480
Cloverdale - Lexington	Line	AEP	$3.2	$1.7	$0.0	$1.4	$9.1	$7.9	($0.0)	$1.1	$2.6	1,517	961
Central	Interface	500	$5.1	$2.8	$0.0	$2.3	$0.2	$0.2	($0.0)	$0.0	$2.4	699	15
AP South	Interface	500	$3.5	$2.0	$0.0	$1.5	$7.1	$6.4	($0.0)	$0.7	$2.2	639	237
Kanawha - Matt Funk	Line	AEP	$3.0	$1.8	$0.0	$1.3	$4.1	$3.6	$0.0	$0.5	$1.8	2,025	617
Deepwater	Transformer	AECO	$1.6	($0.0)	$0.0	$1.7	$3.9	$3.7	($0.1)	$0.1	$1.8	66	67
Carlls Corner - Sherman Ave	Line	AECO	$2.7	$0.9	$0.0	$1.8	$2.8	$2.9	($0.0)	($0.1)	$1.7	712	160

BGE Control Zone

Table 7-19 and Table 7-20 show the constraints with the largest impacts on total congestion cost in the BGE Control Zone. In 2007, the Bedington — Black Oak and Conastone transformer constraints were the largest contributors to positive congestion while the Branchburg — Readington constraint contributed to negative congestion. In 2006, the Bedington — Black Oak and Mount Storm — Pruntytown constraints had been the largest contributors to positive congestion while the Cedar Grove — Roseland and Branchburg — Readington constraints contributed to negative congestion.

Table 7-19 BGE Control Zone top congestion cost impacts (By facility): Calendar year 2007

			Congestion Costs (Millions)									Event Hours	
			Day Ahead				Balancing						
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Bedington - Black Oak	Interface	500	$228.4	$203.7	$4.1	$28.8	$207.1	$190.1	($4.0)	$13.0	$41.8	5,493	1,836
Branchburg - Readington	Line	PSEG	($30.8)	($26.1)	($0.6)	($5.3)	($37.9)	($36.0)	$0.6	($1.3)	($6.6)	2,324	721
Conastone	Transformer	BGE	$12.0	$6.4	($0.1)	$5.6	$15.0	$14.2	$0.0	$0.8	$6.4	172	55
Kammer	Transformer	500	$27.6	$23.2	$1.0	$5.3	$32.6	$30.4	($1.2)	$1.0	$6.3	2,005	947
AP South	Interface	500	$26.7	$22.9	$0.4	$4.2	$18.6	$16.9	($0.2)	$1.4	$5.6	706	133
5004/5005 Interface	Interface	500	$14.9	$10.3	$0.7	$5.4	$6.4	$6.1	($0.3)	($0.0)	$5.4	1,512	386
Cloverdale - Lexington	Line	AEP	$67.9	$71.0	$1.8	($1.3)	$80.0	$72.4	($1.7)	$5.9	$4.6	3,704	1,885
Wylie Ridge	Transformer	AP	$13.9	$11.7	$0.6	$2.8	$15.5	$14.4	($0.8)	$0.4	$3.2	1,486	685
Brunner Island - Yorkana	Line	Met-Ed	$5.8	$4.3	$0.0	$1.5	$16.5	$15.8	($0.2)	$0.6	$2.1	172	196
Bedington	Transformer	AP	$9.7	$8.4	$0.2	$1.6	$9.0	$8.6	($0.2)	$0.2	$1.8	928	429
Aqueduct - Doubs	Line	AP	$5.2	$3.7	$0.0	$1.5	$1.3	$1.2	($0.0)	$0.1	$1.6	262	21
West	Interface	500	$5.5	$4.2	$0.3	$1.7	$16.5	$15.4	($1.4)	($0.3)	$1.4	359	338
Doubs	Transformer	AP	$3.6	$2.3	$0.0	$1.2	$3.8	$3.7	($0.1)	$0.1	$1.3	135	99
Bedington - Nipetown	Line	AP	$3.5	$2.7	$0.1	$0.9	$4.4	$4.1	($0.1)	$0.3	$1.2	841	175
Mount Storm - Pruntytown	Line	AP	$0.6	$0.5	$0.0	$0.0	$12.3	$11.1	($0.1)	$1.1	$1.1	33	151

Table 7-20 BGE Control Zone top congestion cost impacts (By facility): Calendar year 2006

			Congestion Costs (Millions)											
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Bedington - Black Oak	Interface	500	$199.2	$175.5	$0.7	$24.3	$200.4	$178.4	($0.6)	$21.5	$45.7	3,875	1,812
Mount Storm - Pruntytown	Line	AP	$43.6	$39.3	$0.1	$4.4	$33.7	$31.4	($0.0)	$2.4	$6.7	891	465
AP South	Interface	500	$24.1	$20.9	$0.1	$3.3	$40.2	$36.9	($0.1)	$3.1	$6.4	639	237
Aqueduct - Doubs	Line	AP	$17.5	$11.6	$0.1	$5.9	$11.2	$10.7	($0.0)	$0.5	$6.4	362	127
5004/5005 Interface	Interface	500	$13.7	$8.7	$0.1	$5.2	$7.7	$7.4	($0.1)	$0.2	$5.4	1,738	341
Doubs - Mount Storm	Line	500	$15.0	$11.3	$0.0	$3.8	$8.6	$7.3	($0.0)	$1.3	$5.1	240	50
West	Interface	500	$17.7	$14.3	$0.1	$3.5	$13.5	$12.2	($0.2)	$1.1	$4.7	981	328
Kammer	Transformer	500	$23.4	$22.2	$0.1	$1.4	$19.2	$16.1	($0.1)	$3.0	$4.4	2,043	688
Wylie Ridge	Transformer	AP	$12.4	$11.2	$0.1	$1.3	$19.0	$16.5	($0.2)	$2.3	$3.6	2,286	1,084
Cloverdale - Lexington	Line	AEP	$20.2	$21.0	$0.1	($0.7)	$42.9	$38.5	($0.3)	$4.2	$3.4	1,517	961
Doubs	Transformer	AP	$8.2	$5.1	$0.0	$3.1	$5.5	$5.3	($0.0)	$0.2	$3.3	90	74
Cedar Grove - Roseland	Line	PSEG	($29.7)	($27.6)	($0.2)	($2.3)	($15.2)	($14.4)	$0.0	($0.8)	($3.1)	3,692	541
Conastone	Transformer	BGE	$5.3	$2.8	$0.0	$2.5	$8.8	$8.4	($0.0)	$0.3	$2.8	99	27
Branchburg - Readington	Line	PSEG	($10.0)	($9.6)	($0.1)	($0.4)	($22.7)	($20.5)	$0.1	($2.1)	($2.5)	704	480
Kanawha - Matt Funk	Line	AEP	$20.1	$20.8	$0.1	($0.6)	$21.4	$18.1	($0.2)	$3.1	$2.5	2,025	617

DPL Control Zone

Table 7-21 and Table 7-22 show the constraints with the largest impacts on total congestion cost in the DPL Control Zone. In 2007, the Bedington — Black Oak and Cloverdale — Lexington constraints were the largest contributors to positive congestion while the Branchburg — Readington and Atlantic — Larrabee constraints contributed to negative congestion. In 2006, the Bedington — Black Oak and 5004/5005 interface constraints had been the largest contributors to positive congestion while the Cedar Grove — Roseland and Branchburg — Readington constraints contributed to negative congestion.

Table 7-21 DPL Control Zone top congestion cost impacts (By facility): Calendar year 2007

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Bedington - Black Oak	Interface	500	$42.5	$21.7	$0.3	$21.1	$38.2	$35.6	($0.2)	$2.3	$23.4	5,493	1,836
Cloverdale - Lexington	Line	AEP	$19.6	$8.9	$0.2	$10.9	$25.7	$23.3	($0.2)	$2.1	$13.0	3,704	1,885
Branchburg - Readington	Line	PSEG	($20.9)	($10.6)	($0.1)	($10.4)	($28.0)	($26.1)	$0.3	($1.6)	($12.0)	2,324	721
5004/5005 Interface	Interface	500	$21.5	$11.6	$0.2	$10.1	$11.1	$10.9	($0.1)	$0.1	$10.2	1,512	386
Kammer	Transformer	500	$13.1	$6.7	$0.2	$6.6	$17.1	$16.2	($0.2)	$0.7	$7.3	2,005	947
Central	Interface	500	$13.5	$7.1	$0.1	$6.5	$0.5	$0.5	($0.0)	$0.0	$6.5	1,334	25
Wylie Ridge	Transformer	AP	$9.2	$4.6	$0.1	$4.7	$11.6	$10.7	($0.1)	$0.7	$5.4	1,486	685
AP South	Interface	500	$6.6	$3.4	$0.0	$3.2	$4.7	$4.3	($0.0)	$0.3	$3.6	706	133
West	Interface	500	$3.9	$2.0	$0.0	$1.9	$12.2	$11.3	($0.2)	$0.7	$2.7	359	338
East	Interface	500	$4.3	$2.1	$0.0	$2.2	$0.1	$0.1	($0.0)	$0.0	$2.3	304	5
North Seaford	Transformer	DPL	$2.5	$0.6	$0.0	$2.0	$0.5	$0.4	$0.0	$0.0	$2.0	149	7
Atlantic - Larrabee	Line	JCPL	($2.6)	($1.3)	($0.0)	($1.3)	($4.1)	($3.7)	$0.1	($0.3)	($1.6)	680	134
Elrama - Mitchell	Line	AP	$2.4	$1.2	$0.0	$1.2	$4.0	$3.8	($0.0)	$0.2	$1.4	1,883	784
Conastone	Transformer	BGE	($3.3)	($1.9)	($0.0)	($1.5)	($4.7)	($4.8)	$0.0	$0.1	($1.4)	172	55
Cedar Grove - Roseland	Line	PSEG	($2.4)	($1.1)	($0.0)	($1.4)	($0.8)	($0.8)	$0.0	($0.0)	($1.4)	1,677	133

Table 7-22 DPL Control Zone top congestion cost impacts (By facility): Calendar year 2006

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Bedington - Black Oak	Interface	500	$48.4	$26.1	$0.1	$22.4	$56.6	$50.0	($0.1)	$6.5	$28.9	3,875	1,812
5004/5005 Interface	Interface	500	$24.0	$14.1	$0.1	$10.0	$13.0	$12.1	($0.1)	$0.8	$10.8	1,738	341
Cedar Grove - Roseland	Line	PSEG	($15.6)	($7.4)	($0.1)	($8.3)	($9.7)	($8.0)	$0.0	($1.7)	($10.0)	3,692	541
Kammer	Transformer	500	$10.2	$5.2	$0.0	$5.1	$10.5	$8.6	($0.0)	$1.9	$6.9	2,043	688
Wylie Ridge	Transformer	AP	$7.4	$3.7	$0.0	$3.8	$13.3	$10.9	($0.0)	$2.3	$6.1	2,286	1,084
West	Interface	500	$11.3	$6.8	($0.0)	$4.4	$10.7	$9.0	($0.0)	$1.7	$6.1	981	328
Mount Storm - Pruntytown	Line	AP	$10.8	$5.4	$0.0	$5.4	$9.2	$8.6	($0.0)	$0.6	$5.9	891	465
Cloverdale - Lexington	Line	AEP	$6.2	$2.4	$0.0	$3.8	$15.1	$13.1	($0.1)	$1.9	$5.7	1,517	961
Branchburg - Readington	Line	PSEG	($5.5)	($2.7)	$0.0	($2.7)	($16.2)	($13.6)	$0.1	($2.5)	($5.2)	704	480
Central	Interface	500	$9.6	$5.2	$0.1	$4.5	$0.3	$0.3	($0.0)	$0.0	$4.5	699	15
Kanawha - Matt Funk	Line	AEP	$5.5	$2.7	$0.0	$2.8	$7.8	$6.6	($0.0)	$1.1	$3.9	2,025	617
AP South	Interface	500	$6.1	$3.5	$0.0	$2.7	$12.5	$11.2	($0.1)	$1.1	$3.8	639	237
Doubs - Mount Storm	Line	500	$4.4	$2.6	$0.0	$1.8	$2.8	$2.2	($0.0)	$0.5	$2.3	240	50
Mardela - Vienna	Line	DPL	$4.0	$1.6	$0.0	$2.4	$2.7	$3.0	($0.0)	($0.3)	$2.0	236	103
East	Interface	500	$2.8	$1.3	$0.0	$1.5	$0.3	$0.3	$0.0	$0.1	$1.6	324	11

JCPL Control Zone

Table 7-23 and Table 7-24 show the constraints with the largest impacts on total congestion cost in the JCPL Control Zone. In 2007, the Branchburg — Readington and Atlantic — Larrabee constraints were the largest contributors to positive congestion while the Cedar Grove — Roseland constraint contributed to negative congestion. In 2006, the Bedington — Black Oak and 5004/5005 interface constraints had been the largest contributors to positive congestion while the Cedar Grove — Roseland and Branchburg — Readington constraints contributed to negative congestion.

Table 7-23 JCPL Control Zone top congestion cost impacts (By facility): Calendar year 2007

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Branchburg - Readington	Line	PSEG	$33.3	$5.6	$1.5	$29.2	$15.8	$13.5	($1.9)	$0.4	$29.6	2,324	721
Atlantic - Larrabee	Line	JCPL	$27.8	$4.9	$0.5	$23.4	$20.7	$21.5	($0.3)	($1.1)	$22.3	680	134
Bedington - Black Oak	Interface	500	$35.8	$15.9	$0.6	$20.6	$24.0	$23.6	($0.5)	($0.0)	$20.6	5,493	1,836
5004/5005 Interface	Interface	500	$32.7	$14.1	$0.4	$19.0	$16.1	$15.1	($0.1)	$0.9	$19.8	1,512	386
Cloverdale - Lexington	Line	AEP	$23.2	$7.8	$0.4	$15.8	$26.4	$25.5	($0.3)	$0.5	$16.3	3,704	1,885
Kammer	Transformer	500	$17.8	$7.5	$0.2	$10.5	$20.0	$19.3	($0.1)	$0.6	$11.1	2,005	947
Central	Interface	500	$17.0	$6.4	$0.1	$10.7	$0.6	$0.6	($0.0)	$0.1	$10.8	1,334	25
Cedar Grove - Roseland	Line	PSEG	($13.9)	($4.3)	($0.8)	($10.4)	($3.8)	($3.7)	$0.3	$0.1	($10.3)	1,677	133
Branchburg - Flagtown	Line	PSEG	$19.4	$9.7	$0.2	$10.0	$19.6	$19.4	($0.4)	($0.1)	$9.8	580	104
Wylie Ridge	Transformer	AP	$12.2	$5.1	$0.1	$7.1	$14.4	$13.8	($0.1)	$0.6	$7.7	1,486	685
AP South	Interface	500	$7.0	$3.4	$0.2	$3.8	$4.0	$3.9	($0.1)	$0.0	$3.8	706	133
Redoak - Sayreville	Line	JCPL	($0.4)	($3.0)	($0.0)	$2.6	($0.4)	($0.0)	$1.4	$1.1	$3.6	139	33
West	Interface	500	$5.0	$2.1	$0.0	$2.9	$13.7	$12.9	($0.1)	$0.7	$3.6	359	338
Unclassified	Unclassified	Unclassified	$3.3	$0.4	$0.0	$2.9	$0.0	$0.0	$0.0	$0.0	$2.9	NA	NA
East	Interface	500	$4.5	$1.8	$0.0	$2.7	$0.1	$0.1	($0.0)	$0.0	$2.7	304	5

Table 7-24 JCPL Control Zone top congestion cost impacts (By facility): Calendar year 2006

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Bedington - Black Oak	Interface	500	$59.2	$28.4	$0.2	$31.0	$51.4	$49.7	($0.1)	$1.5	$32.5	3,875	1,812
Cedar Grove - Roseland	Line	PSEG	($46.7)	($17.2)	($0.4)	($29.9)	($22.9)	($21.8)	$0.2	($0.9)	($30.8)	3,692	541
5004/5005 Interface	Interface	500	$38.0	$19.1	$0.2	$19.2	$19.6	$18.4	($0.0)	$1.1	$20.3	1,738	341
West	Interface	500	$17.6	$7.3	$0.1	$10.4	$11.6	$11.0	($0.1)	$0.6	$11.0	981	328
Kammer	Transformer	500	$16.1	$7.1	$0.3	$9.3	$10.7	$10.2	($0.0)	$0.5	$9.8	2,043	688
Wylie Ridge	Transformer	AP	$12.3	$5.3	$0.1	$7.2	$15.0	$14.2	($0.0)	$0.8	$7.9	2,286	1,084
Mount Storm - Pruntytown	Line	AP	$12.2	$5.4	($0.0)	$6.7	$8.7	$8.7	($0.0)	($0.0)	$6.7	891	465
Central	Interface	500	$12.0	$5.7	($0.0)	$6.2	$0.3	$0.3	($0.0)	$0.0	$6.3	699	15
Cloverdale - Lexington	Line	AEP	$7.3	$1.9	($0.1)	$5.3	$16.5	$15.7	($0.1)	$0.7	$6.1	1,517	961
Kanawha - Matt Funk	Line	AEP	$9.2	$3.8	$0.1	$5.4	$7.8	$7.3	($0.1)	$0.4	$5.8	2,025	617
AP South	Interface	500	$8.5	$4.4	($0.0)	$4.1	$12.5	$11.9	($0.0)	$0.6	$4.7	639	237
Unclassified	Unclassified	Unclassified	$4.7	$0.6	$0.0	$4.2	$0.0	$0.0	$0.0	$0.0	$4.2	NA	NA
Branchburg - Readington	Line	PSEG	($2.6)	($2.1)	$0.7	$0.2	($10.4)	($7.5)	($1.4)	($4.3)	($4.1)	704	480
Doubs - Mount Storm	Line	500	$5.7	$3.2	($0.0)	$2.6	$2.3	$2.5	($0.0)	($0.2)	$2.3	240	50
East	Interface	500	$2.9	$0.9	$0.0	$2.0	$0.3	$0.3	($0.0)	$0.0	$2.0	324	11

Met-Ed Control Zone

Table 7-25 and Table 7-26 show the constraints with the largest impacts on total congestion cost in the Met-Ed Control Zone. In 2007, the Brunner Island — Yorkana and Bedington — Black Oak constraints were the largest contributors to positive congestion while the Branchburg — Readington and Central interface constraints contributed to negative congestion. In 2006, the Hunterstown and Jackson transformer constraints had been the largest contributors to positive congestion while the AP South, Cedar Grove — Roseland and Aqueduct — Doubs constraints contributed to negative congestion.

Table 7-25 Met-Ed Control Zone top congestion cost impacts (By facility): Calendar year 2007

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Brunner Island - Yorkana	Line	Met-Ed	$4.2	($3.1)	$0.0	$7.4	$0.1	$0.0	$0.6	$0.6	$8.1	172	196
Bedington - Black Oak	Interface	500	$35.3	$31.8	$1.8	$5.2	($0.4)	$1.5	$4.1	$2.3	$7.5	5,493	1,836
Hunterstown	Transformer	Met-Ed	$8.5	$2.5	$0.3	$6.3	($0.1)	$0.9	$1.0	($0.1)	$6.2	345	139
Jackson	Transformer	Met-Ed	$5.5	$0.1	$0.1	$5.5	($0.2)	$1.6	$1.1	($0.7)	$4.8	155	114
Gardners - Hunterstown	Line	Met-Ed	$2.2	($1.2)	$0.1	$3.4	($0.2)	$0.6	$0.4	($0.4)	$3.0	953	271
5004/5005 Interface	Interface	500	$18.4	$17.1	$0.6	$2.0	($0.1)	$0.6	$1.3	$0.5	$2.5	1,512	386
Kammer	Transformer	500	$11.6	$12.0	$0.9	$0.5	$0.0	$0.2	$1.7	$1.5	$2.0	2,005	947
Bedington	Transformer	AP	$2.0	$0.8	$0.0	$1.3	($0.0)	$0.1	$0.8	$0.6	$1.9	928	429
Branchburg - Readington	Line	PSEG	($13.0)	($10.5)	($0.0)	($2.5)	$0.3	($0.7)	$0.1	$1.0	($1.5)	2,324	721
Conastone	Transformer	BGE	$0.2	($0.8)	$0.0	$1.1	$0.0	$0.2	($0.1)	($0.2)	$0.9	172	55
Cloverdale - Lexington	Line	AEP	$17.3	$15.3	$0.2	$2.1	($0.5)	$1.2	$0.4	($1.3)	$0.8	3,704	1,885
Central	Interface	500	$5.3	$6.2	$0.1	($0.7)	$0.0	$0.0	$0.0	$0.0	($0.7)	1,334	25
AP South	Interface	500	$5.4	$5.6	$0.3	$0.1	$0.1	$0.4	$0.9	$0.6	$0.7	706	133
MAAC - Scarcity	Interface	500	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	$0.6	$0.6	$0.6	0	3
Doubs	Transformer	AP	$0.6	$0.3	$0.1	$0.4	($0.1)	$0.0	$0.2	$0.2	$0.5	135	99

Table 7-26 Met-Ed Control Zone top congestion cost impacts (By facility): Calendar year 2006

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Hunterstown	Transformer	Met-Ed	$9.5	$2.7	($0.0)	$6.8	$0.0	$0.3	$0.0	($0.2)	$6.6	303	66
Jackson	Transformer	Met-Ed	$5.0	$0.9	$0.0	$4.1	($0.0)	($0.0)	($0.0)	($0.0)	$4.1	117	54
West	Interface	500	$11.8	$9.8	$0.3	$2.3	($0.2)	($0.1)	($0.2)	($0.2)	$2.0	981	328
5004/5005 Interface	Interface	500	$20.9	$17.1	($1.0)	$2.8	($1.1)	($0.1)	($0.0)	($1.1)	$1.7	1,738	341
Gardners - Hunterstown	Line	Met-Ed	$1.4	($0.3)	($0.0)	$1.7	($0.3)	$0.4	$0.0	($0.7)	$1.0	496	257
AP South	Interface	500	$6.6	$6.2	$0.0	$0.4	($1.4)	($0.1)	($0.1)	($1.4)	($0.9)	639	237
Kammer	Transformer	500	$11.6	$10.1	$0.3	$1.8	($0.5)	$0.1	($0.3)	($0.8)	$0.9	2,043	688
Cedar Grove - Roseland	Line	PSEG	($19.0)	($17.5)	($0.2)	($1.6)	$0.9	$0.2	$0.0	$0.8	($0.9)	3,692	541
Aqueduct - Doubs	Line	AP	$0.8	$1.4	$0.0	($0.6)	($0.2)	($0.0)	($0.1)	($0.2)	($0.9)	362	127
Middletown Jct	Transformer	Met-Ed	$1.1	$0.2	$0.0	$0.9	$0.1	$0.1	($0.0)	($0.0)	$0.9	25	16
Cloverdale - Lexington	Line	AEP	$5.7	$5.2	$0.0	$0.6	($0.6)	$0.5	($0.2)	($1.4)	($0.9)	1,517	961
Mount Storm - Pruntytown	Line	AP	$9.6	$9.3	$0.0	$0.3	($0.9)	$0.2	($0.1)	($1.1)	($0.7)	891	465
Middletown Jct - S Lebanon	Line	Met-Ed	$0.7	$0.0	$0.0	$0.7	$0.0	$0.0	$0.0	$0.0	$0.7	15	0
Doubs - Mount Storm	Line	500	$4.1	$4.2	$0.0	($0.2)	($0.5)	$0.0	($0.0)	($0.5)	($0.7)	240	50
Brunner Island - Yorkana	Line	Met-Ed	$0.1	($0.3)	$0.0	$0.4	$0.3	$0.1	($0.0)	$0.2	$0.6	19	34

PECO Control Zone

Table 7-27 and Table 7-28 show the constraints with the largest impacts on total congestion cost in the PECO Control Zone. In 2007, the Branchburg — Readington and East interface constraints were the largest contributors to positive congestion while the Bedington — Black Oak and Cloverdale — Lexington constraints contributed to negative congestion. In 2006, the Whitpain transformer and Cedar Grove — Roseland constraints had been the largest contributors to positive congestion while the Bedington — Black Oak and 5004/5005 interface constraints contributed to negative congestion.

Table 7-27 PECO Control Zone top congestion cost impacts (By facility): Calendar year 2007

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Bedington - Black Oak	Interface	500	$152.8	$173.9	$0.2	($20.9)	$2.4	$9.4	$0.0	($6.9)	($27.9)	5,493	1,836
Cloverdale - Lexington	Line	AEP	$78.0	$82.0	$0.1	($3.9)	$5.4	$10.2	($0.1)	($5.0)	($8.9)	3,704	1,885
5004/5005 Interface	Interface	500	$89.1	$95.2	$0.1	($6.0)	$1.0	$3.3	($0.0)	($2.4)	($8.3)	1,512	386
Branchburg - Readington	Line	PSEG	($92.6)	($97.2)	($0.0)	$4.6	($0.4)	($3.9)	($0.2)	$3.2	$7.8	2,324	721
Kammer	Transformer	500	$54.0	$57.4	$0.1	($3.3)	$1.4	$5.1	($0.1)	($3.8)	($7.1)	2,005	947
East	Interface	500	$15.2	$10.0	($0.0)	$5.2	($0.0)	($0.0)	$0.0	($0.0)	$5.2	304	5
AP South	Interface	500	$24.7	$28.8	$0.0	($4.1)	$0.1	$1.1	$0.0	($1.0)	($5.0)	706	133
Wylie Ridge	Transformer	AP	$38.1	$40.3	$0.0	($2.2)	$1.4	$3.9	($0.1)	($2.6)	($4.8)	1,486	685
Plymouth Meeting - Whitpain	Line	PECO	$12.4	$7.6	$0.0	$4.8	$0.4	$1.1	$0.0	($0.6)	$4.1	55	34
Central	Interface	500	$51.6	$55.5	$0.1	($3.7)	$0.1	$0.2	($0.0)	($0.1)	($3.8)	1,334	25
West	Interface	500	$16.4	$17.7	$0.0	($1.3)	$0.7	$3.0	($0.0)	($2.3)	($3.6)	359	338
Conastone	Transformer	BGE	($10.1)	($12.9)	($0.0)	$2.8	$0.3	$0.1	$0.0	$0.3	$3.1	172	55
Elrama - Mitchell	Line	AP	$10.1	$11.0	$0.0	($0.9)	$0.9	$1.6	($0.0)	($0.7)	($1.6)	1,883	784
Loudoun - Morrisville	Line	Dominion	$2.6	$2.9	$0.0	($0.3)	$0.1	$1.3	($0.0)	($1.2)	($1.5)	74	93
Brunner Island - Yorkana	Line	Met-Ed	($6.3)	($6.6)	($0.0)	$0.3	$0.1	($1.0)	$0.0	$1.0	$1.4	172	196

Table 7-28 PECO Control Zone top congestion cost impacts (By facility): Calendar year 2006

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Bedington - Black Oak	Interface	500	$203.9	$226.0	($0.0)	($22.1)	$2.6	$13.7	($0.0)	($11.2)	($33.3)	3,875	1,812
Whitpain	Transformer	PECO	$24.0	$7.8	$0.2	$16.5	$0.9	$3.3	($0.3)	($2.7)	$13.7	193	125
5004/5005 Interface	Interface	500	$106.0	$113.4	$0.0	($7.4)	$0.7	$2.8	($0.0)	($2.2)	($9.6)	1,738	341
Cedar Grove - Roseland	Line	PSEG	($78.1)	($81.9)	$0.0	$3.8	($0.6)	($3.2)	($0.0)	$2.6	$6.4	3,692	541
AP South	Interface	500	$27.9	$31.8	($0.0)	($4.0)	$0.3	$2.7	($0.0)	($2.4)	($6.4)	639	237
West	Interface	500	$56.5	$60.9	($0.0)	($4.3)	$0.2	$2.1	($0.0)	($1.9)	($6.2)	981	328
Kammer	Transformer	500	$51.2	$55.5	($0.1)	($4.4)	$0.9	$2.6	($0.0)	($1.7)	($6.1)	2,043	688
Wylie Ridge	Transformer	AP	$36.7	$40.3	$0.0	($3.6)	$1.6	$3.7	($0.0)	($2.1)	($5.7)	2,286	1,084
Mount Storm - Pruntytown	Line	AP	$43.2	$46.1	($0.1)	($3.0)	$1.0	$2.7	($0.0)	($1.7)	($4.7)	891	465
Kanawha - Matt Funk	Line	AEP	$27.3	$30.0	($0.0)	($2.7)	$1.1	$2.6	($0.0)	($1.5)	($4.2)	2,025	617
Branchburg - Readington	Line	PSEG	($28.2)	($30.1)	($0.0)	$1.9	($0.2)	($2.4)	$0.0	$2.2	$4.1	704	480
Central	Interface	500	$36.3	$40.1	$0.0	($3.7)	$0.0	$0.1	($0.0)	($0.1)	($3.8)	699	15
East	Interface	500	$10.1	$6.4	$0.0	$3.7	$0.1	$0.0	($0.0)	$0.0	$3.8	324	11
Cloverdale - Lexington	Line	AEP	$26.6	$26.4	$0.0	$0.2	$3.9	$6.9	($0.0)	($3.0)	($2.8)	1,517	961
Doubs - Mount Storm	Line	500	$17.9	$19.7	$0.0	($1.8)	$0.1	$0.8	$0.0	($0.7)	($2.6)	240	50

PENELEC Control Zone

Table 7-29 and Table 7-30 show the constraints with the largest impacts on total congestion cost in the PENELEC Control Zone. In 2007, the Bedington — Black Oak and 5004/5005 interface constraints were the largest contributors to positive congestion while the Wylie Ridge and Kammer transformer constraints contributed to negative congestion. In 2006, the 5004/5005 Interface and Bedington — Black Oak constraints had been the largest contributors to positive congestion while the Wylie Ridge and Kammer transformer constraints contributed to negative congestion.

Table 7-29 PENELEC Control Zone top congestion cost impacts (By facility): Calendar year 2007

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Bedington - Black Oak	Interface	500	($137.7)	($221.0)	$0.0	$83.4	($8.4)	$0.1	$0.4	($8.1)	$75.2	5,493	1,836
5004/5005 Interface	Interface	500	($36.9)	($84.5)	($1.0)	$46.6	($0.6)	$0.7	$0.4	($0.9)	$45.6	1,512	386
Wylie Ridge	Transformer	AP	$21.6	$41.5	$1.0	($18.9)	$2.7	($0.3)	($0.9)	$2.1	($16.9)	1,486	685
Kammer	Transformer	500	$26.4	$47.2	$1.5	($19.3)	$2.3	($0.7)	($0.5)	$2.5	($16.8)	2,005	947
Branchburg - Readington	Line	PSEG	($23.7)	($42.5)	($0.0)	$18.8	($5.4)	($0.3)	$0.2	($4.8)	$14.0	2,324	721
Central	Interface	500	($8.0)	($20.9)	($0.1)	$12.8	($0.0)	$0.0	$0.0	($0.0)	$12.8	1,334	25
Bedington	Transformer	AP	($8.4)	($14.8)	$0.0	$6.5	$0.2	$0.1	$0.1	$0.3	$6.8	928	429
Elrama - Mitchell	Line	AP	$6.5	$12.6	$0.3	($5.9)	$0.6	($0.4)	($0.2)	$0.7	($5.1)	1,883	784
AP South	Interface	500	($8.7)	($13.4)	$0.3	$4.9	$0.1	$0.0	($0.1)	($0.1)	$4.9	706	133
Cloverdale - Lexington	Line	AEP	$2.6	$8.1	$1.7	($3.8)	$1.6	$0.2	($1.6)	($0.3)	($4.0)	3,704	1,885
Seward	Transformer	PENELEC	$10.4	$7.0	$0.0	$3.5	$0.2	$0.1	$0.0	$0.1	$3.6	110	3
West	Interface	500	($4.7)	($10.6)	$0.0	$5.9	($0.7)	$1.7	$0.1	($2.3)	$3.6	359	338
East Towanda	Transformer	PENELEC	$7.5	($4.3)	$0.3	$12.1	($1.0)	$7.9	$0.1	($8.9)	$3.3	1,055	410
East	Interface	500	($3.8)	($6.6)	($0.0)	$2.8	($0.0)	($0.0)	($0.0)	($0.0)	$2.8	304	5
Bear Rock - Johnstown	Line	PENELEC	($3.6)	($5.8)	($0.0)	$2.1	$0.1	$0.2	$0.0	($0.1)	$2.0	212	21

Table 7-30 PENELEC Control Zone top congestion cost impacts (By facility): Calendar year 2006

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
5004/5005 Interface	Interface	500	($51.4)	($97.4)	($0.2)	$45.9	($1.3)	($0.5)	$0.0	($0.8)	$45.1	1,738	341
Bedington - Black Oak	Interface	500	($49.2)	($73.8)	($0.4)	$24.2	($4.2)	($3.8)	$0.1	($0.3)	$23.8	3,875	1,812
Cedar Grove - Roseland	Line	PSEG	($44.6)	($65.7)	($0.2)	$20.8	($2.4)	($2.4)	($0.0)	($0.1)	$20.7	3,692	541
Wylie Ridge	Transformer	AP	$27.5	$45.7	$0.3	($17.9)	$3.0	$3.5	($0.9)	($1.4)	($19.3)	2,286	1,084
West	Interface	500	($21.2)	($39.6)	($0.2)	$18.1	($0.5)	($0.1)	$0.0	($0.4)	$17.7	981	328
Kammer	Transformer	500	$31.6	$47.5	$0.2	($15.7)	$1.9	$1.9	($0.3)	($0.2)	($15.9)	2,043	688
Central	Interface	500	($10.6)	($19.5)	$0.1	$8.9	($0.0)	$0.0	($0.0)	($0.0)	$8.9	699	15
Branchburg - Readington	Line	PSEG	($14.6)	($21.4)	($0.0)	$6.8	($2.1)	($2.5)	$0.0	$0.5	$7.3	704	480
Seward	Transformer	PENELEC	$25.8	$19.7	($0.1)	$6.0	$0.2	$0.3	($0.0)	($0.1)	$5.9	258	11
Kanawha - Matt Funk	Line	AEP	$8.3	$12.8	$0.0	($4.4)	$0.5	$1.1	($0.2)	($0.8)	($5.2)	2,025	617
Mount Storm - Pruntytown	Line	AP	($9.4)	($14.1)	($0.0)	$4.7	($0.7)	($0.6)	$0.0	($0.1)	$4.6	891	465
Goudey - Laurel Lake	Line	PENELEC	$0.1	$0.0	$0.0	$0.0	($3.4)	$0.8	($0.3)	($4.4)	($4.4)	13	53
Cloverdale - Lexington	Line	AEP	$5.7	$9.6	($0.0)	($3.9)	$1.1	$1.0	$0.0	$0.2	($3.7)	1,517	961
Bedington	Transformer	AP	($1.7)	($4.4)	($0.0)	$2.6	($0.5)	($0.7)	$0.0	$0.2	$2.8	662	451
Altoona - Johnstown	Line	PENELEC	($8.0)	($10.6)	($0.0)	$2.5	($0.1)	$0.1	$0.0	($0.1)	$2.4	107	8

Pepco Control Zone

Table 7-31 and Table 7-32 show the constraints with the largest impacts on total congestion cost in the Pepco Control Zone. In 2007, the Bedington — Black Oak and Cloverdale — Lexington constraints were the largest contributors to positive congestion while the Branchburg —Readington and Central interface constraints contributed to negative congestion. In 2006, the Bedington — Black Oak and Mount Storm — Pruntytown constraints had been the largest contributors to positive congestion while the Cedar Grove — Roseland and Branchburg — Readington constraints contributed to negative congestion.

Table 7-31 Pepco Control Zone top congestion cost impacts (By facility): Calendar year 2007

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Bedington - Black Oak	Interface	500	$455.4	$381.3	$5.6	$79.7	$312.9	$284.9	($5.1)	$22.9	$102.6	5,493	1,836
Cloverdale - Lexington	Line	AEP	$136.7	$114.8	$2.0	$23.9	$121.1	$105.0	($2.3)	$13.8	$37.7	3,704	1,885
Kammer	Transformer	500	$47.3	$38.3	$0.7	$9.6	$40.9	$37.3	($0.9)	$2.6	$12.3	2,005	947
AP South	Interface	500	$50.4	$41.3	$0.7	$9.9	$26.2	$24.6	($0.2)	$1.4	$11.3	706	133
Branchburg - Readington	Line	PSEG	($49.8)	($44.3)	($0.2)	($5.8)	($46.8)	($41.1)	$0.4	($5.3)	($11.1)	2,324	721
Wylie Ridge	Transformer	AP	$20.3	$17.2	$0.6	$3.7	$17.9	$15.7	($0.6)	$1.6	$5.4	1,486	685
Bedington	Transformer	AP	$20.6	$16.5	$1.2	$5.3	$16.5	$15.6	($1.0)	($0.1)	$5.1	928	429
Aqueduct - Doubs	Line	AP	$16.0	$11.9	$0.3	$4.3	$2.9	$2.9	($0.1)	($0.0)	$4.3	262	21
5004/5005 Interface	Interface	500	$11.6	$9.0	$0.3	$2.9	$3.0	$2.8	($0.1)	$0.1	$3.0	1,512	386
Central	Interface	500	($20.0)	($17.2)	($0.1)	($2.9)	($0.4)	($0.4)	$0.0	($0.0)	($3.0)	1,334	25
Doubs	Transformer	AP	$12.1	$9.3	$0.2	$3.1	$10.7	$10.7	($0.6)	($0.7)	$2.4	135	99
Brunner Island - Yorkana	Line	Met-Ed	$6.5	$5.2	$0.3	$1.6	$17.0	$15.7	($0.8)	$0.5	$2.1	172	196
Bedington - Nipetown	Line	AP	$6.9	$5.7	$0.1	$1.3	$6.2	$5.5	($0.0)	$0.7	$1.9	841	175
Mount Storm - Pruntytown	Line	AP	$1.2	$1.0	$0.0	$0.2	$19.9	$18.1	($0.3)	$1.5	$1.7	33	151
Elrama - Mitchell	Line	AP	$5.8	$4.6	$0.2	$1.3	$7.5	$6.8	($0.4)	$0.4	$1.7	1,883	784

Table 7-32 Pepco Control Zone top congestion cost impacts (By facility): Calendar year 2006

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Bedington - Black Oak	Interface	500	$434.0	$363.1	$1.3	$72.2	$291.8	$277.3	($1.0)	$13.5	$85.7	3,875	1,812
Mount Storm - Pruntytown	Line	AP	$95.0	$79.9	$0.4	$15.4	$53.1	$51.8	($0.2)	$1.0	$16.5	891	465
AP South	Interface	500	$51.8	$41.2	$0.2	$10.8	$60.9	$57.8	($0.4)	$2.7	$13.5	639	237
Cloverdale - Lexington	Line	AEP	$45.0	$37.6	$0.0	$7.4	$65.3	$61.1	($0.2)	$4.0	$11.4	1,517	961
Cedar Grove - Roseland	Line	PSEG	($57.4)	($47.7)	($0.3)	($10.0)	($20.4)	($19.7)	$0.1	($0.6)	($10.6)	3,692	541
Aqueduct - Doubs	Line	AP	$54.0	$43.5	$0.1	$10.6	$25.4	$25.6	($0.2)	($0.4)	$10.3	362	127
Kammer	Transformer	500	$46.5	$38.6	$0.1	$8.0	$23.4	$21.5	($0.1)	$1.8	$9.8	2,043	688
Kanawha - Matt Funk	Line	AEP	$45.7	$38.0	$0.2	$7.9	$28.8	$27.3	($0.1)	$1.4	$9.3	2,025	617
Doubs - Mount Storm	Line	500	$29.6	$25.0	($0.1)	$4.6	$13.1	$11.7	($0.0)	$1.4	$6.0	240	50
Doubs	Transformer	AP	$33.2	$27.3	($0.0)	$5.9	$13.2	$13.2	($0.1)	($0.1)	$5.8	90	74
Wylie Ridge	Transformer	AP	$22.1	$18.0	$0.1	$4.2	$21.8	$20.7	($0.3)	$0.8	$5.0	2,286	1,084
West	Interface	500	$18.8	$15.4	$0.0	$3.4	$8.2	$7.9	($0.1)	$0.2	$3.6	981	328
Bedington	Transformer	AP	$14.6	$11.6	$0.2	$3.3	$24.4	$23.9	($0.3)	$0.2	$3.5	662	451
Dickerson - Doubs	Line	Pepco	$17.5	$14.2	($0.0)	$3.3	$2.9	$2.8	($0.0)	$0.1	$3.4	116	11
Branchburg - Readington	Line	PSEG	($19.6)	($16.8)	($0.0)	($2.8)	($28.7)	($28.1)	$0.1	($0.6)	($3.3)	704	480

PPL Control Zone

Table 7-33 and Table 7-34 show the constraints with the largest impacts on total congestion cost in the PPL Control Zone. In 2007, the Bedington — Black Oak and Brunner Island — Yorkana constraints were the largest contributors to positive congestion while the 5004/5005 Interface and Cloverdale — Lexington constraints contributed to negative congestion. In 2006, the Cedar Grove — Roseland and East interface constraints had been the largest contributors to positive congestion while the 5004/5005 and Bedington — Black Oak constraints contributed to negative congestion.

Table 7-33 PPL Control Zone top congestion cost impacts (By facility): Calendar year 2007

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
5004/5005 Interface	Interface	500	$91.9	$102.7	$1.2	($9.6)	$2.5	$3.1	($0.2)	($0.7)	($10.3)	1,512	386
Bedington - Black Oak	Interface	500	$109.1	$105.7	$2.2	$5.6	$6.2	$6.7	$1.1	$0.6	$6.3	5,493	1,836
Cloverdale - Lexington	Line	AEP	$67.4	$75.3	$1.5	($6.5)	$5.5	$5.5	$0.5	$0.5	($6.0)	3,704	1,885
Central	Interface	500	$35.1	$40.3	$0.5	($4.6)	$0.1	$0.1	$0.0	$0.0	($4.6)	1,334	25
Brunner Island - Yorkana	Line	Met-Ed	($10.3)	($15.1)	($0.1)	$4.7	($1.9)	($0.6)	($0.0)	($1.3)	$3.5	172	196
Branchburg - Readington	Line	PSEG	($52.1)	($57.2)	($0.2)	$4.9	($3.8)	($3.4)	($1.2)	($1.6)	$3.2	2,324	721
Kammer	Transformer	500	$48.9	$53.1	$0.8	($3.4)	$4.0	$4.1	$0.4	$0.3	($3.1)	2,005	947
Manor - Safe Harbor	Line	Met-Ed	$4.1	$1.3	$0.0	$2.8	$0.0	$0.0	$0.0	$0.0	$2.8	95	0
Conastone	Transformer	BGE	$0.2	($2.5)	($0.0)	$2.7	$0.1	$0.1	($0.0)	($0.0)	$2.7	172	55
Wylie Ridge	Transformer	AP	$37.1	$41.0	$0.6	($3.2)	$3.0	$2.5	($0.0)	$0.5	($2.7)	1,486	685
East	Interface	500	($2.0)	($4.1)	($0.0)	$2.1	$0.0	$0.0	($0.0)	($0.0)	$2.1	304	5
Cedar Grove - Roseland	Line	PSEG	($15.3)	($17.1)	($0.1)	$1.7	($0.3)	($0.3)	$0.0	($0.1)	$1.6	1,677	133
West	Interface	500	$15.3	$16.4	$0.2	($0.9)	$2.7	$3.4	$0.2	($0.6)	($1.5)	359	338
PL North	Interface	PPL	$0.0	$0.0	$0.0	$0.0	($0.9)	$0.3	($0.1)	($1.3)	($1.3)	0	93
Elrama - Mitchell	Line	AP	$9.3	$10.5	$0.2	($1.1)	$0.8	$1.0	$0.0	($0.2)	($1.3)	1,883	784

Table 7-34 PPL Control Zone top congestion cost impacts (By facility): Calendar year 2006

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
5004/5005 Interface	Interface	500	$100.5	$112.9	($0.8)	($13.2)	$3.7	$4.9	$0.2	($1.0)	($14.2)	1,738	341
Bedington - Black Oak	Interface	500	$154.6	$161.2	($0.7)	($7.2)	$10.5	$12.3	$0.5	($1.2)	($8.4)	3,875	1,812
Cedar Grove - Roseland	Line	PSEG	($82.3)	($89.6)	$0.3	$7.6	($3.1)	($3.4)	($0.3)	($0.0)	$7.6	3,692	541
West	Interface	500	$52.8	$57.0	($0.4)	($4.5)	$2.5	$2.3	($0.0)	$0.2	($4.3)	981	328
Central	Interface	500	$20.6	$24.7	($0.1)	($4.2)	$0.1	$0.1	$0.0	($0.0)	($4.2)	699	15
Wylie Ridge	Transformer	AP	$35.4	$38.1	($0.2)	($2.8)	$3.5	$4.3	$0.2	($0.6)	($3.4)	2,286	1,084
Cloverdale - Lexington	Line	AEP	$21.4	$24.8	($0.1)	($3.5)	$3.9	$3.9	$0.2	$0.2	($3.3)	1,517	961
Kanawha - Matt Funk	Line	AEP	$25.9	$28.1	($0.2)	($2.4)	$1.7	$2.5	$0.0	($0.8)	($3.2)	2,025	617
Kammer	Transformer	500	$47.7	$50.0	($0.4)	($2.6)	$2.5	$2.7	$0.1	($0.2)	($2.9)	2,043	688
Mount Storm - Pruntytown	Line	AP	$30.1	$32.4	($0.2)	($2.5)	$1.7	$2.1	$0.0	($0.4)	($2.8)	891	465
AP South	Interface	500	$22.1	$23.3	($0.0)	($1.2)	$2.3	$3.1	$0.1	($0.6)	($1.9)	639	237
East	Interface	500	($1.9)	($3.6)	($0.0)	$1.6	($0.0)	($0.0)	($0.0)	($0.0)	$1.6	324	11
Branchburg - Readington	Line	PSEG	($21.5)	($23.7)	$0.1	$2.2	($3.6)	($3.4)	($0.7)	($0.9)	$1.3	704	480
Doubs - Mount Storm	Line	500	$12.6	$13.6	($0.0)	($1.0)	$0.6	$0.8	$0.0	($0.1)	($1.1)	240	50
Conastone	Transformer	BGE	$1.4	$0.8	$0.0	$0.6	$0.2	($0.0)	$0.1	$0.3	$0.9	99	27

PSEG Control Zone

Table 7-35 and Table 7-36 show the constraints with the largest impacts on total congestion cost in the PSEG Control Zone. In 2007, the Branchburg — Readington and Cedar Grove — Roseland constraints were the largest contributors to positive congestion while the Bedington — Black Oak and South Mahwah — Waldwick constraints contributed to negative congestion. In 2006, the Cedar Grove — Roseland and 5004/5005 interface constraints had been the largest contributors to positive congestion while the Cedar Grove — Clifton and South Mahwah — Waldwick constraints contributed to negative congestion.

Table 7-35 PSEG Control Zone top congestion cost impacts (By facility): Calendar year 2007

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Branchburg - Readington	Line	PSEG	$42.2	($8.7)	$0.3	$51.2	$56.6	$65.5	($2.5)	($11.4)	$39.8	2,324	721
Cedar Grove - Roseland	Line	PSEG	$17.6	$3.7	($0.3)	$13.6	$5.6	$5.8	($0.1)	($0.4)	$13.2	1,677	133
Branchburg - Flagtown	Line	PSEG	$11.4	$1.5	$0.3	$10.2	$16.7	$16.4	($0.8)	($0.5)	$9.7	580	104
Bedington - Black Oak	Interface	500	$59.1	$67.4	$5.0	($3.3)	$39.4	$41.6	($3.2)	($5.3)	($8.6)	5,493	1,836
Atlantic - Larrabee	Line	JCPL	$6.8	($2.6)	$0.2	$9.6	$11.6	$12.3	($0.6)	($1.4)	$8.2	680	134
South Mahwah - Waldwick	Line	PSEG	$3.9	$2.3	($0.9)	$0.7	$15.6	$18.6	($4.9)	($8.0)	($7.3)	304	58
5004/5005 Interface	Interface	500	$49.7	$45.9	$2.0	$5.7	$27.4	$27.0	($0.7)	($0.3)	$5.4	1,512	386
Brunswick - Edison	Line	PSEG	$4.9	$0.7	$0.2	$4.4	$2.1	$2.0	($0.1)	($0.0)	$4.4	667	125
Edison - Meadow Rd	Line	PSEG	$4.0	$0.6	$0.3	$3.7	$4.0	$3.9	($0.2)	($0.2)	$3.5	438	143
Wylie Ridge	Transformer	AP	$21.5	$18.8	$1.0	$3.6	$24.2	$24.9	($0.9)	($1.7)	$1.9	1,486	685
Linden - North Ave	Line	PSEG	$1.1	($0.6)	$0.1	$1.7	$0.0	$0.0	($0.0)	$0.0	$1.7	421	1
Cloverdale - Lexington	Line	AEP	$39.8	$39.4	$2.3	$2.7	$45.4	$47.9	($1.9)	($4.3)	($1.6)	3,704	1,885
Central	Interface	500	$27.8	$27.1	$0.9	$1.6	$1.1	$1.1	($0.0)	$0.0	$1.6	1,334	25
Bergen - Hoboken	Line	PSEG	$0.5	($0.3)	$0.7	$1.5	$0.0	$0.0	($0.0)	$0.0	$1.5	210	9
Athenia - Saddlebrook	Line	PSEG	$1.3	$1.0	$0.9	$1.2	$1.0	$1.0	$0.0	$0.0	$1.2	173	15

Table 7-36 PSEG Control Zone top congestion cost impacts (By facility): Calendar year 2006

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Cedar Grove - Roseland	Line	PSEG	$11.6	($17.2)	($0.3)	$28.5	$6.4	$8.7	($0.4)	($2.7)	$25.8	3,692	541
5004/5005 Interface	Interface	500	$59.4	$55.5	$4.1	$8.1	$35.8	$33.6	($0.6)	$1.6	$9.6	1,738	341
Edison - Meadow Rd	Line	PSEG	$9.7	$1.5	$0.7	$9.0	$15.4	$15.1	($0.8)	($0.5)	$8.4	875	634
Branchburg - Readington	Line	PSEG	$4.2	($5.5)	$0.2	$10.0	$11.0	$12.5	($0.7)	($2.2)	$7.8	704	480
Bergen - Hoboken	Line	PSEG	$0.4	($1.6)	$2.8	$4.8	($0.1)	($0.1)	($0.1)	($0.1)	$4.7	681	108
Cedar Grove - Clifton	Line	PSEG	$1.0	$0.0	$0.4	$1.3	$20.0	$22.8	($2.4)	($5.2)	($3.9)	168	536
Brunswick - Edison	Line	PSEG	$3.6	$0.5	$0.3	$3.3	$3.1	$3.0	($0.2)	($0.1)	$3.3	464	206
Bergen - Leonia	Line	PSEG	$1.1	$1.0	$2.3	$2.4	$0.7	$0.5	($0.2)	($0.0)	$2.4	948	52
Whitpain	Transformer	PECO	$5.2	$3.7	$0.3	$1.8	$8.0	$7.5	($0.1)	$0.4	$2.1	193	125
AP South	Interface	500	$13.8	$13.7	$0.8	$0.9	$24.6	$23.2	($0.3)	$1.2	$2.1	639	237
Wylie Ridge	Transformer	AP	$20.9	$19.2	$1.1	$2.7	$28.3	$28.6	($0.5)	($0.8)	$1.9	2,286	1,084
South Mahwah - Waldwick	Line	PSEG	$0.0	$0.0	$0.0	$0.0	$7.0	$7.1	($1.4)	($1.6)	($1.6)	0	37
Bedington - Black Oak	Interface	500	$93.8	$98.5	$5.4	$0.6	$98.1	$95.7	($1.6)	$0.8	$1.5	3,875	1,812
Unclassified	Unclassified	Unclassified	$1.7	$0.7	$0.5	$1.4	$0.0	$0.0	$0.0	$0.0	$1.4	NA	NA
Bayway - Doremus	Line	PSEG	$0.3	($0.9)	$0.2	$1.4	$0.0	$0.0	($0.0)	$0.0	$1.4	418	2

RECO Control Zone

Table 7-37 and Table 7-38 show the constraints with the largest impacts on total congestion cost in the RECO Control Zone. In 2007, the Branchburg — Readington and 5004/5005 interface constraints were the largest contributors to positive congestion while the South Mahwah — Waldwick and Brunner Island — Yorkana constraints contributed to negative congestion. In 2006, the Bedington — Black Oak and Cedar Grove — Roseland constraints had been the largest contributors to positive congestion. No constraints were significant contributors to negative congestion during 2006.

Table 7-37 RECO Control Zone top congestion cost impacts (By facility): Calendar year 2007

			Congestion Costs (Millions)									Event Hours	
			Day Ahead				Balancing						
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Branchburg - Readington	Line	PSEG	$2.9	$0.1	$0.2	$3.1	$4.1	$4.0	($0.3)	($0.2)	$2.9	2,324	721
5004/5005 Interface	Interface	500	$1.3	$0.1	$0.0	$1.2	$0.9	$0.8	($0.0)	$0.1	$1.3	1,512	386
Cedar Grove - Roseland	Line	PSEG	$1.1	$0.0	$0.0	$1.0	$0.4	$0.4	($0.0)	$0.1	$1.1	1,677	133
Cloverdale - Lexington	Line	AEP	$0.8	$0.1	$0.0	$0.8	$1.2	$1.1	($0.0)	$0.1	$0.9	3,704	1,885
Bedington - Black Oak	Interface	500	$1.0	$0.0	$0.0	$0.9	$0.4	$0.4	($0.1)	($0.1)	$0.9	5,493	1,836
South Mahwah - Waldwick	Line	PSEG	($0.1)	($0.0)	($0.0)	($0.2)	($0.8)	($0.1)	$0.0	($0.7)	($0.8)	304	58
Kammer	Transformer	500	$0.7	$0.0	$0.0	$0.7	$1.1	$1.0	($0.0)	$0.1	$0.8	2,005	947
Central	Interface	500	$0.7	$0.0	$0.0	$0.7	$0.0	$0.0	$0.0	$0.0	$0.7	1,334	25
Wylie Ridge	Transformer	AP	$0.6	$0.0	$0.0	$0.6	$0.7	$0.7	($0.0)	$0.0	$0.6	1,486	685
Atlantic - Larrabee	Line	JCPL	$0.3	$0.0	$0.0	$0.3	$0.5	$0.5	$0.0	$0.0	$0.3	680	134
West	Interface	500	$0.2	$0.0	$0.0	$0.2	$0.6	$0.6	($0.0)	$0.0	$0.3	359	338
AP South	Interface	500	$0.3	$0.1	$0.0	$0.2	$0.2	$0.1	($0.0)	$0.0	$0.2	706	133
East	Interface	500	$0.2	$0.0	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	304	5
Brunner Island - Yorkana	Line	Met-Ed	($0.2)	($0.0)	$0.0	($0.2)	($0.5)	($0.5)	$0.0	($0.0)	($0.2)	172	196
Branchburg - Flagtown	Line	PSEG	$0.2	$0.0	$0.0	$0.2	$0.3	$0.3	($0.0)	$0.0	$0.2	580	104

Table 7-38 RECO Control Zone top congestion cost impacts (By facility): Calendar year 2006

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Bedington - Black Oak	Interface	500	$2.3	$0.1	$0.2	$2.3	$2.6	$2.3	($0.2)	$0.1	$2.4	3,875	1,812
Cedar Grove - Roseland	Line	PSEG	$1.6	$0.0	$0.1	$1.7	$0.9	$0.9	($0.1)	($0.0)	$1.6	3,692	541
5004/5005 Interface	Interface	500	$1.6	$0.3	$0.0	$1.4	$1.1	$0.8	($0.1)	$0.2	$1.6	1,738	341
West	Interface	500	$0.7	$0.0	$0.1	$0.7	$0.6	$0.6	($0.0)	$0.0	$0.8	981	328
Kammer	Transformer	500	$0.6	$0.0	$0.0	$0.6	$0.6	$0.5	($0.1)	$0.0	$0.7	2,043	688
Mount Storm - Pruntytown	Line	AP	$0.5	$0.0	$0.1	$0.6	$0.4	$0.4	($0.1)	($0.0)	$0.5	891	465
AP South	Interface	500	$0.3	$0.0	$0.0	$0.4	$0.7	$0.5	($0.0)	$0.2	$0.5	639	237
Central	Interface	500	$0.5	$0.0	$0.0	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	699	15
Wylie Ridge	Transformer	AP	$0.5	$0.0	$0.0	$0.5	$0.8	$0.7	($0.1)	($0.0)	$0.5	2,286	1,084
Branchburg - Readington	Line	PSEG	$0.5	$0.0	$0.0	$0.5	$1.3	$1.3	($0.1)	($0.1)	$0.5	704	480
Kanawha - Matt Funk	Line	AEP	$0.4	$0.0	$0.0	$0.4	$0.4	$0.3	($0.0)	($0.0)	$0.4	2,025	617
Cloverdale - Lexington	Line	AEP	$0.3	$0.0	$0.0	$0.3	$0.8	$0.7	($0.1)	($0.0)	$0.3	1,517	961
Doubs - Mount Storm	Line	500	$0.3	$0.0	$0.0	$0.2	$0.2	$0.1	($0.0)	$0.0	$0.2	240	50
Aqueduct - Doubs	Line	AP	$0.1	$0.0	$0.0	$0.1	$0.1	$0.1	($0.0)	$0.0	$0.1	362	127
Axton	Transformer	AEP	$0.2	$0.0	$0.0	$0.1	$0.0	$0.0	($0.0)	($0.0)	$0.1	218	35

Western Region Congestion-Event Summaries

AEP Control Zone

Table 7-39 and Table 7-40 show the constraints with the largest impacts on total congestion cost in the AEP Control Zone. In 2007, the Bedington — Black Oak and Kammer transformer constraints were the largest contributors to positive congestion while the Cloverdale — Lexington and Darwin — Eugene constraints contributed to negative congestion. In 2006, the Bedington — Black Oak and Kanawha — Matt Funk constraints had been the largest contributors to positive congestion while the Cloverdale — Lexington constraint contributed to negative congestion.

Table 7-39 AEP Control Zone top congestion cost impacts (By facility): Calendar year 2007

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Bedington - Black Oak	Interface	500	($405.4)	($519.1)	$7.3	$120.9	($322.4)	($287.5)	($0.3)	($35.2)	$85.7	5,493	1,836
Kammer	Transformer	500	($131.9)	($168.1)	($0.2)	$36.0	($146.0)	($133.4)	$0.0	($12.6)	$23.4	2,005	947
Amos	Transformer	AEP	$14.1	($3.4)	$0.3	$17.8	$38.8	$38.3	($0.2)	$0.2	$18.0	311	132
5004/5005 Interface	Interface	500	($101.9)	($118.6)	$0.5	$17.3	($46.9)	($43.9)	($0.1)	($3.1)	$14.2	1,512	386
Cloverdale - Lexington	Line	AEP	($271.5)	($274.8)	($5.3)	($2.0)	($276.8)	($265.4)	$0.2	($11.2)	($13.1)	3,704	1,885
Axton	Transformer	AEP	($5.5)	($12.8)	$1.0	$8.3	$0.0	$0.0	$0.0	$0.0	$8.3	238	0
AP South	Interface	500	($62.9)	($73.6)	$0.3	$11.0	($44.9)	($40.8)	$0.0	($4.1)	$6.9	706	133
Wylie Ridge	Transformer	AP	($72.7)	($86.7)	$1.3	$15.3	($77.6)	($68.6)	($0.2)	($9.2)	$6.1	1,486	685
Central	Interface	500	($47.7)	($53.5)	$0.0	$5.8	($1.5)	($1.4)	$0.0	($0.0)	$5.8	1,334	25
Bedington	Transformer	AP	($33.2)	($40.4)	$0.4	$7.6	($30.3)	($28.2)	($0.0)	($2.1)	$5.5	928	429
Kanawha - Matt Funk	Line	AEP	($14.4)	($21.0)	$0.9	$7.5	($12.9)	($10.2)	($0.2)	($2.8)	$4.7	90	95
Axton - Jacksons Ferry	Line	AEP	($3.4)	($7.5)	$0.6	$4.8	($0.3)	($0.2)	($0.0)	($0.2)	$4.6	238	5
Kanawha River	Transformer	AEP	$1.0	($1.9)	$0.6	$3.5	$0.4	$0.4	$0.0	($0.0)	$3.5	63	12
Darwin - Eugene	Line	AEP	($0.0)	($3.0)	($0.1)	$2.9	$2.0	$8.0	($0.1)	($6.1)	($3.3)	109	227
Cloverdale	Transformer	AEP	($10.6)	($14.6)	$0.2	$4.2	($14.4)	($12.3)	($0.0)	($2.1)	$2.2	233	152

Table 7-40 AEP Control Zone top congestion cost impacts (By facility): Calendar year 2006

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Bedington - Black Oak	Interface	500	($107.1)	($170.9)	$6.1	$69.9	($77.5)	($64.7)	($0.1)	($12.9)	$57.0	3,875	1,812
Kanawha - Matt Funk	Line	AEP	($12.4)	($69.5)	$1.3	$58.4	($5.4)	$3.9	($2.2)	($11.5)	$46.9	2,025	617
Kammer	Transformer	500	($101.0)	($126.1)	$3.3	$28.4	($65.5)	($61.7)	$0.2	($3.6)	$24.7	2,043	688
Axton	Transformer	AEP	($1.3)	($18.6)	$2.7	$20.0	$0.1	$0.6	$0.0	($0.5)	$19.5	218	35
Mount Storm - Pruntytown	Line	AP	($17.0)	($33.7)	$1.7	$18.4	($8.4)	($6.5)	$0.1	($1.8)	$16.6	891	465
5004/5005 Interface	Interface	500	($106.1)	($119.1)	($0.5)	$12.5	($45.2)	($45.2)	$0.1	$0.1	$12.6	1,738	341
Axton - Jacksons Ferry	Line	AEP	($0.4)	($8.2)	$1.0	$8.8	$0.0	$0.1	$0.0	($0.1)	$8.7	380	10
Cedar Grove - Roseland	Line	PSEG	($104.8)	($111.6)	$1.9	$8.8	($48.4)	($47.7)	$0.0	($0.6)	$8.2	3,692	541
Wylie Ridge	Transformer	AP	($63.3)	($74.7)	$2.6	$14.1	($76.1)	($70.1)	($0.5)	($6.6)	$7.5	2,286	1,084
Cloverdale - Lexington	Line	AEP	($60.3)	($58.6)	($1.4)	($3.0)	($113.6)	($110.9)	$0.1	($2.6)	($5.7)	1,517	961
Central	Interface	500	($37.5)	($42.6)	($0.2)	$4.9	($1.1)	($1.1)	$0.0	$0.0	$4.9	699	15
AP South	Interface	500	($33.0)	($37.9)	$0.4	$5.3	($38.6)	($37.2)	$0.2	($1.2)	$4.2	639	237
Bedington	Transformer	AP	($14.5)	($18.4)	$0.3	$4.3	($3.6)	($3.0)	$0.0	($0.6)	$3.7	662	451
Breed - Wheatland	Line	AEP	($0.5)	($4.1)	$0.2	$3.8	$0.1	$0.2	($0.1)	($0.3)	$3.5	411	29
West	Interface	500	($59.4)	($64.0)	$1.3	$5.9	($42.5)	($40.1)	($0.0)	($2.5)	$3.4	981	328

AP Control Zone

Table 7-41 and Table 7-42 show the constraints with the largest impacts on total congestion cost in the AP Control Zone. In 2007, the Bedington — Black Oak and Cloverdale — Lexington constraints were the largest contributors to positive congestion while the Kammer and Wylie Ridge transformer constraints contributed to negative congestion. In 2006, the Bedington — Black Oak, Meadowbrook transformer and Mount Storm — Pruntytown constraints had been the largest contributors to positive congestion while the Kammer transformer and Aqueduct — Doubs constraints contributed to negative congestion.

Table 7-41 AP Control Zone top congestion cost impacts (By facility): Calendar year 2007

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Bedington - Black Oak	Interface	500	($33.0)	($290.3)	$4.3	$261.5	($16.3)	$8.3	$3.4	($21.3)	$240.2	5,493	1,836
Cloverdale - Lexington	Line	AEP	$27.6	($19.7)	$7.0	$54.3	$10.1	$13.3	($4.4)	($7.6)	$46.7	3,704	1,885
Meadow Brook	Transformer	AP	$33.5	$1.1	$0.6	$33.0	$8.6	$8.5	($0.2)	($0.1)	$32.9	868	233
Bedington	Transformer	AP	$21.3	($12.9)	($0.1)	$34.1	$9.4	$12.0	($0.5)	($3.1)	$31.0	928	429
AP South	Interface	500	$1.7	($23.0)	$0.6	$25.3	($0.2)	$1.5	$0.2	($1.6)	$23.7	706	133
Branchburg - Readington	Line	PSEG	($24.4)	($28.1)	$8.9	$12.6	($15.6)	($14.4)	$0.6	($0.6)	$12.0	2,324	721
5004/5005 Interface	Interface	500	($26.3)	($35.9)	$0.2	$9.7	($6.3)	($6.0)	$0.2	($0.1)	$9.6	1,512	386
Kammer	Transformer	500	$31.1	$43.5	$4.4	($8.0)	$13.7	$11.4	($3.8)	($1.5)	($9.5)	2,005	947
Elrama - Mitchell	Line	AP	$11.5	$3.9	$3.4	$11.0	$6.4	$7.8	($2.2)	($3.6)	$7.4	1,883	784
Bedington - Nipetown	Line	AP	$4.8	($2.9)	$0.2	$7.9	$1.8	$2.9	$0.1	($1.1)	$6.9	841	175
Wylie Ridge	Transformer	AP	$10.6	$14.0	$3.0	($0.4)	$4.3	$6.3	($3.6)	($5.5)	($5.9)	1,486	685
Doubs	Transformer	AP	$4.1	($1.5)	$0.1	$5.7	$2.7	$2.5	($0.2)	($0.0)	$5.7	135	99
Cedar Grove - Roseland	Line	PSEG	$1.4	($2.6)	$1.3	$5.3	($0.4)	($0.3)	$0.1	$0.1	$5.4	1,677	133
Central	Interface	500	($13.5)	($16.3)	$1.3	$4.1	($0.2)	($0.2)	$0.0	($0.0)	$4.1	1,334	25
Aqueduct - Doubs	Line	AP	($6.8)	($3.7)	($0.3)	($3.4)	($0.7)	($0.8)	$0.0	$0.1	($3.2)	262	21

Table 7-42 AP Control Zone top congestion cost impacts (By facility): Calendar year 2006

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Bedington - Black Oak	Interface	500	$28.4	($153.7)	($4.4)	$177.8	$6.6	$18.4	$2.3	($9.4)	$168.4	3,875	1,812
Meadow Brook	Transformer	AP	$42.4	$3.0	($0.6)	$38.9	$1.5	$1.1	$0.1	$0.5	$39.4	726	124
Mount Storm - Pruntytown	Line	AP	$5.2	($34.5)	($0.5)	$39.2	$1.1	$1.6	$0.6	$0.1	$39.4	891	465
Bedington	Transformer	AP	$27.6	($3.4)	($0.2)	$30.8	$5.3	$8.8	$0.5	($3.1)	$27.7	662	451
AP South	Interface	500	$7.0	($14.6)	($0.1)	$21.5	$2.7	$4.1	($0.2)	($1.6)	$19.9	639	237
Doubs	Transformer	AP	$10.3	($3.7)	($0.0)	$14.0	$1.4	$1.3	($0.0)	$0.2	$14.2	90	74
Kammer	Transformer	500	$30.7	$42.9	$0.2	($12.1)	$1.4	$2.1	($0.1)	($0.7)	($12.8)	2,043	688
Cloverdale - Lexington	Line	AEP	$11.0	($2.1)	$1.0	$14.1	$0.7	$4.2	($0.4)	($3.9)	$10.2	1,517	961
Aqueduct - Doubs	Line	AP	($15.3)	($5.7)	($0.2)	($9.8)	($1.2)	($1.2)	($0.0)	($0.0)	($9.8)	362	127
Kanawha - Matt Funk	Line	AEP	$12.3	$3.2	$0.6	$9.7	$0.6	$1.9	($0.1)	($1.4)	$8.3	2,025	617
Doubs - Mount Storm	Line	500	$2.4	($6.1)	($0.5)	$8.0	$0.2	$1.0	($0.2)	($1.0)	$7.0	240	50
Wylie Ridge	Transformer	AP	$12.4	$14.3	$1.3	($0.6)	($0.6)	$2.9	($2.8)	($6.3)	($6.9)	2,286	1,084
Cedar Grove - Roseland	Line	PSEG	($32.7)	($37.7)	$0.6	$5.6	($2.1)	($1.4)	$0.8	$0.2	$5.8	3,692	541
Branchburg - Readington	Line	PSEG	($11.2)	($11.9)	$0.4	$1.1	($3.8)	($0.9)	($1.7)	($4.7)	($3.5)	704	480
Fort Martin - Pruntytown	Line	500	$2.0	($1.4)	$0.1	$3.4	$0.0	$0.2	($0.0)	($0.3)	$3.2	111	22

ComEd Control Zone

Table 7-43 and Table 7-44 show the constraints with the largest impacts on total congestion cost in the ComEd Control Zone. In 2007, the Bedington — Black Oak and Cloverdale — Lexington constraints were the largest contributors to positive congestion while the South Mahwah — Waldwick constraint contributed to negative congestion. In 2006, the Kammer transformer and Cloverdale — Lexington constraints had been the largest contributors to positive congestion while the Northwest — Devon constraint contributed to negative congestion.

Table 7-43 ComEd Control Zone top congestion cost impacts (By facility): Calendar year 2007

			Congestion Costs (Millions)									Event Hours	
			Day Ahead				Balancing						
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Bedington - Black Oak	Interface	500	($463.0)	($490.0)	($0.6)	$26.5	($229.0)	($247.8)	$0.2	$19.1	$45.5	5,493	1,836
Cloverdale - Lexington	Line	AEP	($273.3)	($299.8)	($0.1)	$26.4	($158.3)	($175.5)	($0.1)	$17.2	$43.6	3,704	1,885
Kammer	Transformer	500	($167.1)	($178.7)	($0.1)	$11.5	($102.4)	($113.1)	($0.0)	$10.7	$22.2	2,005	947
Branchburg - Readington	Line	PSEG	($87.9)	($88.4)	$0.0	$0.5	($59.5)	($69.0)	$0.0	$9.5	$10.0	2,324	721
Wylie Ridge	Transformer	AP	($71.8)	($74.6)	($0.0)	$2.8	($43.9)	($50.3)	$0.0	$6.5	$9.2	1,486	685
5004/5005 Interface	Interface	500	($110.9)	($116.1)	($0.0)	$5.2	($31.7)	($33.9)	$0.0	$2.2	$7.5	1,512	386
AP South	Interface	500	($67.6)	($70.2)	($0.0)	$2.5	($27.3)	($29.2)	$0.0	$1.9	$4.4	706	133
Central	Interface	500	($51.9)	($54.9)	$0.0	$3.0	($0.9)	($0.9)	($0.0)	$0.0	$3.0	1,334	25
West	Interface	500	($18.9)	($19.1)	($0.0)	$0.1	($28.8)	($31.1)	$0.0	$2.3	$2.5	359	338
Kanawha - Matt Funk	Line	AEP	($20.3)	($22.1)	($0.0)	$1.8	($13.3)	($13.9)	$0.0	$0.6	$2.3	90	95
Cloverdale	Transformer	AEP	($15.2)	($16.9)	($0.0)	$1.7	($14.8)	($15.2)	$0.0	$0.5	$2.2	233	152
Elrama - Mitchell	Line	AP	($19.5)	($21.0)	($0.0)	$1.6	($17.1)	($17.6)	$0.0	$0.5	$2.1	1,883	784
State Line - Wolf Lake	Flowgate	Midwest ISO	($21.4)	($24.2)	($0.1)	$2.7	($27.5)	($26.9)	$0.0	($0.6)	$2.1	1,241	590
Dresden	Transformer	ComEd	$2.7	$0.4	$0.0	$2.3	$2.9	$3.4	($0.0)	($0.5)	$1.8	77	22
South Mahwah - Waldwick	Line	PSEG	$5.9	$6.0	$0.0	($0.1)	$10.6	$12.1	($0.0)	($1.5)	($1.6)	304	58

Table 7-44 ComEd Control Zone top congestion cost impacts (By facility): Calendar year 2006

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Kammer	Transformer	500	($146.6)	($148.2)	$4.2	$5.8	($10.1)	($19.9)	($0.2)	$9.6	$15.4	2,043	688
Cloverdale - Lexington	Line	AEP	($70.0)	($74.8)	$1.7	$6.5	($18.9)	($25.9)	($0.0)	$7.0	$13.5	1,517	961
Wylie Ridge	Transformer	AP	($75.1)	($76.7)	$2.5	$4.2	($9.1)	($17.5)	$0.2	$8.6	$12.8	2,286	1,084
Bedington - Black Oak	Interface	500	($164.4)	($164.7)	$3.6	$3.9	($16.3)	($24.8)	($0.0)	$8.5	$12.4	3,875	1,812
Cedar Grove - Roseland	Line	PSEG	($136.0)	($139.2)	$3.7	$6.9	($9.7)	($12.2)	($0.0)	$2.4	$9.3	3,692	541
Branchburg - Readington	Line	PSEG	($46.8)	($46.8)	$0.7	$0.7	($12.2)	($19.0)	($0.0)	$6.8	$7.5	704	480
Kanawha - Matt Funk	Line	AEP	($53.0)	($52.8)	$1.8	$1.6	($4.0)	($9.7)	($0.2)	$5.5	$7.2	2,025	617
Cherry Valley - Belvidere	Line	ComEd	$5.3	($1.0)	$0.0	$6.4	$0.8	$0.9	$0.0	($0.2)	$6.2	39	12
5004/5005 Interface	Interface	500	($144.3)	($145.5)	$3.4	$4.6	($10.7)	($11.4)	($0.0)	$0.8	$5.4	1,738	341
Jefferson - Taylor	Line	ComEd	$23.9	$19.1	($0.2)	$4.6	$1.3	$0.7	$0.0	$0.6	$5.2	137	11
Dresden	Transformer	ComEd	$9.3	$4.5	($0.0)	$4.7	$0.9	$0.5	$0.0	$0.3	$5.1	64	18
West	Interface	500	($78.5)	($78.1)	$1.4	$0.9	($5.1)	($9.1)	($0.0)	$4.0	$4.9	981	328
Oak Park - Ridgeland	Line	ComEd	$12.9	$8.7	($0.0)	$4.1	$0.0	$0.0	$0.0	$0.0	$4.1	338	0
AP South	Interface	500	($42.1)	($42.5)	$1.2	$1.6	($7.4)	($9.5)	($0.0)	$2.1	$3.7	639	237
Northwest - Devon	Line	ComEd	($0.0)	($0.2)	$0.0	$0.2	($5.0)	($1.6)	($0.1)	($3.4)	($3.2)	17	52

DAY Control Zone

Table 7-45 and Table 7-46 show the constraints with the largest impacts on total congestion cost in the DAY Control Zone. In 2007, the Cloverdale — Lexington and Kammer transformer constraints were the largest contributors to positive congestion while the Amos transformer constraint contributed to negative congestion. In 2006, the Kammer transformer and Cedar Grove — Roseland constraints had been the largest contributors to positive congestion while the Avon transformer contributed to negative congestion.

Table 7-45 DAY Control Zone top congestion cost impacts (By facility): Calendar year 2007

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Cloverdale - Lexington	Line	AEP	($29.3)	($35.2)	$0.1	$6.0	($30.5)	($30.5)	($0.0)	($0.1)	$6.0	3,704	1,885
Kammer	Transformer	500	($18.8)	($21.6)	($0.0)	$2.8	($20.9)	($19.8)	($0.0)	($1.1)	$1.7	2,005	947
Bedington - Black Oak	Interface	500	($56.8)	($60.3)	($0.1)	$3.3	($48.5)	($46.2)	($0.0)	($2.3)	$1.0	5,493	1,836
Central	Interface	500	($5.7)	($6.6)	$0.0	$0.9	($0.2)	($0.2)	$0.0	($0.0)	$0.9	1,334	25
5004/5005 Interface	Interface	500	($13.0)	($14.3)	($0.0)	$1.3	($6.2)	($5.8)	($0.0)	($0.4)	$0.9	1,512	386
Branchburg - Readington	Line	PSEG	($9.8)	($10.8)	$0.0	$1.0	($13.1)	($12.4)	($0.0)	($0.7)	$0.3	2,324	721
Axton	Transformer	AEP	($1.5)	($1.8)	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	238	0
Wylie Ridge	Transformer	AP	($8.7)	($9.1)	($0.0)	$0.3	($9.7)	($9.5)	$0.0	($0.1)	$0.2	1,486	685
East	Interface	500	($1.5)	($1.7)	$0.0	$0.2	($0.0)	($0.0)	$0.0	($0.0)	$0.2	304	5
AP South	Interface	500	($8.1)	($8.6)	($0.0)	$0.5	($5.8)	($5.4)	($0.0)	($0.3)	$0.2	706	133
Eureka - Willow Island	Line	AP	($0.1)	($0.3)	$0.0	$0.2	($0.1)	($0.1)	($0.0)	($0.0)	$0.2	239	34
Cloverdale	Transformer	AEP	($1.6)	($2.0)	$0.0	$0.4	($2.7)	($2.5)	($0.0)	($0.2)	$0.2	233	152
South Mahwah - Waldwick	Line	PSEG	$0.7	$0.8	($0.0)	($0.1)	$2.4	$2.2	($0.0)	$0.2	$0.1	304	58
Amos	Transformer	AEP	($0.4)	($0.3)	($0.0)	($0.2)	($1.1)	($1.1)	$0.0	$0.0	($0.1)	311	132
Homer City - Shelocta	Line	PENELEC	$0.2	$0.2	($0.0)	$0.0	$0.6	$0.4	$0.0	$0.1	$0.1	200	99

Table 7-46 DAY Control Zone top congestion cost impacts (By facility): Calendar year 2006

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Kammer	Transformer	500	($14.4)	($17.9)	($0.3)	$3.2	($10.2)	($9.6)	$0.0	($0.6)	$2.5	2,043	688
Cedar Grove - Roseland	Line	PSEG	($12.5)	($14.8)	$0.1	$2.5	($6.3)	($6.1)	($0.0)	($0.3)	$2.2	3,692	541
Cloverdale - Lexington	Line	AEP	($6.3)	($7.8)	$0.6	$2.1	($12.9)	($12.8)	($0.0)	($0.0)	$2.1	1,517	961
5004/5005 Interface	Interface	500	($13.7)	($14.7)	$1.5	$2.5	($6.5)	($6.1)	$0.0	($0.5)	$2.0	1,738	341
Avon	Transformer	AEP	$0.0	$0.0	$0.0	$0.0	($0.6)	$0.8	($0.0)	($1.4)	($1.4)	0	229
Kanawha - Matt Funk	Line	AEP	($8.2)	($10.1)	($0.1)	$1.8	($7.5)	($6.8)	($0.0)	($0.7)	$1.0	2,025	617
West	Interface	500	($7.4)	($8.9)	($0.2)	$1.4	($5.5)	($5.0)	($0.0)	($0.5)	$0.9	981	328
Marquis - Killen	Line	AEP	($0.2)	($0.8)	$0.3	$0.9	$0.0	$0.0	$0.0	$0.0	$0.9	288	0
Central	Interface	500	($4.7)	($5.0)	$0.5	$0.8	($0.2)	($0.1)	$0.0	($0.0)	$0.8	699	15
Meadow Brook	Transformer	AP	($2.6)	($2.5)	$0.6	$0.4	($0.3)	($0.2)	$0.0	($0.0)	$0.4	726	124
Doubs - Mount Storm	Line	500	($2.7)	($2.7)	$0.4	$0.4	($1.4)	($1.4)	$0.0	$0.0	$0.4	240	50
Cloverdale	Transformer	AEP	($1.1)	($1.3)	$0.1	$0.3	($0.5)	($0.5)	($0.0)	$0.0	$0.3	221	34
East	Interface	500	($1.2)	($1.5)	($0.0)	$0.3	($0.1)	($0.1)	$0.0	($0.0)	$0.3	324	11
AP South	Interface	500	($4.2)	($4.8)	($0.1)	$0.5	($5.6)	($5.3)	$0.0	($0.2)	$0.3	639	237
Axton	Transformer	AEP	($2.7)	($2.8)	$0.1	$0.3	($0.4)	($0.4)	($0.0)	($0.1)	$0.3	218	35

DLCO Control Zone

Table 7-47 and Table 7-48 show the constraints with the largest impacts on total congestion cost in the DLCO Control Zone. In 2007, the Bedington — Black Oak and Beaver — Clinton constraints were the largest contributors to positive congestion while the Elrama — Mitchell and Sammis — Wylie Ridge constraints contributed to negative congestion. In 2006, the Bedington — Black Oak and Cedar Grove — Roseland constraints had been the largest contributors to positive congestion while the Sammis — Wylie Ridge and Elrama — Mitchell constraints contributed to negative congestion.

Table 7-47 DLCO Control Zone top congestion cost impacts (By facility): Calendar year 2007

			Congestion Costs (Millions)									Event Hours	
			Day Ahead				Balancing						
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Bedington - Black Oak	Interface	500	($134.5)	($157.7)	($0.1)	$23.2	($70.4)	($58.1)	$0.0	($12.3)	$10.9	5,493	1,836
Beaver - Clinton	Line	DLCO	($0.1)	($6.9)	$0.1	$6.8	$2.5	$2.0	$0.0	$0.5	$7.3	451	43
Elrama - Mitchell	Line	AP	($27.2)	($27.9)	($0.1)	$0.6	($32.7)	($25.9)	$0.1	($6.7)	($6.2)	1,883	784
Carson - Homested	Line	DLCO	$3.4	($1.2)	$0.0	$4.7	$0.0	$0.0	$0.0	($0.0)	$4.6	253	2
Cloverdale - Lexington	Line	AEP	($19.3)	($25.8)	$0.0	$6.6	($12.3)	($10.3)	($0.0)	($2.0)	$4.5	3,704	1,885
Wylie Ridge	Transformer	AP	($29.8)	($38.4)	($0.0)	$8.6	($21.9)	($17.5)	$0.0	($4.4)	$4.2	1,486	685
5004/5005 Interface	Interface	500	($26.8)	($31.7)	($0.0)	$4.9	($8.0)	($6.6)	$0.0	($1.4)	$3.5	1,512	386
Branchburg - Readington	Line	PSEG	($15.0)	($18.3)	($0.0)	$3.3	($11.5)	($10.5)	$0.0	($1.0)	$2.3	2,324	721
Sammis - Wylie Ridge	Line	AP	($1.3)	($2.0)	$0.0	$0.7	($9.1)	($6.2)	$0.0	($2.9)	($2.2)	90	109
Central	Interface	500	($9.3)	($11.4)	($0.0)	$2.1	($0.2)	($0.2)	$0.0	($0.0)	$2.1	1,334	25
Cheswick - Evergreen	Line	DLCO	($0.8)	($3.1)	$0.0	$2.3	$0.0	$0.2	$0.0	($0.2)	$2.1	300	102
Brunot Island - Montour	Line	DLCO	$2.1	($0.1)	$0.0	$2.2	$3.1	$3.4	($0.0)	($0.3)	$1.9	88	42
Crescent - Neville Tap	Line	DLCO	$0.9	($0.8)	$0.0	$1.7	$1.0	$0.9	($0.0)	$0.1	$1.8	100	44
Kammer	Transformer	500	($4.6)	($6.9)	$0.0	$2.3	($3.7)	($3.2)	($0.0)	($0.6)	$1.7	2,005	947
Unclassified	Unclassified	Unclassified	$1.6	$0.1	$0.0	$1.5	$0.0	$0.0	$0.0	$0.0	$1.5	NA	NA

Table 7-48 DLCO Control Zone top congestion cost impacts (By facility): Calendar year 2006

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Bedington - Black Oak	Interface	500	($56.7)	($65.4)	$1.6	$10.3	($33.4)	($28.2)	$0.1	($5.1)	$5.2	3,875	1,812
Cedar Grove - Roseland	Line	PSEG	($17.1)	($21.2)	$1.0	$5.0	($6.0)	($5.2)	$0.0	($0.9)	$4.1	3,692	541
Wylie Ridge	Transformer	AP	($22.9)	($29.1)	$2.2	$8.4	($23.9)	($18.9)	$0.0	($4.9)	$3.4	2,286	1,084
5004/5005 Interface	Interface	500	($25.3)	($28.5)	$0.3	$3.5	($8.0)	($7.5)	$0.0	($0.5)	$3.1	1,738	341
West	Interface	500	($12.0)	($15.1)	$0.3	$3.4	($6.0)	($5.1)	$0.0	($0.9)	$2.5	981	328
Mount Storm - Pruntytown	Line	AP	($12.9)	($15.2)	$0.2	$2.5	($6.5)	($5.8)	$0.0	($0.7)	$1.8	891	465
Kammer	Transformer	500	($3.6)	($5.1)	$0.3	$1.8	($1.4)	($1.1)	($0.0)	($0.3)	$1.5	2,043	688
Sammis - Wylie Ridge	Line	AP	$0.0	$0.0	$0.0	$0.0	($5.2)	($3.9)	$0.0	($1.3)	($1.3)	0	125
Cheswick - Evergreen	Line	DLCO	($0.1)	($1.3)	$0.0	$1.2	$0.1	$0.1	$0.0	($0.0)	$1.2	167	45
Crescent	Transformer	DLCO	$0.0	$0.0	$0.0	$0.0	$7.8	$6.8	($0.0)	$0.9	$0.9	0	23
Central	Interface	500	($7.1)	($8.0)	$0.1	$0.9	($0.1)	($0.1)	$0.0	($0.0)	$0.9	699	15
Elrama	Transformer	AP	($0.9)	($1.8)	$0.0	$0.9	($0.0)	($0.0)	$0.0	($0.0)	$0.9	927	34
Kanawha - Matt Funk	Line	AEP	($3.1)	($4.0)	$0.3	$1.2	($2.2)	($1.8)	($0.0)	($0.4)	$0.9	2,025	617
Elrama - Mitchell	Line	AP	($5.4)	($6.0)	$0.5	$1.2	($7.9)	($6.0)	$0.0	($1.9)	($0.8)	654	258
Branchburg - Readington	Line	PSEG	($5.9)	($7.3)	$0.2	$1.7	($8.7)	($7.7)	$0.0	($1.0)	$0.7	704	480

Southern Region Congestion-Event Summaries

Dominion Control Zone

Table 7-49 and Table 7-50 show the constraints with the largest impacts on total congestion cost in the Dominion Control Zone. In 2007, the Bedington — Black Oak and Cloverdale — Lexington constraints were the largest contributors to positive congestion while the Branchburg — Readington and Central interface constraints contributed to negative congestion. In 2006, the Bedington — Black Oak and AP South interface constraints had been the largest contributors to positive congestion while the Cedar Grove — Roseland constraint contributed to negative congestion.

Table 7-49 Dominion Control Zone top congestion cost impacts (By facility): Calendar year 2007

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Bedington - Black Oak	Interface	500	$587.7	$503.2	$11.1	$95.6	$567.3	$556.0	($8.0)	$3.4	$99.0	5,493	1,836
Cloverdale - Lexington	Line	AEP	$242.7	$160.3	$10.9	$93.3	$346.0	$345.6	($7.3)	($6.8)	$86.4	3,704	1,885
AP South	Interface	500	$43.6	$8.7	$0.4	$35.2	$31.7	$29.7	$0.4	$2.3	$37.5	706	133
Meadow Brook	Transformer	AP	($6.7)	($16.0)	($0.2)	$9.0	($1.1)	($1.2)	$0.0	$0.2	$9.2	868	233
Kammer	Transformer	500	$45.7	$40.4	$1.6	$6.8	$58.3	$56.9	($1.2)	$0.3	$7.1	2,005	947
Bedington	Transformer	AP	$22.7	$16.9	$0.5	$6.3	$24.3	$23.3	($0.4)	$0.6	$6.9	928	429
Branchburg - Readington	Line	PSEG	($70.1)	($63.8)	($0.3)	($6.5)	($83.5)	($82.8)	$0.6	($0.0)	($6.6)	2,324	721
5004/5005 Interface	Interface	500	($16.6)	($21.7)	$0.4	$5.4	($9.6)	($9.4)	$0.2	$0.1	$5.5	1,512	386
Central	Interface	500	($32.5)	($28.3)	($0.2)	($4.4)	($1.0)	($1.0)	$0.0	($0.0)	($4.4)	1,334	25
Cloverdale	Transformer	AEP	$11.2	$7.7	$0.4	$3.9	$20.4	$19.6	($0.4)	$0.4	$4.3	233	152
Wylie Ridge	Transformer	AP	$16.3	$12.9	$0.8	$4.3	$19.8	$19.6	($0.3)	($0.1)	$4.2	1,486	685
Halifax - Clover	Line	Dominion	($2.3)	($6.4)	($0.0)	$4.0	$0.0	$0.0	$0.0	$0.0	$4.0	130	5
Ox	Transformer	Dominion	$2.1	($2.0)	($0.0)	$4.1	$5.7	$5.8	$0.0	($0.1)	$4.0	39	43
Aqueduct - Doubs	Line	AP	$5.0	$1.7	$0.1	$3.4	$2.0	$1.9	($0.0)	$0.1	$3.5	262	21
Doubs	Transformer	AP	$2.3	($1.1)	($0.0)	$3.3	($0.0)	$0.0	$0.0	$0.0	$3.3	135	99

Table 7-50 Dominion Control Zone top congestion cost impacts (By facility): Calendar year 2006

			Congestion Costs (Millions)										
			Day Ahead				Balancing					Event Hours	
Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Bedington - Black Oak	Interface	500	$545.2	$481.7	$7.0	$70.4	$511.9	$515.5	($2.4)	($6.0)	$64.5	3,875	1,812
AP South	Interface	500	$46.3	$18.4	$0.1	$28.0	$79.6	$77.5	($0.6)	$1.6	$29.5	639	237
Cloverdale - Lexington	Line	AEP	$70.8	$37.5	$1.9	$35.3	$188.3	$191.1	($5.0)	($7.8)	$27.5	1,517	961
Doubs - Mount Storm	Line	500	$17.3	$2.2	$0.1	$15.2	$11.4	$11.5	($0.3)	($0.4)	$14.8	240	50
Cedar Grove - Roseland	Line	PSEG	($74.2)	($63.1)	($0.4)	($11.5)	($39.8)	($38.3)	($0.0)	($1.5)	($13.0)	3,692	541
Meadow Brook	Transformer	AP	($9.3)	($23.1)	($0.7)	$13.2	$0.5	$0.8	$0.1	($0.2)	$13.0	726	124
Kanawha - Matt Funk	Line	AEP	$105.7	$87.2	$1.0	$19.5	$100.1	$108.3	($1.7)	($9.8)	$9.7	2,025	617
Aqueduct - Doubs	Line	AP	$17.9	$9.1	$0.4	$9.2	$13.7	$13.1	($0.2)	$0.5	$9.7	362	127
Dooms	Transformer	Dominion	$17.0	$7.9	$0.7	$9.9	$46.3	$44.9	($2.0)	($0.6)	$9.3	150	147
Doubs	Transformer	AP	$1.0	($5.8)	$0.0	$6.8	$1.5	$1.4	$0.1	$0.1	$6.9	90	74
5004/5005 Interface	Interface	500	($22.7)	($27.3)	$0.0	$4.5	($10.0)	($10.9)	($0.0)	$0.9	$5.4	1,738	341
Kammer	Transformer	500	$46.8	$39.3	$0.6	$8.1	$30.6	$33.0	($0.4)	($2.9)	$5.2	2,043	688
Mount Storm - Pruntytown	Line	AP	$141.4	$136.4	$1.5	$6.5	$118.3	$118.5	($1.2)	($1.4)	$5.1	891	465
Cloverdale	Transformer	AEP	$12.6	$7.3	$0.2	$5.6	$6.5	$6.9	($0.1)	($0.5)	$5.0	221	34
Dayton - Harrisonburg	Line	Dominion	$5.6	$1.2	$0.2	$4.6	$0.0	$0.0	$0.0	$0.0	$4.6	74	0

Economic Planning Process

Transmission system investments can be evaluated on a reliability basis or on an economic basis. The reliability evaluation examines whether a transmission upgrade is required in order to maintain reliability on the system in a particular area or areas, using specific planning and reliability criteria.[15] The economic evaluation examines whether a transmission upgrade, including reliability upgrades, results in positive economic benefits. The economic evaluation is more complex because there is more judgment involved in the choice of relevant metrics for both benefits and costs. PJM's responsibility as an RTO requires PJM to constantly evaluate the need for transmission investments related to reliability and to help ensure that the responsible transmission owner constructs needed facilities. As the operator and designer of markets, PJM also needs to consider the appropriate role for the economic evaluation of transmission system investments.

15 See PJM. "Amended And Restated Operating Agreement of PJM Interconnection, L.L.C." (December 7, 2007) (Accessed February 27, 2008), Schedule 6 < http://www.pjm.com/documents/downloads/agreements/oa.pdf > (1,123 KB).

Investments in transmission are currently compensated under the FERC's traditional rate base – rate of return regulatory approach. While PJM's Tariff permits merchant projects, the significant merchant transmission projects have been direct current (DC) tie lines to export power rather than investments in network facilities. As a general matter, transmission investments have not been fully incorporated into competitive markets. The construction of new transmission facilities can have significant impacts on energy markets, but there is no market mechanism in place that would permit competition between transmission and generation to meet loads in an area. While it does not address the issue of permitting competition between transmission and generation projects, the first step toward integrating transmission investments into the market has been the use of economic evaluation metrics to determine whether there are positive economic benefits associated with an investment in transmission that might warrant the investment even when it was not required for reliability.

PJM has made multiple filings related to economic metrics for evaluating transmission investments.[16] The FERC has required that PJM use an approach with predefined formulas for determining whether a defined transmission investment passes the cost-benefit test including explicit accounting for changes in production costs, the costs of complying with environmental regulations, generation availability trends and demand-response trends.[17]

On October 9, 2007, PJM submitted its compliance filing to address these issues and to provide a formulaic approach for including transmission projects in the RTEP.[18]

Under PJM's proposed approach, PJM would perform market simulations with and without the proposed transmission investments including reliability-based investments and economic investments. The result would be used to determine the economic benefits of the investments and whether to include such investment in the RTEP. An economic investment would be included in the RTEP, if the relative benefits and costs of the investment meet a benefit/cost ratio (Equation 7-1) threshold of at least 1.25:1:[19]

Equation 7-1 Proposed benefit/cost ratio

benefit / cost ratio =
[total annual enhancement benefit] ÷ [total enhancement cost] .

The benefit component of the benefit/cost ratio is the total annual enhancement benefit which is the sum of two metrics: the *Energy Market benefit* and the *Reliability Pricing Model* benefit. The Energy Market benefit and the Reliability Pricing Model benefit are defined in Equation 7-2 and Equation 7-3, respectively:

Equation 7-2 Energy Market benefit

Energy Market benefit =
[0.70] • [change in total energy production cost] + [0.30] • [change in load energy payment]; and

16 *PJM Interconnection, L.L.C.*, PJM Interconnection, L.L.C. submitted modifications to its Regional Transmission Expansion Planning Protocol, Docket No. ER06-1474-000 (September 8, 2006). PJM Interconnection, L.L.C. submitted its compliance filing providing additional information and amendments to its Regional Transmission Expansion Planning Protocol, Docket No. ER06-1474-003 (March 21, 2007).

17 119 FERC ¶ 61,265 (2007).

18 PJM Interconnection, L.L.C. submitted its compliance filing, Docket No. ER06-1474-000 (October 9, 2007). As of December 31, 2007, the FERC had not issued an order in response to this October compliance filing.

19 The enhancement benefits and costs appearing in Equation 7-1 are determined as the present value of the annual total for each of the first 15 years of the life of the enhancement or expansion.

Equation 7-3 Reliability Pricing Model benefit

Reliability Pricing Model benefit =
[0.70] • [change in total system capacity cost] + [0.30] • [change in load capacity payment].

The Energy Market benefit measures benefits as the weighted sum of changes in energy production cost and load energy payment.[20, 21] The Reliability Pricing Model benefit measures benefits as the weighted sum of changes in total system capacity cost and in load capacity payment.[22, 23] The change in production costs is the total resource saving associated with a transmission investment. The change in load payments for energy is a direct measure of the net load savings associated with the investment.

The cost component of the benefit/cost ratio (total enhancement cost) in Equation 7-1 is expressed in Equation 7-4 as the present value of the revenue requirement of the transmission investment:

Equation 7-4 Total enhancement cost

total enhancement cost =
the estimated annual revenue requirement for the economic-based enhancement or expansion.

PJM's RTEP is a planning process that integrates transmission, generation and demand-side resources to address transmission system constraints that affect reliability and system economics.[24]

The proposed revisions to the economic planning process incorporate improvements over the existing process but require continued development. The most significant improvements are the inclusion of less discretionary metrics and the evaluation of demand-side response and generation resources as alternatives to transmission investment. New transmission projects, and the lack of existing transmission, can have significant impacts on PJM markets. The goal of transmission planning should ultimately be the incorporation of transmission investment decisions into market-driven processes as much as is practicable.

20 The change in total energy production cost = the difference in the following between the case with the investment and without the investment: [the estimated total annual fuel costs, variable O&M costs, and emissions costs of the dispatched resources].

21 The change in load energy payment = the difference in the following between the case with the investment and without the investment: [annual sum of (hourly estimated zonal load MW for each zone) • (hourly estimated zonal LMP for each zone)] – [annual sum of (hourly estimated zonal load MW for each zone) • (hourly estimated zonal LMP for each zone)]. For economic-based enhancements and expansions for which cost responsibility is assigned pursuant to section (b)(i) of Schedule 12 of the PJM Tariff, the change in the load energy payment is determined as the sum of the change in load energy payment in all zones. For economic-based enhancements or expansions for which cost responsibility is assigned pursuant to section (b)(v) of Schedule 12 of the PJM Tariff, the change in load energy payment is determined as the sum of the change in the load energy payment only of the zones that show a decrease in load energy payment.

22 The change in total system capacity cost = the difference in the following between the case with the investment and without the investment: [the sum of (the MW that are estimated to be cleared in the base residual auction under Attachment DD of the PJM Tariff) • (the prices that are estimated to be contained in the sell offers for each such cleared MW) • (the number of days in the study year)].

23 The change in load capacity payment = the difference in the following between the case with the investment and without the investment: [the sum of (the estimated zonal load MW in each zone) • (the estimated final zonal Capacity Market prices under Attachment DD of the PJM Tariff) • (the number of days in the study year)]. For economic-based enhancements and expansions for which cost responsibility is assigned pursuant to section (b)(i) of Schedule 12 of the PJM Tariff, the change in the load capacity payment is determined as the sum of the change in load capacity payment in all zones. For economic-based enhancements or expansions for which cost responsibility is assigned pursuant to section (b)(v) of Schedule 12 of the PJM Tariff, the change in load Capacity Market payment is determined as the sum of the change in the load Capacity Market payment only of the zones that show a decrease in load Capacity Market payment.

24 See "Regional Transmission Expansion Plan Executive Summary" (February 27, 2007) (Accessed January 24, 2008) < http://www2.pjm.com/planning/downloads/20070301-section-01.pdf> (3MB).

SECTION 8 – FINANCIAL TRANSMISSION AND AUCTION REVENUE RIGHTS

Financial Transmission Rights (FTRs) and Auction Revenue Rights (ARRs) give transmission service customers and PJM members an offset against congestion costs in the Day-Ahead Energy Market. An FTR provides the holder with revenues, or charges, equal to the difference in congestion prices in the Day-Ahead Energy Market across the specific FTR transmission path. An ARR is a related product that provides the holder with 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 transmission service 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 network service and long-term, firm, point-to-point transmission service customers as a hedge against congestion costs since the inception of locational marginal pricing (LMP) on April 1, 1998. Effective June 1, 2003, PJM replaced the allocation of FTRs with an allocation of ARRs and an associated Annual FTR Auction.[1] Since the introduction of this auction, FTRs have been available to all transmission service customers and PJM members. Network service and firm point-to-point transmission service customers can take allocated ARRs or the underlying FTRs through a self-scheduling process. On June 1, 2007, PJM implemented marginal losses in the calculation of LMP. Since then, FTRs have been valued based on the difference in congestion prices rather than the difference in LMPs.

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

The *2007 State of the Market Report* focuses on two FTR/ARR planning periods: the 2006 to 2007 planning period which covers June 1, 2006, through May 31, 2007, and the 2007 to 2008 planning period which covers June 1, 2007, through May 31, 2008.

Overview

Financial Transmission Rights (FTRs)

Market Structure

- Supply. PJM operates an Annual FTR Auction for all control zones in the PJM footprint. PJM conducts 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. PJM also administers a secondary bilateral market to allow participants to buy and sell existing FTRs. FTR products include FTR obligations and FTR options. Each of these is available for 24-hour, on-peak and off-peak periods. FTRs have

1 87 FERC ¶ 61,054 (1999).

terms varying from one month to one year. 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 binding constraints limiting the supply of FTRs in the Annual FTR Auction for the 2007 to 2008 planning period include the Bedington — Black Oak Interface and the Meadowbrook transformer.[2] Market participants can also sell FTRs. For the 2007 to 2008 planning period, total FTR sell offers were 117,199 MW, up from 76,669 MW during the 2006 to 2007 planning period. In the Monthly Balance of Planning Period FTR Auctions for the first seven months (June through December 2007) of the 2007 to 2008 planning period, there were 1,912,181 MW of FTR sell offers.

- Demand. There is no limit on FTR demand in any FTR auction. In the Annual FTR Auction for the 2007 to 2008 planning period, total FTR buy bids were 2,223,687 MW, up from 1,570,121 MW during the 2006 to 2007 planning period. Total FTR self-scheduled bids were 71,360 MW for the 2007 to 2008 planning period, an increase from 38,301 MW for the 2006 to 2007 planning period. In the Monthly Balance of Planning Period FTR Auctions for the first seven months (June through December 2007) of the 2007 to 2008 planning period, total FTR buy bids were 8,427,824 MW.

- FTR Credit Issues. Two participants defaulted on their FTR-related payment obligations in 2007 as the result of inadequate collateral held by PJM to cover the participants' losses resulting from counterflow FTR positions. The defaults made it clear that PJM credit polices related to FTRs and particularly to counterflow FTRs were inadequate. On December 21, 2007, PJM submitted to the United States Federal Energy Regulatory Commission (FERC) revisions to its Open Access Transmission Tariff (OATT) to improve the credit requirements for FTR market participants.[3] PJM submitted an additional filing on January 31, 2008, to the FERC to increase the credit requirement for market participants with net counterflow FTR positions.[4] The defaults also raised potential market gaming issues, which were addressed, in part, in a PJM filing.[5] These are being investigated.

- Patterns of Ownership. 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. 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. In order to evaluate the ownership of prevailing flow and counterflow FTRs, the MMU categorized all participants owning FTRs in PJM as either physical or financial. Physical entities include utilities and customers which primarily take physical positions in PJM markets. Financial entities include banks and hedge funds which primarily take financial positions in PJM markets. Physical entities own slightly more than half of prevailing flow FTRs while financial entities own about three quarters of counterflow FTRs. Overall, the ownership of all FTRs is about evenly split between physical and financial entities.

2 During calendar years 2004 and 2005, PJM conducted the phased integration of five control zones. Four of these, American Electric Power (AEP), The Dayton Power & Light Company (DAY), Duquesne Light Company (DLCO) and Dominion, were eligible for direct allocation FTRs during the 2006 to 2007 planning period, but not the 2007 to 2008 planning period. For additional information on the integrations, their timing and their impact on the footprint of the PJM service territory, see the *2007 State of the Market Report*, Volume II, Appendix A, "PJM Geography."

3 *PJM Interconnection, L.L.C.*, PJM Interconnection, L.L.C. submits revisions to the PJM Credit Policy Attachment Q, Docket No. ER08-376-000 (December 26, 2007).

4 *PJM Interconnection, L.L.C.*, PJM Interconnection, L.L.C. submits revisions to the Credit Policy Attachment Q of their Open-Access Transmission Tariff, FERC Electric Tariff, Sixth Revised Volume 1, to become effective April 1, 2008, Docket No. ER08-520-000 (January 31, 2008).

5 PJM Interconnection, L.L.C. made a filing under section 205 of the Federal Power Act to amend section 15.2 of the PJM Operating Agreement concerning defaults on short FTR portfolios in Docket No. ER08-455-000, (January 18, 2008).

Market Performance

- **Volume.** For the 2007 to 2008 planning period, the Annual FTR Auction cleared 208,637 MW (9.4 percent) of FTR buy bids, up from 129,866 MW (8.3 percent of demand) for the 2006 to 2007 planning period. The Annual FTR Auction also cleared 6,495 MW (5.5 percent) of FTR sell offers for the 2007 to 2008 planning period, down from 10,056 MW (13.1 percent) for the 2006 to 2007 planning period. For the first seven months of the 2007 to 2008 planning period, the Monthly Balance of Planning Period FTR Auctions cleared 610,829 MW (7.2 percent) of FTR buy bids and 155,606 MW (8.1 percent) of FTR sell offers. There were no direct allocation FTRs for the 2007 to 2008 planning period.

- **Price.** For the 2007 to 2008 planning period, 85 percent of the annual FTRs were purchased for less than $1 per MWh and 90.9 percent for less than $2 per MWh. For the 2007 to 2008 planning period, the weighted-average prices paid for annual buy-bid FTR obligations were $0.35 per MWh for 24-hour FTRs, $0.57 per MWh for on-peak FTRs and $0.47 per MWh for off-peak FTRs. Comparable, weighted-average prices for the 2006 to 2007 planning period were $1.95 per MWh for 24-hour and $0.78 per MWh for both on-peak and off-peak FTRs. The weighted-average prices paid for 2007 to 2008 planning period annual buy-bid FTR obligations and options were $0.47 per MWh and $0.37 per MWh, respectively, compared to $1.12 per MWh and $0.29 per MWh, respectively, in the 2006 to 2007 planning period.[6] The weighted-average price paid in the Monthly Balance of Planning Period FTR Auctions for the first seven months of the 2007 to 2008 planning period was $0.18 per MWh, compared with $0.22 per MWh in the Monthly Balance of Planning Period FTR Auctions for the full 12-month 2006 to 2007 planning period.

- **Revenue.** The Annual FTR Auction generated $1,698.03 million of net revenue for all FTRs during the 2007 to 2008 planning period, up from $1,417.5 million for the 2006 to 2007 planning period. The Monthly Balance of Planning Period FTR Auctions generated $28.2 million in net revenue for all FTRs during the first seven months of the 2007 to 2008 planning period.

- **Revenue Adequacy.** FTRs were 100 percent revenue adequate for the 2006 to 2007 planning period. FTRs were paid at 100 percent of the target allocation level for the first seven months of the 2007 to 2008 planning period. Congestion revenues are allocated to FTR holders based on FTR target allocations. PJM collected $1,532.7 million of FTR revenues during the first seven months of the 2007 to 2008 planning period and $1,906.1 million during the 2006 to 2007 planning period. For the first seven months of the 2007 to 2008 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 Atlantic, respectively.

6 Weighted-average prices for FTRs in the Annual FTR Auction and Monthly Balance of Planning Period FTR Auctions 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. For example, FTRs in the Annual FTR Auction would be weighted by their MW and the hours in that time period for each FTR class type: 24-hour (8,760 hours), on peak (4,080 hours) and off peak (4,680 hours).

Auction Revenue Rights (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 feasible ARRs. The principal binding constraints that limited supply in the annual ARR allocation for the 2007 to 2008 planning period were the Bedington — Black Oak and AP South interfaces. A new ARR product was added for the 2007 to 2008 planning period. Long-term ARRs are in effect for 10 consecutive planning periods and are available in Stage 1A of the annual ARR allocation. Residual ARRs were also introduced and are available to holders with prorated Stage 1A or 1B ARRs if additional transmission capability is added during the planning period.

- Demand. Total demand in the annual ARR allocation was 150,822 MW for the 2007 to 2008 planning period with 62,220 MW bid in Stage 1A, 31,063 MW bid in Stage 1B and 57,539 MW bid in Stage 2. This is up from 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. ARR demand is limited by the total amount of network service and firm point-to-point transmission service.

- ARR Reassignment for Retail Load Switching. When retail load switches among load-serving entities (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 control zone is allocated a proportional share of positively valued ARRs within the control zone based on the shifted load. There were 10,054 MW of ARRs associated with $326,800 per MW-day of revenue that were reassigned in the first seven months of the 2007 to 2008 planning period.

Market Performance

- Volume. Of 150,822 MW in ARR requests for the 2007 to 2008 planning period, 107,992 MW (71.6 percent) were allocated. There were 62,211 MW allocated in Stage 1A, 29,444 MW allocated in Stage 1B and 16,337 MW allocated in Stage 2. Eligible market participants self-scheduled 71,360 MW (66.1 percent) of these allocated ARRs as annual FTRs. Demand for ARRs increased because of load growth and the requirement that the AEP, DAY, DLCO and Dominion control zones take ARR allocations, instead of direct allocation FTRs. 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.

- 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 2007 to 2008 planning period, ARR holders will receive $1,640 million in ARR credits, with an average hourly ARR credit of $1.73 per MWh. During the 2007 to 2008 planning period, the ARR target allocations were $1,640 million while PJM collected $1,726 million from the combined Annual and Monthly Balance of Planning Period FTR Auctions through December 31, 2007, making ARRs revenue adequate. During the 2006 to 2007 planning period, ARR holders received $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 $1,435 million from the combined Annual and Monthly Balance of Planning Period FTR Auctions, making ARRs revenue adequate.

- ARR Proration. When ARRs were allocated for the 2007 to 2008 planning period, some of the requested ARRs were prorated as a result of binding transmission constraints. For the 2007 to 2008 planning period, no ARRs were prorated in Stage 1A of the annual ARR allocation. In Stage 1B, the only constraint affecting the ARR allocation was the Cedar Grove — Clifton line. There were 1,159.3 MW of Stage 1B ARRs denied to participants whose requested ARRs affected that binding transmission constraint.

- 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 Energy Market and the balancing energy market within PJM. During the 2006 to 2007 planning period, total ARR and FTR revenues hedged 98.4 percent of the congestion costs within PJM. For the first seven months of the 2007 to 2008 planning period, all ARRs and FTRs hedged 92.3 percent of the congestion costs within PJM.

Conclusion

The annual ARR allocation and the Annual FTR Auction together provide long-term, firm transmission service 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 results for the 2007 to 2008 planning period 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 ARRs do.

ARRs were 100 percent revenue adequate for both the 2007 to 2008 and the 2006 to 2007 planning periods. FTRs were paid at 100 percent of the target allocation level for the 12-month period of the 2006 to 2007 planning period, and at 100 percent of the target allocation level for the first seven months of the 2007 to 2008 planning period. The total of ARR and FTR revenues hedged 98.4 percent of the congestion costs in the Day-Ahead Energy Market and the balancing energy market within PJM for the 2006 to 2007 planning period and 92.3 percent of the congestion costs in PJM in the first seven months of the 2007 to 2008 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.

PJM faced substantial participant defaults in 2007 as a result of participant counterflow positions in the FTR markets in combination with inadequate PJM credit requirements and inadequate participant financial resources. PJM has taken steps to address the credit issue. The defaults also raised potential market gaming issues, which were addresed, in part, in a PJM filing. These are being investigated.

Financial Transmission Rights

While FTRs have been available to eligible participants since the 1998 introduction of LMP, the Annual FTR Auction was first implemented for the 2003 to 2004 planning period. For the 2006 to 2007 and the 2007 to 2008 planning periods, the auction covered all control zones. For the 2006 to 2007 planning period, eligible participants in the AEP, DAY, DLCO and Dominion control zones could select direct allocation FTRs or ARRs. For the 2007 to 2008 planning period, direct allocation FTRs were unavailable.

FTRs are financial instruments that entitle their holders to receive revenue or require them to pay charges based on locational congestion price differences in the Day-Ahead Energy Market across specific FTR transmission paths. Effective June 1, 2007, PJM added marginal losses as a component in the calculation of LMP.[7] The value of an FTR reflects the difference in congestion prices rather than the difference in LMPs, which includes both congestion and marginal losses. Auction market participants are free to request FTRs between any pricing nodes on the system, including hubs, control zones, aggregates, generator buses, load buses and interface pricing points. FTRs are available to the nearest 0.1 MW. The FTR target allocation is calculated hourly and is equal to the product of the FTR MW and the congestion price difference between sink and source that occurs in the Day-Ahead Energy Market. The value of an FTR can be positive or negative depending on the sink-minus-source congestion price difference, with a negative difference resulting in a liability for the holder. The FTR target allocation represents what the holders should receive if sufficient revenues are collected to fund FTRs.

Depending on the amount of FTR revenues collected, FTR holders with a positively valued FTR may receive congestion credits between zero and their target allocations. FTR holders with a negatively valued FTR are required to pay charges equal to their target allocations. When FTR holders receive their target allocations, the associated FTRs are fully funded. The objective function of all FTR auctions is to maximize the bid-based value of FTRs awarded in each auction.

FTRs can be bought, sold and self-scheduled. Buy bids are FTRs that are bought in the auctions; sell offers are existing FTRs that are sold in the auctions; and self-scheduled bids are FTRs that have been directly converted from ARRs.

7 For additional information on marginal losses, see the *2007 State of the Market Report*, Volume II, Section 2, “Energy Market, Part 1,” at “Real-Time Annual LMP Loss Component.”

There are two FTR hedge type products: obligations and options. An obligation provides a credit, positive or negative, equal to the product of the FTR MW and the congestion price difference between FTR sink (destination) and source (origin) that occurs in the Day-Ahead Energy Market. An option provides only positive credits and options are available for only a subset of the possible FTR transmission paths.

There are three FTR class type products: 24-hour, on peak and off peak. The 24-hour products are effective 24 hours a day, seven days a week, while the on-peak products are effective during on-peak periods defined as the hours ending 0800 through 2300, Eastern Prevailing Time (EPT) Mondays through Fridays, excluding North American Electric Reliability Council (NERC) holidays. The off-peak products are effective during hours ending 2400 through 0700, EPT, Mondays through Fridays, and during all hours on Saturdays, Sundays and NERC holidays.

FTR buy bids and sell offers may be made as obligations or options and as any of the three class types. FTR self-scheduled bids are available only as obligations and 24-hour class types, consistent with the associated ARRs.

Market Structure

Prior to implementation of the Annual FTR Auction, only network service and long-term, firm, point-to-point transmission service customers were able to directly obtain annual FTRs. Now all transmission service customers and PJM members can participate in the Annual FTR Auction as well as the Monthly Balance of Planning Period FTR Auctions.

Supply

The principal mechanism for obtaining FTRs is the Annual FTR Auction, including the ability to directly convert allocated ARRs into self-scheduled FTRs. A second mechanism for obtaining FTRs is the Monthly Balance of Planning Period FTR Auctions. Total FTR supply is limited by the capability of the transmission system to simultaneously accommodate the set of requested FTRs and the numerous combinations of FTRs that are feasible. For the Annual FTR Auction, transmission outages that are expected to last for two months or more are included, while outages of five days or more are included for the Monthly Balance of Planning Period FTR Auctions as well as any outages of a shorter duration that PJM determines would cause FTR revenue inadequacy if not modeled. FTRs can be traded between market participants through bilateral transactions. FTRs can also be obtained as direct allocation FTRs that are available to customers in recently integrated control zones.

During the 2007 to 2008 planning period, binding transmission constraints prevented the award of all requested FTRs in the Annual FTR Auction and Monthly Balance of Planning Period FTR Auctions.[8] Table 8-1 lists the top 10 binding constraints in the Annual FTR Auction along with their corresponding control zones. They are listed in order of severity, irrespective of auction round. For each of the top 10 binding constraints, a numerical ranking in order of severity for each auction round is also listed. The order of severity is determined by the marginal value of the binding constraint. The marginal value is computed and generated in the optimization engine.[9] It is the amount of value to be gained by relieving a constraint by 1 MW.

8 Binding constraints for Monthly Balance of Planning Period Auctions are posted to the PJM Web site in monthly files at http://www.pjm.com/markets/ftr/historical-ftr-auction.jsp.

9 PJM. “Manual 6: Financial Transmission Rights,” Revision 10 (June 1, 2007), p. 51.

Table 8-1 Top 10 principal binding transmission constraints limiting the Annual FTR Auction: Planning period 2007 to 2008[10]

			Severity Ranking by Auction Round			
Constraint	Type	Control Zone	1	2	3	4
Bedington - Black Oak	Interface	AP	1	1	1	1
Meadowbrook	Transformer	AP	4	2	2	3
Deepwater - Quinton	Line	AECO	2	3	3	2
Double Toll Gate - Old Chapel	Line	AP	6	4	4	4
Doubs	Transformer	AP	3	6	17	23
Waverly - Sargents	Line	AEP	5	8	6	8
Bedington - Nipetown	Line	AP	18	5	5	5
Branchburg - Readington	Line	PSEG	11	7	8	7
Bedington	Transformer	AP	NA	12	7	6
Mahans Lane - Tidd	Line	AEP	7	20	25	25

Annual FTR Auction

Each April, PJM conducts an Annual FTR Auction during which all eligible market participants can bid on FTRs for the next planning period consistent with total transmission system capability. The auction takes place over four rounds with 25 percent of the total transmission system capability awarded in each round:

- Round 1. Market participants make offers for FTRs between any source and sink. These offers can be 24-hour, on-peak or off-peak FTR obligations or FTR options. Locational prices are determined by maximizing the net revenue based on offer-based value of FTRs.[11] Any transmission service customer or PJM member can bid for available FTRs. ARR holders wishing to directly convert their previously allocated ARRs into self-scheduled FTRs must initiate that process in this round. One-quarter of each self-scheduled FTR clears as a 24-hour FTR in each of the four rounds. Self-scheduled FTRs must have the same source and sink as the corresponding ARR. Self-scheduled FTRs clear as price-taking FTR bids that are not eligible to set auction price.

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

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

10 The Bedington transformer was not constrained during the first auction round and is listed as NA (not applicable).

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

Monthly Balance of Planning Period FTR Auctions

Introduced at the beginning of the 2006 to 2007 planning period, the Monthly Balance of Planning Period FTR Auctions make available the residual FTR capability on the PJM transmission system after the Annual FTR Auction is concluded. They are single-round monthly auctions that allow any transmission service customers or PJM members to bid for any FTR or to offer for sale any FTR that they currently hold. Market participants can bid for or offer monthly FTRs for any of the next three months remaining in the planning period, or quarterly FTRs for any of the quarters remaining in the balance of the planning period. FTRs in the auctions can be either obligations or options and can be 24-hour, on-peak or off-peak products.[12]

Under the auction rules, market participants may bid to buy or offer to sell FTRs that have the following two terms. The first term is for one month for any of the next three months remaining in the planning period. For example, if the auction is conducted in May, any FTR valid for the months of June, July and August is included in the auction. The second term is for three months for any of the quarters remaining in the planning period (if technically feasible within the specified market time frame). For example, for planning period quarter 1 (Q1), the auction period would be June, July and August. For planning period quarter 2 (Q2), the auction period would be September, October and November. Similarly, December, January and February would be for planning period quarter 3 (Q3) and March, April and May would be for planning period quarter 4 (Q4). For example, an auction held in May would have all four quarters available, while an auction held in June would include quarter 2, quarter 3 and quarter 4, but not quarter 1. Quarter 1 would be excluded because the auction would be held midway through the first month of quarter 1 (June) and the quarters are auctioned in three-month periods only.

Secondary Bilateral Market

Market participants can buy and sell existing FTRs through the PJM-administered, bilateral market, or market participants can trade FTRs among themselves without PJM involvement. Bilateral transactions that are not done through PJM can involve parties that are not PJM members. PJM has no knowledge of bilateral transactions that are done outside of PJM's secondary bilateral market system.

For bilateral trades done through PJM, the FTR transmission path must remain the same; FTR obligations must remain obligations and FTR options must remain options. However, an individual FTR may be split up into multiple, smaller FTRs, down to increments of 0.1 MW. FTRs can also be given different start and end times, but the start time cannot be earlier than the original FTR start time and the end time cannot be later than the original FTR end time.

Direct Allocation FTRs

Direct allocation FTRs can be obtained when a new control zone is integrated into PJM. After their integration date, market participants in the new control zone have two planning periods during which they are eligible for a transitional allocation of FTRs or ARRs. After that transition, those market participants are subject to the ARR allocation rules and become ineligible for directly allocated FTRs. Like other market participants, they can still receive FTRs by self-scheduling their allocated ARRs.

12 PJM. "Manual 6: Financial Transmission Rights," Revision 10 (June 1, 2007), pp. 34-35.

Demand

Under current rules, participants may submit unlimited bids for FTRs for any single auction round in the Annual FTR Auction or for any single Monthly Balance of Planning Period FTR Auction.

FTR Credit Issues

Default

Two participants defaulted on their FTR-related payment obligations in 2007 as the result of inadequate collateral held by PJM to cover the participants' losses resulting from counterflow FTR positions. In October, Exel Power Sources, L.L.C. defaulted on September obligations and subsequently defaulted on additional 2007 obligations with a value of approximately $5 million. In December, Power Edge, L.L.C. defaulted on November obligations and subsequently defaulted on additional 2007 obligations with a value of approximately $21 million. Del Light, Inc. and PJS Capital, L.L.C. also defaulted in January 2008 on 2007 activity with values of approximately $0.4 million and $1 million.[13]

The defaults made it clear that PJM credit polices related to FTRs and particularly to counterflow FTRs were inadequate. The defaults also raised potential market gaming issues, which were addressed, in part, in a PJM filing.[14] These are being investigated.

Prevailing flow FTRs hedge congestion on a path. Participants purchase prevailing flow FTRs for a positive price with the expectation that the FTR revenues will exceed the cost of the FTRs. Counterflow FTRs expose the owner to paying congestion on a path. Participants receive a payment to take counterflow FTRs with the expectation that the payment will exceed the FTR charges. The risk of a prevailing flow FTR is generally limited to the purchase price, although risk could increase if congestion reversed. The risk of a counterflow FTR derives from the underlying congestion and is, therefore, not limited to a fixed payment. The risk is substantially greater for a counterflow FTR than for a prevailing flow FTR.

FTR Credit Rules

Under credit rules in place during 2007, PJM required participants in FTR auctions to meet defined credit requirements linked to the value of the FTRs. PJM calculates the FTR credit requirement for each market participant using FTR cost and a measure of the historical congestion on the FTR path for the planning period, discounted by 30 percent. The 30 percent adjustment does not apply to counterflow FTRs. PJM calculates a total FTR credit requirement for each market participant, which must be maintained to participate in the FTR auctions.[15]

On December 21, 2007, PJM submitted to the FERC revisions to its OATT to improve the credit requirements for FTR market participants.[16] The revisions would change the calculation period for the FTR credit requirement to a monthly from an annual basis and would also calculate and allocate offsets for ARR credits

13 Additional information on the defaults is available on the PJM Web Site at http://www.pjm.com/services/membership/default-notification.html.

14 PJM Interconnection, L.L.C. made a filing under section 205 of the Federal Power Act to amend section 15.2 of the PJM Operating Agreement concerning defaults on short FTR portfolios in Docket No. ER08-455-000, (January 18, 2008).

15 For the complete FTR Auction credit business rules, see PJM. "Manual 6: Financial Transmission Rights," Revision 10 (June 1, 2007), pp.38-41.

16 *PJM Interconnection, L.L.C.*, PJM Interconnection, L.L.C. submits revisions to the PJM Credit Policy Attachment Q, Docket No. ER08-376-000 (December 26, 2007).

monthly rather than annually. The credit calculation would sum only the months with positive net credit requirements and would apply a generic 10 percent adjustment to historical values of both prevailing flow FTRs and counterflow FTRs to account for likely differences from historical experience.

PJM submitted an additional filing on January 31, 2008, to the FERC to increase the credit requirement for market participants with net counterflow FTR positions.[17] Participants with net counterflow positions have potential liabilities that are not naturally limited in the way that the liabilities of prevailing flow FTRs are limited. Participants are paid to take counterflow positions in return for making a stream of payments based on actual congestion. The credit requirements for net counterflow positions would be multiplied by two and if the counterflow position is not well diversified geographically, would be multiplied by three.

Patterns of Ownership

The overall ownership structure of FTRs and the ownership of prevailing flow and counterflow FTRs are evaluated.

The ownership concentration of cleared FTR buy bids resulting from the 2007 to 2008 Annual FTR Auction was low for FTR obligations and high for FTR options. This ownership information is only descriptive and is not a measure of actual or potential FTR market structure issues, as the ownership positions result from competitive auctions. The percentage of FTR ownership shares may change when FTR owners buy or sell FTRs in the Monthly Balance of Planning Period FTR Auctions or secondary bilateral market.

For cleared FTR buy-bid obligations, the HHIs were 728 for 24-hour, 724 for on-peak and 771 for off-peak FTR products while maximum market shares were 20 percent for 24-hour, 15 percent for on-peak and 12 percent for off-peak FTR products.

For cleared FTR buy-bid options, HHIs were 2508 for 24-hour, 3185 for on-peak and 3928 for off-peak products while maximum market shares were 44 percent for 24-hour, 52 percent for on-peak and 60 percent for off-peak FTR products.

In order to evaluate the ownership of prevailing flow and counterflow FTRs, the MMU categorized all participants owning FTRs in PJM as either physical or financial. Physical entities include utilities and customers which primarily take physical positions in PJM markets. Financial entities include banks and hedge funds which primarily take financial positions in PJM markets. The MMU used available public information to categorize FTR owners and while the distinctions are not perfect, they are accurate enough to support some general conclusions. Table 8-2 presents the Annual FTR Auction market concentration for cleared FTRs in the 2007 to 2008 planning period by organization type and FTR direction. The results show that physical entities own slightly more than half of prevailing flow FTRs while financial entities own about three quarters of counterflow FTRs. Overall, the ownership of all FTRs is about evenly split between physical and financial entities.

17 *PJM Interconnection, L.L.C.*, PJM Interconnection, L.L.C. submits revisions to the Credit Policy Attachment Q of their Open-Access Transmission Tariff, FERC Electric Tariff, Sixth Revised Volume 1, to become effective April 1, 2008, Docket No. ER08-520-000 (January 31, 2008).

Table 8-2 Annual FTR Auction patterns of ownership by FTR direction: Planning period 2007 to 2008

	FTR Direction		
Organization Type	Prevailing Flow	Counterflow	All
Physical	57.2%	25.8%	48.9%
Financial	42.8%	74.2%	51.1%
Total	100.0%	100.0%	100.0%

Market Performance

Volume

Table 8-3 shows the Annual FTR Auction volume by trade type and auction round for the 2007 to 2008 planning period. The total volume was 2,223,687 MW for FTR buy bids and 117,199 MW for FTR sell offers for the 2007 to 2008 planning period. This is up from the total volume of 1,570,121 MW for FTR buy bids and 76,669 MW for FTR sell offers for the 2006 to 2007 planning period.

There were 208,637 MW (9.4 percent) of cleared FTR buy bids and 6,495 MW (5.5 percent) of cleared FTR sell offers for the 2007 to 2008 planning period. This is an increase from the total of 129,866 MW (8.3 percent) of cleared FTR buy bids and a decrease from 10,056 MW (13.1 percent) of cleared FTR sell offers for the 2006 to 2007 planning period.

Direct allocation FTRs were unavailable for the 2007 to 2008 planning period. For the 2006 to 2007 planning period, the total demand for direct allocation FTRs in the AEP, DAY, DLCO and Dominion control zones was 43,796 MW. There were 39,901 MW (91.1 percent) cleared, leaving 3,895 MW (8.9 percent) of uncleared direct allocation FTR requests.

Table 8-3 Annual FTR Auction market volume: Planning period 2007 to 2008

Trade Type	Auction Round	Bid and Requested Count	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Uncleared Volume (MW)	Uncleared Volume
Buy bids	1	90,733	629,439	53,093	8.4%	576,346	91.6%
	2	91,778	656,406	60,460	9.2%	595,946	90.8%
	3	64,061	456,119	46,873	10.3%	409,246	89.7%
	4	62,949	481,723	48,211	10.0%	433,512	90.0%
	Total	309,521	2,223,687	208,637	9.4%	2,015,050	90.6%
Self-scheduled bids	1	2,672	17,840	17,840	100.0%	0	0.0%
	2	2,672	17,840	17,840	100.0%	0	0.0%
	3	2,672	17,840	17,840	100.0%	0	0.0%
	4	2,672	17,840	17,840	100.0%	0	0.0%
	Total	10,688	71,360	71,360	100.0%	0	0.0%
Buy and self-scheduled bids	1	93,405	647,279	70,933	11.0%	576,346	89.0%
	2	94,450	674,246	78,300	11.6%	595,946	88.4%
	3	66,733	473,959	64,713	13.7%	409,246	86.3%
	4	65,621	499,563	66,051	13.2%	433,512	86.8%
	Total	320,209	2,295,047	279,997	12.2%	2,015,050	87.8%
Sell offers	1	NA	NA	NA	NA	NA	NA
	2	4,535	18,771	1,489	7.9%	17,282	92.1%
	3	7,531	40,507	2,441	6.0%	38,066	94.0%
	4	9,434	57,921	2,565	4.4%	55,356	95.6%
	Total	21,500	117,199	6,495	5.5%	110,704	94.5%

Table 8-4 shows that for the 2007 to 2008 planning period, eligible market participants converted 71,360 MW of ARRs out of a possible 107,992 MW into annual FTRs. In comparison, during the 2006 to 2007 planning period, eligible market participants converted 38,301 MW of ARRs out of a possible 67,568 MW.

Table 8-4 Comparison of self-scheduled FTRs: Planning periods 2006 to 2007 and 2007 to 2008

Planning Period	Self-Scheduled FTRs (MW)	Maximum Possible Self-Scheduled FTRs (MW)	Percent of ARRs Self-Scheduled as FTRs
2006/2007	38,301	67,568	56.7%
2007/2008	71,360	107,992	66.1%

Table 8-5 shows that there were 8,427,824 MW of FTR buy bids and 1,912,181 MW of FTR sell offers for all bidding periods in the Monthly Balance of Planning Period FTR Auctions for the 2007 to 2008 planning period through December 31, 2007. The monthly auctions cleared 610,829 MW (7.2 percent) leaving 7,816,995 MW (92.8 percent) of uncleared FTR buy bids. There were 155,606 MW (8.1 percent) of cleared FTR sell offers leaving 1,756,575 MW (91.9 percent) of uncleared FTR sell offers.

The Monthly Balance of Planning Period FTR Auctions for the full 12-month 2006 to 2007 planning period had a total demand of 10,037,353 MW for FTR buy bids and 1,760,060 MW for FTR sell offers. The monthly auctions cleared 703,677 MW (7.0 percent) of FTR buy bids and 167,933 MW (9.5 percent) of FTR sell offers.

Table 8-5 Monthly Balance of Planning Period FTR Auction market volume: January 2007 to December 2007

Monthly Auction	Trade Type	Bid and Requested Count	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Uncleared Volume (MW)	Uncleared Volume
Jan-07	Buy bids	156,611	905,249	71,628	7.9%	833,621	92.1%
	Sell offers	21,907	126,983	11,814	9.3%	115,169	90.7%
Feb-07	Buy bids	157,762	969,447	77,368	8.0%	892,079	92.0%
	Sell offers	17,279	84,494	9,189	10.9%	75,305	89.1%
Mar-07	Buy bids	152,490	799,130	83,507	10.4%	715,623	89.6%
	Sell offers	25,781	137,192	13,753	10.0%	123,439	90.0%
Apr-07	Buy bids	112,934	551,601	44,709	8.1%	506,892	91.9%
	Sell offers	18,290	96,190	13,745	14.3%	82,445	85.7%
May-07	Buy bids	105,382	480,219	46,318	9.6%	433,901	90.4%
	Sell offers	8,932	47,435	9,112	19.2%	38,323	80.8%
Jun-07	Buy bids	252,773	1,166,967	85,311	7.3%	1,081,656	92.7%
	Sell offers	58,669	383,062	35,182	9.2%	347,880	90.8%
Jul-07	Buy bids	191,960	1,068,961	80,213	7.5%	988,748	92.5%
	Sell offers	46,499	274,471	28,965	10.6%	245,506	89.4%
Aug-07	Buy bids	220,050	1,224,668	84,443	6.9%	1,140,225	93.1%
	Sell offers	52,581	280,653	21,051	7.5%	259,602	92.5%
Sep-07	Buy bids	210,234	1,200,731	91,277	7.6%	1,109,454	92.4%
	Sell offers	57,428	299,447	24,666	8.2%	274,781	91.8%
Oct-07	Buy bids	210,926	1,245,798	129,154	10.4%	1,116,644	89.6%
	Sell offers	54,458	271,862	16,727	6.2%	255,135	93.8%
Nov-07	Buy bids	180,285	1,059,631	76,970	7.3%	982,661	92.7%
	Sell offers	46,644	218,305	15,379	7.0%	202,926	93.0%
Dec-07	Buy bids	190,280	1,461,068	63,461	4.3%	1,397,607	95.7%
	Sell offers	39,124	184,381	13,636	7.4%	170,745	92.6%

Table 8-6 shows the bid and cleared volume for FTR buy bids in the Monthly Balance of Planning Period FTR Auctions by bidding period for January 2007 through December 2007.

Table 8-6 Monthly Balance of Planning Period FTR Auction buy-bid bid and cleared volume (MW per period): January 2007 to December 2007

Monthly Auction	MW Type	Current Month	Second Month	Third Month	Q1	Q2	Q3	Q4	Total
Jan-07	Bid	514,491	137,697	109,648				143,413	905,249
	Cleared	52,665	8,645	3,361				6,957	71,628
Feb-07	Bid	606,601	112,492	105,954				144,400	969,447
	Cleared	64,447	4,593	3,631				4,697	77,368
Mar-07	Bid	468,987	142,103	127,507				60,533	799,130
	Cleared	61,858	10,124	8,027				3,498	83,507
Apr-07	Bid	420,473	131,128						551,601
	Cleared	37,065	7,644						44,709
May-07	Bid	480,219							480,219
	Cleared	46,318							46,318
Jun-07	Bid	338,863	175,226	165,400	87,827	134,530	137,928	127,193	1,166,967
	Cleared	36,433	11,334	12,018	4,287	7,465	7,495	6,279	85,311
Jul-07	Bid	405,059	199,897	102,256		124,838	121,543	115,368	1,068,961
	Cleared	41,262	12,572	5,896		7,623	7,147	5,713	80,213
Aug-07	Bid	498,752	106,516	98,361		169,487	179,761	171,791	1,224,668
	Cleared	43,904	6,429	6,098		8,157	10,019	9,836	84,443
Sep-07	Bid	546,318	102,371	101,203		110,568	175,115	165,156	1,200,731
	Cleared	48,276	9,642	9,115		6,004	9,705	8,535	91,277
Oct-07	Bid	561,623	186,446	103,784			202,661	191,284	1,245,798
	Cleared	94,036	11,334	6,220			8,598	8,966	129,154
Nov-07	Bid	470,466	108,359	103,673			194,265	182,868	1,059,631
	Cleared	49,571	7,578	6,000			7,812	6,009	76,970
Dec-07	Bid	512,716	281,129	275,932			262,947	128,344	1,461,068
	Cleared	38,795	7,144	5,997			3,151	8,374	63,461

Table 8-7 shows the secondary bilateral FTR market volume by hedge type and class type for the 2006 to 2007 and the 2007 to 2008 planning periods. There were 2,122 MW of total bilateral FTR activity for the 2007 to 2008 planning period while there were 6,032 MW during the 2006 to 2007 planning period. There were no option FTRs traded through the PJM secondary bilateral FTR market for the 2006 to 2007 planning period.

Table 8-7 Secondary bilateral FTR market volume: Planning periods 2006 to 2007 and 2007 to 2008[18]

Planning Period	Hedge Type	Class Type	Secondary (MW)
2006/2007	Obligation	24-hour	4,225
		On peak	958
		Off peak	849
		Total	6,032
2007/2008	Obligation	24-hour	57
		On peak	1,239
		Off peak	216
		Total	1,512
	Option	24-hour	0
		On peak	446
		Off peak	164
		Total	610

Price

Table 8-8 shows the weighted-average bid price by trade type in the Annual FTR Auction and the Monthly Balance of Planning Period FTR Auctions for the 2007 to 2008 planning period.

Table 8-8 Annual and Monthly Balance of Planning Period FTR Auction weighted-average bid prices (Dollars per MWh): Planning period 2007 to 2008

	Trade Type	Average Bid Price
Annual FTR Auction	Buy bids	($0.53)
	Self-scheduled bids	NA
	Sell offers	$0.72
Monthly Balance of Planning Period FTR Auctions*	Buy bids	($0.58)
	Sell offers	$1.19

* Shows seven months ended 31-Dec-07

Table 8-9 shows the cleared, weighted-average prices by trade type, hedge type, auction round and class type for annual FTRs during the 2007 to 2008 planning period. For the 2007 to 2008 planning period, weighted-average, buy-bid FTR obligation prices were $0.47 per MWh while weighted-average, buy-bid FTR option prices were $0.37 per MWh. Comparable weighted-average prices for the 2006 to 2007 planning period were $1.12 per MWh for buy-bid FTR obligations and $0.29 per MWh for buy-bid FTR options.

18 The 2007 to 2008 planning period covers the 2007 to 2008 Annual FTR Auction and the Monthly Balance of Planning Period FTR Auctions through December 31, 2007.

For the 2007 to 2008 planning period, weighted-average sell offer FTR obligation prices were $0.07 per MWh while weighted-average sell offer FTR option prices were -$0.94 per MWh. Comparable weighted-average prices for the 2006 to 2007 planning period were -$0.86 per MWh for sell offer FTR obligations and -$0.15 per MWh for sell offer FTR options.

On average during the 2007 to 2008 planning period in the Annual FTR Auction, self-scheduled FTRs were priced $1.47 per MWh higher than buy-bid obligation FTRs. They were also priced $0.83 per MWh lower than the cleared, weighted-average price of self-scheduled FTRs during the 2006 to 2007 planning period.

Table 8-9 Annual FTR Auction weighted-average cleared prices (Dollars per MWh): Planning period 2007 to 2008

			Class Type			
Trade Type	Hedge Type	Auction Round	24-Hour	On Peak	Off Peak	All
Buy bids	Obligations	1	$0.09	$0.69	$0.61	$0.47
		2	$0.52	$0.36	$0.26	$0.39
		3	$0.44	$0.56	$0.53	$0.51
		4	$0.32	$0.70	$0.56	$0.54
		Total	$0.35	$0.57	$0.47	$0.47
	Options	1	$0.15	$0.75	$0.18	$0.45
		2	$0.22	$0.53	$0.30	$0.37
		3	$0.44	$0.72	$0.19	$0.42
		4	$0.05	$0.49	$0.19	$0.28
		Total	$0.23	$0.61	$0.21	$0.37
Self-scheduled bids	Obligations	1	$1.93	NA	NA	$1.93
		2	$1.96	NA	NA	$1.96
		3	$1.95	NA	NA	$1.95
		4	$1.93	NA	NA	$1.93
		Total	$1.94	NA	NA	$1.94
Buy and self-scheduled bids	Obligations	1	$1.28	$0.69	$0.61	$1.02
		2	$1.40	$0.36	$0.26	$0.95
		3	$1.55	$0.56	$0.53	$1.18
		4	$1.52	$0.70	$0.56	$1.18
		Total	$1.43	$0.57	$0.47	$1.07
Sell offers	Obligations	1	NA	NA	NA	NA
		2	($0.13)	$0.42	$0.24	$0.09
		3	$0.53	$0.18	$0.25	$0.26
		4	($1.05)	$0.29	$0.60	($0.11)
		Total	($0.43)	$0.28	$0.39	$0.07
	Options	1	NA	NA	NA	NA
		2	($0.13)	($4.61)	($2.52)	($4.06)
		3	$0.53	($0.24)	($0.20)	($0.22)
		4	($0.83)	($0.66)	($0.08)	($0.30)
		Total	($0.83)	($1.58)	($0.35)	($0.94)

The 2007 to 2008 planning period price duration curve for cleared buy bids in Figure 8-1 shows that 85 percent of annual FTRs were purchased for less than $1 per MWh, 90.9 percent for less than $2 per MWh and 93.4 percent for less than $3 per MWh. Negative prices occur because some FTRs are bid with negative prices and some winning FTR bidders are paid to take FTRs.

Figure 8-1 Annual FTR auction-clearing price duration curve: Planning period 2007 to 2008

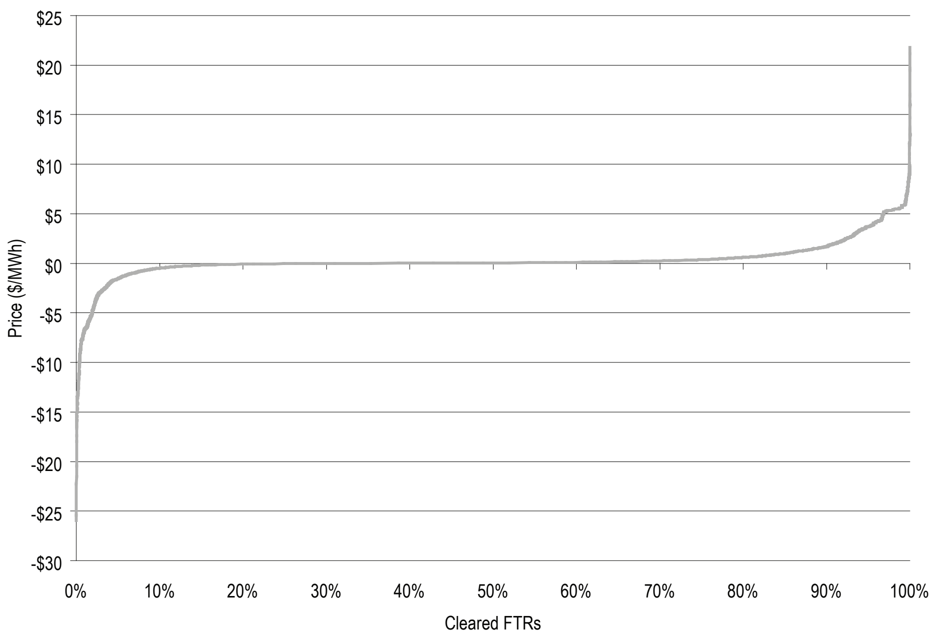


Table 8-10 shows the weighted-average cleared buy-bid price in the Monthly Balance of Planning Period FTR Auctions by bidding period for January 2007 through December 2007. For example, for the June 2007 Monthly Balance of Planning Period FTR Auction, the current month column is June, the second month column is July and the third month column is August. Quarters 1 through 4 are represented in the Q1, Q2, Q3 and Q4 columns. The total column represents all of the activity within the June 2007 Monthly Balance of Planning Period FTR Auction.

The cleared, weighted-average price paid in the Monthly Balance of Planning Period FTR Auctions during the first seven months of the 2007 to 2008 planning period was $0.18 per MWh, compared with $0.22 per MWh for the full 12-month 2006 to 2007 planning period.

Table 8-10 Monthly Balance of Planning Period FTR Auction cleared, weighted-average, buy-bid price per period (Dollars per MWh): January 2007 to December 2007

Monthly Auction	Current Month	Second Month	Third Month	Q1	Q2	Q3	Q4	Total
Jan-07	$0.13	$0.20	($0.06)				$0.45	$0.14
Feb-07	$0.03	$0.13	$0.02				$0.19	$0.07
Mar-07	$0.05	($0.15)	($0.16)				$0.84	$0.11
Apr-07	$0.15	$0.19						$0.16
May-07	$0.11							$0.11
Jun-07	$0.14	$0.33	($0.09)	$0.45	($0.03)	$0.28	$0.09	$0.16
Jul-07	$0.32	$0.92	$0.06		$0.26	$0.41	$0.51	$0.41
Aug-07	$0.19	$0.33	$0.17		$0.14	$0.28	$0.29	$0.23
Sep-07	$0.12	$0.23	$0.11		($0.06)	$0.22	$0.09	$0.12
Oct-07	$0.06	$0.18	$0.01			$0.24	$0.16	$0.11
Nov-07	$0.10	($0.22)	$0.03			$0.34	$0.10	$0.13
Dec-07	$0.05	$0.19	$0.24			$0.25	$0.13	$0.12

Revenue

Annual FTR Auction Revenue

Table 8-11 shows Annual FTR Auction revenue data by trade type, auction round and class type. For the 2007 to 2008 planning period, the Annual FTR Auction netted $1,698.03 million in revenue, with buyers paying $1,698.28 million and sellers receiving $0.25 million. For the 2006 to 2007 planning period, the Annual FTR Auction netted $1,417.5 million in revenue, with buyers paying $1,453 million and sellers receiving $35.5 million.

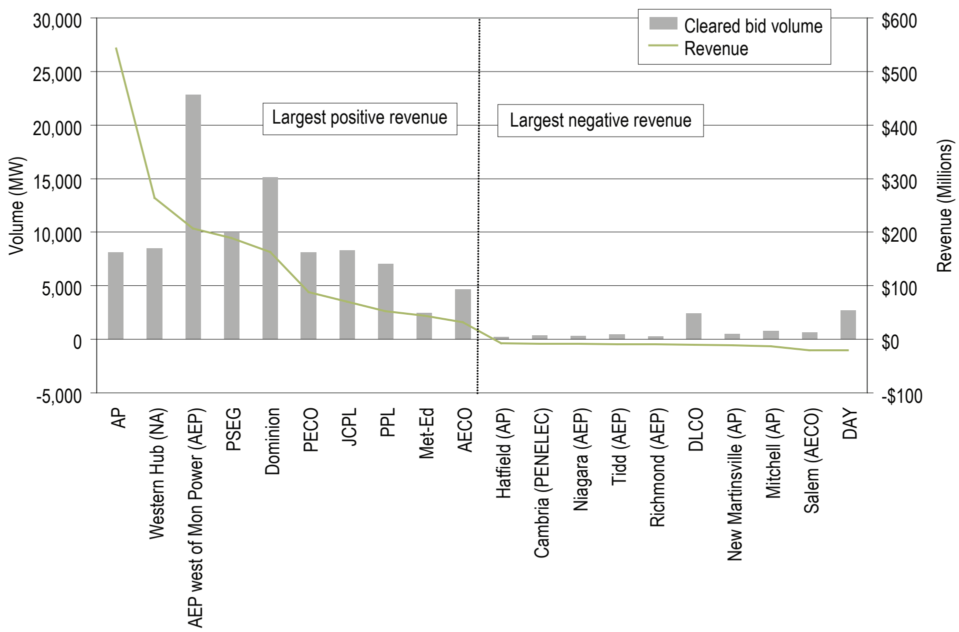
Table 8-11 Annual FTR Auction revenue: Planning period 2007 to 2008

		Class Type			
Trade Type	Auction Round	24-Hour	On Peak	Off Peak	All
Buy bids	1	$8,446,917	$73,952,697	$45,070,233	$127,469,847
	2	$54,204,137	$40,426,599	$28,626,993	$123,257,729
	3	$27,360,401	$52,798,932	$35,302,820	$115,462,153
	4	$17,004,914	$59,503,404	$38,714,096	$115,222,414
	Total	$107,016,369	$226,681,632	$147,714,142	$481,412,143
Self-scheduled bids	1	$302,959,854	NA	NA	$302,959,854
	2	$306,899,628	NA	NA	$306,899,628
	3	$305,327,391	NA	NA	$305,327,391
	4	$301,683,335	NA	NA	$301,683,335
	Total	$1,216,870,208	NA	NA	$1,216,870,208
Buy and self-scheduled bids	1	$311,406,771	$73,952,697	$45,070,233	$430,429,701
	2	$361,103,765	$40,426,599	$28,626,993	$430,157,357
	3	$332,687,792	$52,798,932	$35,302,820	$420,789,544
	4	$318,688,249	$59,503,404	$38,714,096	$416,905,749
	Total	$1,323,886,577	$226,681,632	$147,714,142	$1,698,282,351
Sell offers	1	NA	NA	NA	NA
	2	($595,128)	($427,175)	($35,394)	($1,057,697)
	3	$816,645	$721,027	$967,389	$2,505,061
	4	($4,782,618)	$1,002,334	$2,087,605	($1,692,679)
	Total	($4,561,101)	$1,296,186	$3,019,600	($245,315)

Figure 8-2 summarizes total revenue associated with all FTRs, regardless of source, to the FTR sinks that produced the largest positive and negative revenue from the Annual FTR Auction for the 2007 to 2008 planning period.[19] The top 10 positive revenue producing FTR sinks accounted for $1,653.9 million (97.4 percent) of the total revenue of $1,698.03 million paid in the auction. They also comprised 33.2 percent of all FTRs bought in the auction. The sinks with the highest positive auction revenue are all control zones or large aggregates. The top 10 negative revenue producing FTR sinks accounted for -$117.2 million of revenue and constituted 2.9 percent of all FTRs bought in the auction.

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

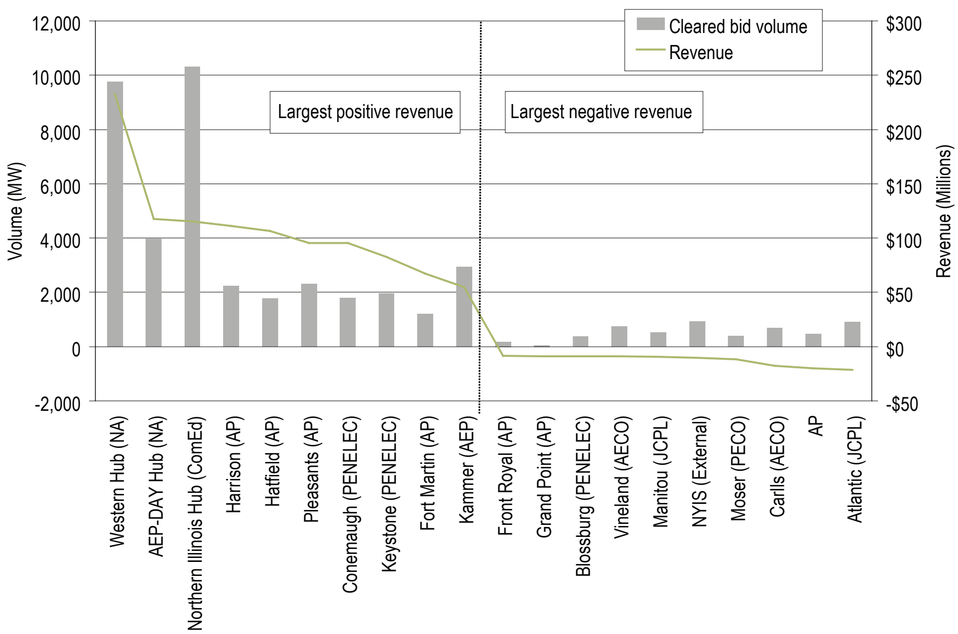
Figure 8-2 Ten largest positive and negative revenue producing FTR sinks purchased in the Annual FTR Auction: Planning period 2007 to 2008[20]



20 For Figure 8-2 through Figure 8-7, each FTR sink and source that is not a control zone has its corresponding control zone listed in parenthesis after its name. Most FTR sink and source control zone identifications for hubs; interface pricing points are listed as NA because they cannot be assigned to a specific control zone.

Figure 8-3 summarizes total revenue associated with all FTRs, regardless of sink, from the FTR sources that produced the largest positive and negative revenue from the Annual FTR Auction for the 2007 to 2008 planning period. The top 10 positive revenue producing FTR sources accounted for $1,077.8 million (63.5 percent) of the total revenue of $1,698.03 million paid in the auction. They also comprised 13.3 percent of all FTRs bought in the auction. The top 10 negative revenue producing FTR sources accounted for -$125.4 million of revenue and constituted 1.8 percent of all FTRs bought in the auction.

Figure 8-3 Ten largest positive and negative revenue producing FTR sources purchased in the Annual FTR Auction: Planning period 2007 to 2008



Monthly Balance of Planning Period FTR Auction Revenue

Table 8-12 shows Monthly Balance of Planning Period FTR Auction revenue data by trade type and class type. For the 2007 to 2008 planning period through December 31, 2007, the Monthly Balance of Planning Period FTR Auctions netted $28.2 million in revenue, with buyers paying $62.2 million and sellers receiving $34 million. For the 2006 to 2007 planning period, the Monthly Balance of Planning Period FTR Auctions netted $17.2 million in revenue, with buyers paying $71.2 million and sellers receiving $54 million.

Table 8-12 Monthly Balance of Planning Period FTR Auction revenue: January 2007 to December 2007

Monthly Auction	Trade Type	Class Type			
		24-Hour	On Peak	Off Peak	All
Jan-07	Buy bids	$583,017	$2,883,069	$964,794	$4,430,880
	Sell offers	($721,226)	($2,090,817)	($328,769)	($3,140,812)
Feb-07	Buy bids	($3,768,019)	$3,399,267	$2,400,432	$2,031,680
	Sell offers	($649,464)	($1,072,643)	$25,121	($1,696,986)
Mar-07	Buy bids	$1,656,411	$712,695	$1,198,393	$3,567,499
	Sell offers	($567,082)	($915,103)	($1,277,279)	($2,759,464)
Apr-07	Buy bids	($505,488)	$1,974,040	$1,085,023	$2,553,575
	Sell offers	($303,963)	($1,043,921)	($547,857)	($1,895,741)
May-07	Buy bids	$259,746	$1,043,126	$631,131	$1,934,003
	Sell offers	($360,056)	($717,855)	($307,251)	($1,385,162)
Jun-07	Buy bids	$7,101,255	$690,771	$218,269	$8,010,295
	Sell offers	($3,941,208)	$1,022,876	($1,207,028)	($4,125,360)
Jul-07	Buy bids	$5,164,135	$10,221,230	$3,343,105	$18,728,470
	Sell offers	($3,224,602)	($7,530,502)	($2,793,025)	($13,548,129)
Aug-07	Buy bids	$1,904,748	$8,485,750	$2,981,821	$13,372,319
	Sell offers	($1,574,195)	($4,719,109)	($1,074,102)	($7,367,406)
Sep-07	Buy bids	$982,636	$4,564,365	$1,016,093	$6,563,094
	Sell offers	($991,670)	($2,912,997)	$525,664	($3,379,003)
Oct-07	Buy bids	($245,677)	$5,902,053	$1,068,982	$6,725,358
	Sell offers	($1,816,099)	($2,050,370)	$1,304,930	($2,561,539)
Nov-07	Buy bids	($1,729,412)	$4,654,263	$1,978,845	$4,903,696
	Sell offers	($2,195,950)	($848,295)	$1,173,866	($1,870,379)
Dec-07	Buy bids	$765,152	$1,935,346	$1,234,802	$3,935,300
	Sell offers	($921,537)	($376,631)	$165,582	($1,132,586)

Figure 8-4 summarizes total revenue associated with all FTRs, regardless of source, to the FTR sinks that produced the largest positive and negative revenue in the Monthly Balance of Planning Period FTR Auctions during the first seven months of the 2007 to 2008 planning period. The top 10 positive revenue producing FTR sinks accounted for $99.5 million of revenue and 8.2 percent of all FTRs bought in the Monthly Balance of Planning Period FTR Auctions. There were 6,132 MW cleared out of 32,697 MW bid for FTRs sunk into the new Neptune 230 kV line which generated $6.3 million of revenue. The top 10 negative revenue producing FTR sinks accounted for -$36.7 million of revenue and constituted 6.4 percent of all FTRs bought in the auctions.

Figure 8-4 Ten largest positive and negative revenue producing FTR sinks purchased in the Monthly Balance of Planning Period FTR Auctions: Planning period 2007 to 2008 through December 31, 2007

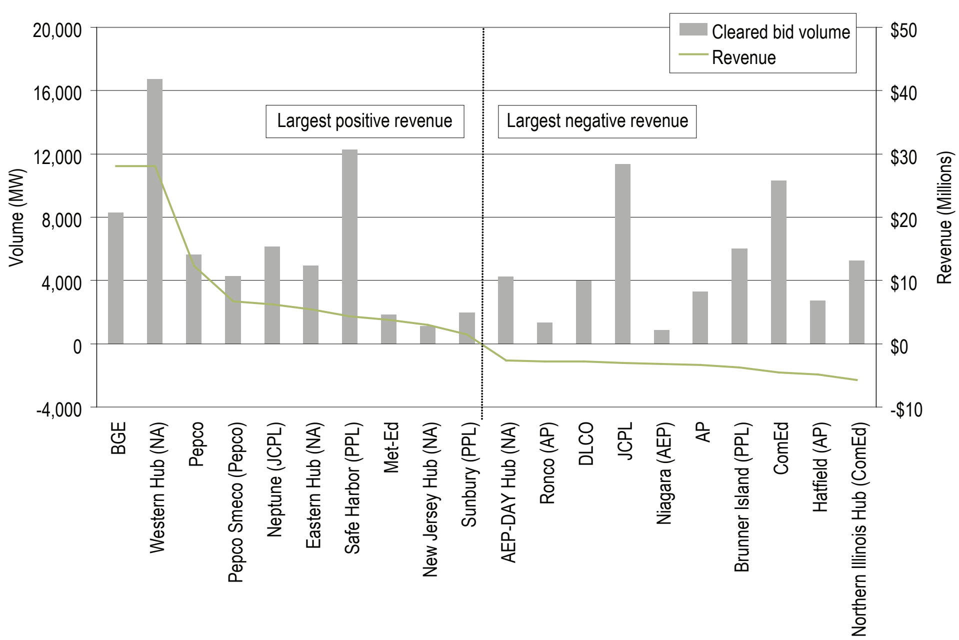
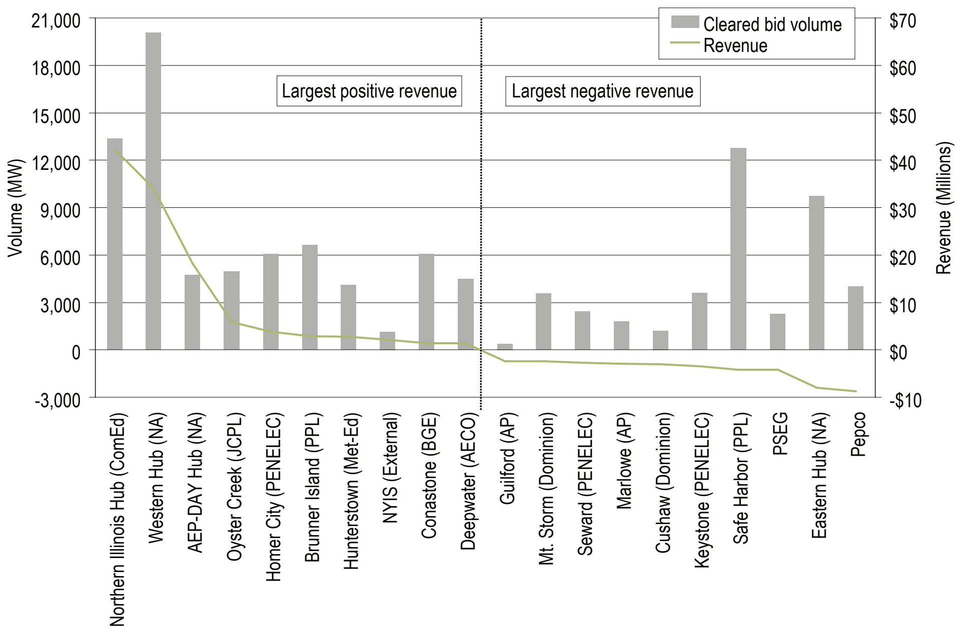


Figure 8-5 summarizes total revenue associated with all FTRs, regardless of sink, from the FTR sources that produced the largest positive and negative revenue from the Monthly Balance of Planning Period FTR Auctions during the first seven months of the 2007 to 2008 planning period. The top 10 positive revenue producing FTR sources accounted for $114.8 million and 9.3 percent of all FTRs bought in the auctions. The top 10 negative revenue producing FTR sources accounted for -$42.1 million of revenue and constituted 5.4 percent of all FTRs bought in the auctions.

Figure 8-5 Ten largest positive and negative revenue producing FTR sources purchased in the Monthly Balance of Planning Period FTR Auctions: Planning period 2007 to 2008 through December 31, 2007



Revenue Adequacy

Congestion revenue is created in an LMP system when all loads pay and all generators receive their respective LMPs. When load pays more than the amount that generators receive, excluding losses, positive congestion revenue exists and is available to cover the target allocations of FTR holders. The MW of load exceeds the MW of generation in constrained areas because a part of the load is served by imports using transmission capability into the constrained areas. Generating units that are the source of such imports are paid the price at their own bus which does not reflect congestion in constrained areas. Generation in a constrained area receives the congested price and all load in the constrained area pays the congested price. As a result, load congestion payments are usually greater than the congestion-related increase in payments to generation.[21] In general, FTR revenue adequacy exists when the sum of congestion credits is as great as the sum of congestion across the positively valued FTRs.

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.

21 For an illustration of how total congestion revenue is generated and how FTR target allocations and congestion receipts are determined, see Table G-1, "Congestion revenue, FTR target allocations and FTR congestion credits: Illustration," *2007 State of the Market Report*, Volume II, Appendix G, "Financial Transmission and Auction Revenue Rights."

Table 8-13 shows the composition of FTR target allocations and FTR revenues for the 2006 to 2007 and the 2007 to 2008 planning periods, with the latter shown through December 31, 2007. FTR targets are composed of FTR target allocations and associated adjustments. Other adjustments may be made for items such as modeling changes or errors.

FTR revenues are primarily comprised of hourly congestion revenue and net negative congestion. FTR revenues also include ARR excess which is the difference between ARR target allocations and FTR auction revenues. Competing use revenues are based on the Unscheduled Transmission Service Agreement between the New York Independent System Operator (NYISO) and PJM. This agreement sets forth the terms and conditions under which compensation is provided for transmission service in connection with transactions not scheduled directly or otherwise prearranged between NYISO and PJM. Congestion revenues appearing in Table 8-13 include both congestion charges associated with PJM facilities and those associated with reciprocal, coordinated flowgates in the Midwest ISO whose operating limits are respected by PJM.[22] The operating protocol governing the wheeling contracts between Public Service Electric and Gas Company (PSE&G) and Consolidated Edison Company of New York (Con Edison) resulted in a reimbursement of $1.4 million in congestion charges to Con Edison in the 2007 to 2008 planning period through December 31, 2007.[23, 24]

22 See “Joint Operating Agreement between the Midwest Independent System Operator, Inc. and PJM Interconnection, L.L.C.” (December 31, 2003), Substitute Original Sheet No. 66 <http://www.pjm.com/documents/downloads/agreements/joa-complete.pdf> (1,331 KB).

23 111 FERC ¶ 61,228 (2005).

24 See the *2007 State of the Market Report*, Volume II, Section 4, “Interchange Transactions,” at “Con Edison and PSE&G Wheeling Contracts 2007 Update” and Appendix D, “Interchange Transactions” at Table D-1, “Con Edison and PSE&G wheel settlements data: Calendar year 2007.”

Table 8-13 Total annual PJM FTR revenue detail (Dollars (Millions)): Planning periods 2006 to 2007 and 2007 to 2008

Accounting Element	2006/2007	2007/2008*
ARR information		
ARR target allocations	$1,392.8	$959.9
FTR auction revenue	$1,434.8	$1,009.5
ARR excess	$41.9	$49.6
FTR targets		
FTR target allocations	$1,724.8	$1,197.9
Adjustments:		
Adjustments to FTR target allocations	($1.8)	($2.5)
Total FTR targets	$1,723.0	$1,195.5
FTR revenues		
ARR excess	$41.9	$49.6
Competing uses	$0.8	$0.4
Hourly congestion revenue		
Day ahead	$1,878.7	$1,345.3
Balancing	($155.9)	($144.5)
Midwest ISO M2M (credit to PJM minus credit to Midwest ISO)	$1.1	($8.8)
Consolidated Edison Company of New York and Public Service Electric and Gas Company Wheel (CEPSW) congestion credit to Con Edison	($2.6)	($1.4)
Adjustments:		
Excess revenues carried forward into future months	$138.8	$296.9
Excess revenues distributed back to previous months	$6.6	$0.0
Other adjustments to FTR revenues	($2.9)	$0.5
Total FTR revenues	$1,906.1	$1,532.7
Excess revenues distributed to other months	($183.1)	($337.3)
Excess revenues distributed to CEPSW for end-of-year distribution	$0.0	$0.0
Excess revenues distributed to firm demand holders	$37.5	$0.0
Total FTR congestion credits	$1,723.0	$1,195.5
Total congestion credits on bill (includes CEPSW and end-of-year distribution)	$1,763.3	$1,196.8
Remaining deficiency	$0.0	$0.0
* Shows seven months ended 31-Dec-07		

FTR target allocations are based on hourly prices in the Day-Ahead Energy Market for the respective FTR paths and equal the revenue required to hedge FTR holders fully against congestion on the specific paths for which the FTRs are held. FTR credits are paid to FTR holders and, depending on market conditions, can be less than the target allocations. Table 8-14 lists the FTR revenues, target allocations, credits, payout ratios, congestion credit deficiencies and excess congestion charges by month. At the end of the 12-month planning period, excess congestion charges are used to offset any monthly congestion credit deficiencies. FTRs were paid at 100 percent of the target allocation level for the 2006 to 2007 planning period and the 2007 to 2008 planning period through December 31, 2007.

Table 8-14 Monthly FTR accounting summary (Dollars (Millions)): Planning periods 2006 to 2007 and 2007 to 2008

		FTR Revenues	FTR Target Allocations	FTR Credits	FTR Payout Ratio	Credits Deficiency	Credits Excess
Planning period 2006 to 2007	Jun-06	$167.8	$167.8	$167.8	100%	$0	$0.0
	Jul-06	$298.4	$293.8	$293.8	100%	$0	$4.6
	Aug-06	$374.0	$368.0	$368.0	100%	$0	$6.0
	Sep-06	$78.8	$75.2	$75.2	100%	$0	$3.6
	Oct-06	$47.1	$45.1	$45.1	100%	$0	$2.0
	Nov-06	$49.9	$44.2	$44.2	100%	$0	$5.7
	Dec-06	$100.7	$92.1	$92.1	100%	$0	$8.6
	Jan-07	$125.8	$106.4	$106.4	100%	$0	$19.4
	Feb-07	$198.4	$175.4	$175.4	100%	$0	$23.0
	Mar-07	$186.4	$147.3	$147.3	100%	$0	$39.1
	Apr-07	$151.7	$118.3	$118.3	100%	$0	$33.4
	May-07	$127.1	$89.4	$89.4	100%	$0	$37.7
	Total	$1,906.1	$1,723.0	$1,723.0	100%	$0	$183.1
				Values after excess revenues distributed			
		$1,906.1	$1,723.0	$1,723.0	100%	$0	$183.1
Planning period 2007 to 2008 (through December 31, 2007)	Jun-07	$193.0	$178.1	$178.1	100%	$0	$14.9
	Jul-07	$227.9	$178.9	$178.9	100%	$0	$49.0
	Aug-07	$264.8	$206.3	$206.3	100%	$0	$58.5
	Sep-07	$199.0	$134.2	$134.2	100%	$0	$64.8
	Oct-07	$192.0	$130.6	$130.6	100%	$0	$61.4
	Nov-07	$180.4	$132.0	$132.0	100%	$0	$48.4
	Dec-07	$275.6	$235.4	$235.4	100%	$0	$40.2
	Total	$1,532.7	$1,195.5	$1,195.5	100%	$0	$337.2

FTR target allocations were examined separately. Hourly FTR target allocations were divided into those that were benefits and liabilities and summed by sink and by source for the 2007 to 2008 planning period through December 31, 2007. Figure 8-6 shows the FTR sinks with the largest positive and negative target allocations. The top 10 sinks that produced a financial benefit accounted for 66.3 percent of total positive target allocations during the first seven months of the 2007 to 2008 planning period. FTRs with the AP Control Zone as the sink included 22.2 percent of all positive target allocations. The sinks with the highest positive target allocations are all control zones or large aggregates. The top 10 sinks that created liability accounted for 19.8 percent of total negative target allocations. FTRs with the Western Hub as the sink encompassed 3.5 percent of all negative target allocations.

Figure 8-6 Ten largest positive and negative FTR target allocations summed by sink: Planning period 2007 to 2008 through December 31, 2007

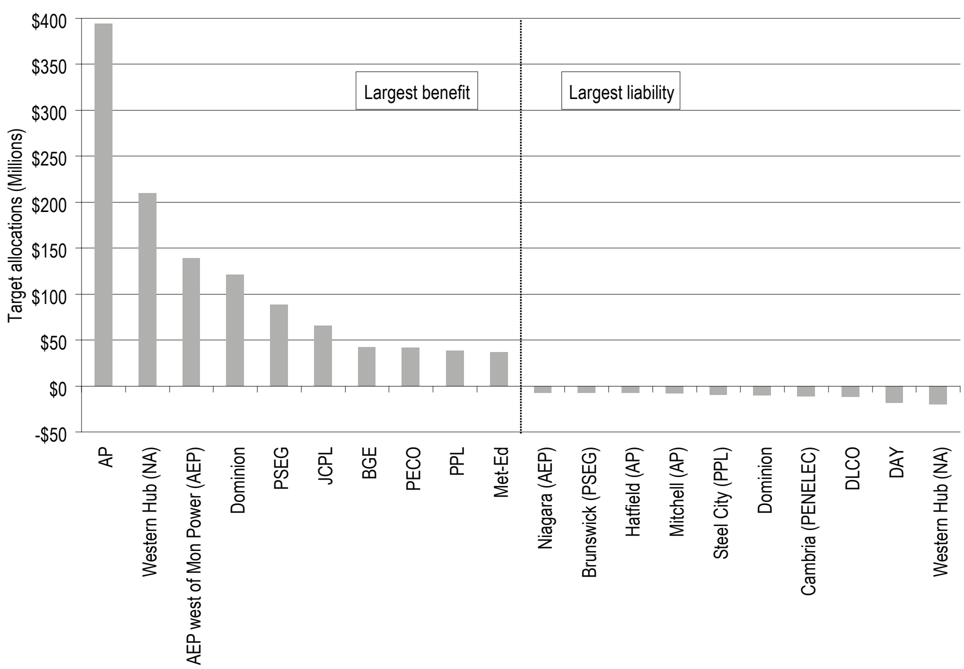
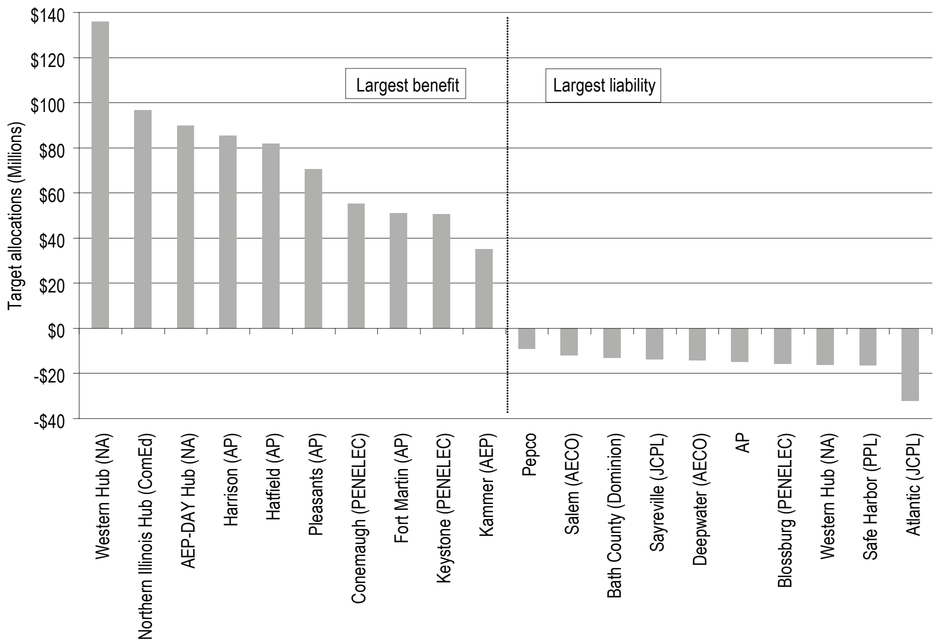


Figure 8-7 shows the FTR sources with the largest positive and negative target allocations during the first seven months of the 2007 to 2008 planning period. The top 10 sources with a positive target allocation accounted for 42.3 percent of total positive target allocations. FTRs with the Western Hub as their source included 7.6 percent of all positive target allocations. The top 10 sources with a negative target allocation accounted for 27 percent of total negative target allocations. FTRs with Atlantic as the source encompassed 5.5 percent of all negative target allocations.

Figure 8-7 Ten largest positive and negative FTR target allocations summed by source: Planning period 2007 to 2008 through December 31, 2007



Auction Revenue Rights

FTRs and ARRs are both financial instruments that entitle the holder to receive revenues or to pay charges based on nodal price differences. FTRs provide holders with revenues or charges based on the locational congestion price differences actually experienced in the Day-Ahead Energy Market while ARRs are financial instruments that entitle their holders to receive revenue or to pay charges based on prices determined in the Annual FTR Auction.[25] These price differences are based on the bid prices of participants in the Annual FTR Auction which relate to their expectations about the level of congestion in the Day-Ahead Energy Market. The auction clears the set of feasible FTR bids which produce the highest net revenue. In other words, ARR revenues are a function of FTR auction participants' expectations of locational congestion price differences in the Day-Ahead Energy Market.

25 These nodal prices are a function of the market participants' annual FTR bids and binding transmission constraints. An optimization algorithm selects the set of feasible FTR bids that produces the most net revenue.

ARRs are available to the nearest 0.1 MW. The ARR target allocation is equal to the product of the ARR MW and the price difference between sink and source from the Annual FTR Auction. An ARR value can be positive or negative depending on the sink-minus-source price difference, with a negative difference resulting in a liability for the holder. The ARR target allocation represents the revenue that an ARR holder should receive. All ARR holders receive ARR credits equal to their target allocations if total net revenues from the Annual and Monthly Balance of Planning Period FTR Auctions are greater than, or equal to, the sum of all ARR target allocations. ARR credits can be positive or negative and can range from zero to the ARR target allocation. If the combined net revenues from the Annual and Monthly Balance of Planning Period FTR Auctions are less than that, available revenue is proportionally allocated among all ARR holders.

ARRs are available only as obligation hedge type and 24-hour class type products. An ARR obligation provides a credit, positive or negative, equal to the product of the ARR MW and the price difference between ARR sink and source that occurs in the Annual FTR Auction. The 24-hour products are effective 24 hours a day, seven days a week.

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 planning periods following their integration date. After the transition period, such participants receive ARRs from the annual allocation process and are ineligible for directly allocated FTRs.

Market Structure

ARRs have been available to network service and firm, point-to-point transmission service customers since June 1, 2003, when the annual ARR allocation was first implemented for the 2003 to 2004 planning period. The initial allocation covered the Mid-Atlantic Region and the AP Control Zone. For the 2006 to 2007 planning period, the choice of ARRs or direct allocation FTRs was available to eligible market participants in the AEP, DAY, DLCO and Dominion control zones. For the 2007 to 2008 planning period, all eligible market participants were allocated ARRs.

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.

ARR Allocation

On July 20, 2006, the FERC issued an order amending its regulations under the Federal Power Act to require transmission organizations that are public utilities with organized electricity markets to make available long-term, firm transmission rights that satisfy certain conditions imposed by the final rule.[26] Before its issuance, PJM had, on July 3, 2006, submitted to the FERC revisions to its OATT to include long-term ARRs and FTRs for a duration of 10 planning periods.[27] On November 22, 2006, the FERC issued an order accepting the revisions to the PJM OATT with the stipulation that they were subject to some modifications to include an uplift mechanism to ensure that long-term ARRs and FTRs would be fully funded.[28]

26 116 FERC ¶ 61,077 (2006).

27 *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).

28 117 FERC ¶ 61,220 (2006).

On January 22, 2007, in compliance with the FERC order, PJM submitted revisions to its OATT so as to include an uplift mechanism that would fully fund all FTRs and ARRs.[29] PJM proposed to fully fund all ARRs and FTRs by allocating uplift charges on a pro-rata basis corresponding to a market participant's FTR target allocations in proportion to the sum of all market participant's FTR target allocations. On May 17, 2007, the FERC issued an order accepting these revisions while encouraging PJM to continue to explore all possible options for an uplift mechanism and requiring it to file a status report by November 30, 2007.[30] On October 22, 2007, the FERC issued an order on clarification of the May 17 order indicating that negative FTR target allocations be excluded from the uplift mechanism.[31] PJM submitted to the FERC on November 16, 2007, revisions to the OATT to exclude negative FTR target allocations from the uplift mechanism.[32] PJM filed a status report with the FERC on November 30, 2007, that stated that an alternative to the existing uplift mechanism could not be agreed upon and, therefore, the OATT would remain the same.[33] PJM will fully fund all ARRs and FTRs by allocating uplift charges on a pro-rata basis corresponding to a market participant's net positive FTR target allocations in proportion to the sum of all market participant's net positive FTR target allocations.

For the 2007 to 2008 planning period, the annual ARR allocation process was revised to include long-term ARRs that would be in effect for 10 consecutive planning periods.[34] Long-term ARRs can give LSEs the ability to hedge their congestion costs on a long-term basis by providing price certainty throughout the 10-planning-period time frame. Long-term ARR holders can opt out of any planning period during the 10-planning-period timeline and self-schedule their long-term ARRs as FTRs.

Each March, PJM allocates ARRs to eligible customers in a three-stage process, whereby the first and second stages are each one round and the third stage is a three-round allocation procedure:

- Stage 1A. In the first stage of the allocation, network transmission service customers can obtain long-term ARRs, up to their share of the zonal baseload, after taking into account generation resources that historically have served load in each control zone and up to 50 percent of their historical nonzone network load. Nonzone network load is load that is located outside of the PJM footprint. Firm, point-to-point transmission service customers can obtain long-term ARRs, based on up to 50 percent of the MW of long-term, firm, point-to-point transmission service provided between the receipt and delivery points for the historical reference year. Stage 1A ARR holders can also opt out of any planning period during the 10-planning-period timeline and self-schedule their long-term ARRs as FTRs.

29 *PJM Interconnection, L.L.C.*, PJM Interconnection, L.L.C. in compliance with the FERC's November 22, 2006, order submitted revisions to Schedule 1 of the Amended and Restated Operating Agreement, Docket No. ER06-1218-003 (January 22, 2007).

30 119 FERC ¶ 61,144 (2007).

31 121 FERC ¶ 61,073 (2007).

32 *PJM Interconnection, L.L.C.*, PJM Interconnection, L.L.C. submits revisions to the Amended & Restated Operating Agreement of PJM Interconnection, L.L.C. & its OATT to prevent the allocation of transmission rights uplift charges etc, Docket No. ER06-1218-006 (November 16, 2007).

33 *PJM Interconnection, L.L.C.*, PJM filed an informational report describing the transmission rights underfunding uplift charge allocation alternatives evaluated in the PJM stakeholder process and the results of that process, Docket No. ER06-1218-007 (November 30, 2007).

34 See the *2006 State of the Market Report* (March 8, 2007) for the rules of the annual ARR allocation process for the 2006 to 2007 and prior planning periods.

- Stage 1B. ARRs unallocated in Stage 1A are available in the Stage 1B allocation. Network transmission service customers can obtain ARRs, up to their share of the zonal peak load, based on generation resources that historically have served load in each control zone and up to 100 percent of their transmission responsibility for nonzone network load. Firm, point-to-point transmission service customers can obtain ARRs based on the MW of long-term, firm, point-to-point service provided between the receipt and delivery points for the historical reference year. These long-term point-to-point service agreements must also remain in effect for the planning period covered by the allocation.

- Stage 2. The third stage of the annual ARR allocation is a three-step procedure, with one-third of the remaining system capability allocated in each step of the process. Network transmission service customers can obtain ARRs from any hub, control zone, generator bus or interface pricing point to any part of their aggregate load in the control zone or load aggregation zone for which an ARR was not allocated in Stage 1A or Stage 1B. Firm, point-to-point transmission service customers can obtain ARRs consistent with their transmission service as in Stage 1A and Stage 1B.

Prior to the start of the Stage 2 annual ARR allocation process, ARR holders can relinquish any portion of their ARRs resulting from the Stage 1A or Stage 1B allocation process, provided that all remaining outstanding ARRs are simultaneously feasible following the return of such ARRs.[35] Participants may seek additional ARRs in the Stage 2 allocation.

ARRs can also be traded between LSEs, but these trades must be made before the first round of the Annual FTR Auction. LSEs trading ARRs must trade all of their ARRs associated with a control zone and their zonal network service peak load is also reassigned to the new LSE. Traded ARRs are effective for the full 12-month planning period.

When ARRs are allocated, all ARRs must be simultaneously feasible to ensure that the physical transmission system can support the approved set of ARRs. In making simultaneous feasibility determinations, PJM utilizes a power flow model of security-constrained dispatch that takes into account generation and transmission facility outages and is based on reasonable assumptions about the configuration and availability of transmission capability during the planning period.[36] This simultaneous feasibility requirement is necessary to ensure that there are sufficient revenues from transmission congestion charges to satisfy all resulting ARR obligations, thereby preventing underfunding of the ARR obligations for a given planning period. If the requested set of ARRs is not simultaneously feasible, customers are allocated prorated shares in direct proportion to their requested MW and in inverse proportion to their impact on binding constraints:

Equation 8-1 Calculation of prorated ARRs

Individual prorated MW =
(Constraint capability) • (Individual requested MW / Total requested MW) • (1 / MW effect on line).[37]

The effect of an ARR request on a binding constraint is measured using the ARR's power flow distribution factor. An ARR's distribution factor is the percent of each requested MW of ARR that would have a power

35 PJM. "Manual 6: Financial Transmission Rights," Revision 10 (June 1, 2007), pp. 20-23.

36 PJM. "Manual 6: Financial Transmission Rights," Revision 10 (June 1, 2007), pp. 48-49.

37 See the *2007 State of the Market Report*, Volume II, Appendix G, "Financial Transmission Rights and Auction Revenue Rights," for an illustration explaining this calculation in greater detail.

flow on the binding constraint. The PJM methodology prorates those ARR requests with the greatest impact on the binding constraint to avoid prorating more requests but having smaller or minimal impact on the binding constraint. PJM's method results in the prorating of ARRs that cause the greatest flows on the binding constraint instead of those that produce less flow on it. Were all ARR requests prorated equally, irrespective of their proportional impact on the binding constraints, the result would be a significant reduction in market participants' ARRs even when they have little impact on the binding constraints and the reduction of ARRs, and their associated benefits, with primary impacts on unrelated constraints.

Residual ARRs

On June 19, 2007, PJM submitted to the FERC revisions to the OATT to include a new type of ARR known as a residual ARR.[38] On August 13, 2007, the FERC issued an order accepting the revisions to the PJM OATT with an effective date of August 20, 2007.[39] Only ARR holders that had their Stage 1A or Stage 1B ARRs prorated are eligible to receive residual ARRs. Residual ARRs would be available if additional transmission system capability were added during the planning period after the annual ARR allocation. This additional transmission system capability would not have been accounted for in the initial annual ARR allocation, but it enables the creation of residual ARRs. Residual ARRs would be effective on the first day of the month in which the additional transmission system capability is included in FTR auctions and would exist until the end of the planning period. For the following planning period, any residual ARRs would be available as ARRs in the annual ARR allocation process as they would be included in the power flow model. The amount of a residual ARR would be the difference between the ARR holder's Stage 1A or Stage 1B request and their actual prorated Stage 1A or Stage 1B ARR MW. Stage 1 ARR holders have a priority right to ARRs and those holders who had ARRs prorated because of the simultaneous feasibility requirement previously had no recourse from the impact of proration. Residual ARRs are a separate product from incremental ARRs.

Incremental ARRs

Market participants constructing generation interconnection or transmission expansion projects may request an allocation of incremental ARRs consistent with the project's increased transmission capability.[40] Incremental ARRs are available in a three-round allocation process with a single point-to-point combination requested and one-third of the incremental ARR MW allocated in each round. Incremental ARRs can be accepted or refused after rounds one and two. If accepted, that ARR is removed from availability in subsequent rounds; if it is refused, that ARR is available in the next rounds. Such incremental ARRs are effective for the lesser of 30 years or the life of the facility or upgrade. At any time during this 30-year period, in place of continuing this 30-year ARR, the participant has a single opportunity to replace the allocated ARRs with a right to request ARRs during the annual ARR allocation process between the same source and sink. Such participants can also permanently relinquish their incremental ARRs at any time during the life of the ARRs as long as overall the system simultaneous feasibility can be maintained.

38 *PJM Interconnection, L.L.C.*, PJM Interconnection, L.L.C. submits revisions to its Amended and Restated Operating Agreement and Open Access Transmission Tariff pursuant to Section 205 of the Federal Power Act, Docket No. ER07-1053-000 (June 19, 2007).

39 *PJM Interconnection, L.L.C.*, Letter Order accepting PJM Interconnection, L.L.C.'s June 19, 2007, filing of Second Revised Sheet No. 6A *et al* to the Third Revised Rate Schedule, FERC No. 24 *et al*, Docket No. ER07-1053-000 (August 13, 2007).

40 PJM. "Manual 6: Financial Transmission Rights," Revision 10 (June 1, 2007), p. 28.

Table 8-15 lists the top 10 principal binding constraints, along with their corresponding control zones in order of severity, that limited supply in the annual ARR allocation for the 2007 to 2008 planning period. The order of severity is determined by the violation degree of the binding constraint as computed in the simultaneous feasibility test.[41] The violation degree is a measure of the MW that a constraint is over the limit for a type of facility; a higher number indicates a more severe constraint.

Table 8-15 Top 10 principal binding transmission constraints limiting the annual ARR allocation: Planning period 2007 to 2008

Constraint	Type	Control Zone
Bedington - Black Oak	Interface	AP
AP South	Interface	AP
Meadowbrook	Transformer	AP
Cedar Grove - Clifton	Line	PSEG
Whitpain	Transformer	PECO
East Frankfort - Goodings Grove	Line	ComEd
Coneprep	Transformer	AEP
Barbadoes - Plymouth Meeting	Line	PECO
Glasgow - Mount Pleasant	Line	DPL
Manor - South Akron	Line	PPL

Demand

PJM's OATT specifies the types of transmission services that are available to eligible customers. Eligible customers submit requests to PJM for network and firm, point-to-point transmission service through the PJM Open Access Same-Time Information System (OASIS). ARRs associated with firm transmission service that spans the entire next planning period, outside of the annual ARR allocation window, can also be requested through the PJM OASIS.[42] PJM evaluates each transmission service request for its impact on the system and approves or denies the request accordingly. All approved transmission services can be accommodated by the PJM transmission system. Theoretically, since total eligible ARR demand for the system cannot exceed the combined MW of network and firm, point-to-point transmission service, ARR supply should equal ARR demand if ARR nominations are consistent with the historic use of the transmission system. However, the demand for some ARRs could be left unmet if the same resources are nominated as ARR source points by multiple parties for delivery across shared paths and the result exceeds the stated capability of the transmission system to deliver from those sources to load. The combination might not be simultaneously feasible. When the requested set of ARRs is not simultaneously feasible, customers are allocated prorated shares in direct proportion to their requested MW and in inverse proportion to their impact on binding constraints.

ARR Reassignment for Retail Load Switching

Current PJM rules provide that when load switches among LSEs during the planning period, a proportional share of associated ARRs that sink into a given control or load aggregation zone is automatically reassigned

41 PJM. "Manual 6: Financial Transmission Rights," Revision 10 (June 1, 2007), pp. 48-49.

42 PJM. "Manual 6: Financial Transmission Rights," Revision 10 (June 1, 2007), pp. 16-17.

to follow that load.[43] ARR reassignment occurs daily only if the LSE losing load has ARRs with a net positive economic value to that control zone. An LSE gaining load in the same control zone is allocated a proportional share of positively valued ARRs within the control zone based on the shifted load. ARRs are reassigned to the nearest 0.001 MW and any MW of load may be reassigned multiple times over a planning period. Residual ARRs are also subject to the rules of ARR reassignment. This practice supports competition by ensuring that the hedge against congestion follows load, thereby removing a barrier to competition among LSEs and, by ensuring that only ARRs with a positive value are reassigned, preventing an LSE from assigning poor ARR choices to other LSEs. However, when ARRs are self-scheduled as FTRs, these underlying self-scheduled FTRs do not follow load that shifts while the ARRs do follow load that shifts, and this may diminish the value of the hedge. When load shifts from one LSE to another in newly integrated control zones, directly allocated FTRs with positive economic value follow the load.[44]

Table 8-16 summarizes ARR MW and associated revenue automatically reassigned for network load in each control zone where changes occurred between June 2006 and December 2007. About 10,054 MW of ARRs associated with $326,800 per MW-day of revenue were automatically reassigned in the first seven months of the 2007 to 2008 planning period. About 20,633 MW of ARRs with $381,300 per MW-day of revenue were reassigned for the entire 12-month 2006 to 2007 planning period.

Table 8-16 ARRs and ARR revenue automatically reassigned for network load changes by control zone: June 1, 2006, to December 31, 2007

	ARRs Reassigned (MW-day)		ARR Revenue Reassigned [Dollars (Thousands) per MW-day]	
Control Zone	2006/2007 (12 months)	2007/2008 (7 months)*	2006/2007 (12 months)	2007/2008 (7 months)*
AECO	151	142	$5.9	$3.8
AEP	267	27	$1.5	$1.1
AP	384	909	$79.5	$166.8
BGE	5,833	2,260	$143.0	$58.4
ComEd	7,282	2,428	$7.5	$5.6
DAY	4	0	$0.0	$0.0
DLCO	809	293	$3.2	$0.4
Dominion	2	21	$0.1	$0.0
DPL	1,132	1,096	$15.8	$15.4
JCPL	437	423	$9.9	$8.3
Met-Ed	420	3	$19.7	$0.1
PECO	111	34	$4.2	$1.2
PENELEC	175	3	$8.3	$0.1
Pepco	2,662	1,513	$50.0	$34.2
PPL	21	9	$1.0	$0.3
PSEG	936	879	$31.7	$31.0
RECO	7	14	$0.0	$0.1
Total	20,633	10,054	$381.3	$326.8
* Through 31-Dec-07				

43 PJM. "Manual 6: Financial Transmission Rights," Revision 10 (June 1, 2007), p. 26.
44 PJM. "Manual 6: Financial Transmission Rights," Revision 10 (June 1, 2007), p. 33.

Market Performance

Volume

Table 8-17 lists the annual ARR allocation volume by stage and round for the 2006 to 2007 and the 2007 to 2008 planning periods. For the 2007 to 2008 planning period, there were 62,220 MW (41.25 percent of total demand) bid in Stage 1A, 31,063 MW (20.60 percent of total demand) bid in Stage 1B and 57,539 MW (38.15 percent of total demand) bid in Stage 2. Of 150,822 MW in total ARR requests, 62,211 MW were allocated in Stage 1A and 29,444 MW were allocated in Stage 1B while 16,337 MW were allocated in Stage 2 for a total of 107,992 MW (71.6 percent) allocated. Eligible market participants subsequently converted 71,360 MW of these allocated ARRs into annual FTRs (66.1 percent of total allocated ARRs), leaving 36,632 MW of ARRs outstanding. For the 2006 to 2007 planning period, there had been 56,705 MW (57 percent of total demand) bid in Stage 1 and 42,707 MW (43 percent of total demand) bid in Stage 2. Of 99,412 MW in total ARR requests, 54,430 MW were allocated in Stage 1 while 13,138 MW were allocated in Stage 2 for a total of 67,568 MW (68 percent) allocated. There were 38,301 MW or 56.7 percent of the allocated ARRs converted into FTRs. Immediately after the Stage 1B ARR allocation for the 2007 to 2008 planning period, ARR holders relinquished 9.6 MW of the allocated Stage 1A ARRs and 459.7 MW of the allocated Stage 1B ARRs. In comparison, no ARRs were relinquished after the Stage 1 ARR allocation for the 2006 to 2007 planning period. The uncleared volume in Table 8-17 includes ARRs that were relinquished.

Demand for ARRs increased because of load growth and the requirement for the AEP, DAY, DLCO and Dominion control zones to select ARR allocations, instead of direct allocation FTRs.

Table 8-17 Annual ARR allocation volume: Planning periods 2006 to 2007 and 2007 to 2008

Planning Period	Stage	Round	Bid and Requested Count	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Uncleared Volume (MW)	Uncleared Volume
2006/2007	1	0	7,294	56,705	54,430	96.0%	2,275	4.0%
	2	1	1,445	11,610	3,518	30.3%	8,092	69.7%
		2	847	9,929	3,367	33.9%	6,562	66.1%
		3	670	10,374	3,076	29.7%	7,298	70.3%
		4	617	10,794	3,177	29.4%	7,617	70.6%
		Total	3,579	42,707	13,138	30.8%	29,569	69.2%
	Total		10,873	99,412	67,568	68.0%	31,844	32.0%
2007/2008	1A	0	7,578	62,220	62,211	100.0%	9	0.0%
	1B	1	3,486	31,063	29,444	94.8%	1,619	5.2%
	2	2	1,922	19,360	4,043	20.9%	15,317	79.1%
		3	1,466	19,312	5,211	27.0%	14,101	73.0%
		4	1,072	18,867	7,083	37.5%	11,784	62.5%
		Total	4,460	57,539	16,337	28.4%	41,202	71.6%
	Total		15,524	150,822	107,992	71.6%	42,830	28.4%

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

The degree to which ARR credits provide a hedge against congestion on specific ARR paths is determined by the prices that result from the Annual FTR Auction. The resultant ARR credit could be greater than, less than, or equal to the actual congestion on the selected path. This is the same concept as FTR revenue adequacy.

Customers that are allocated ARRs can choose to retain the underlying FTRs linked to their ARRs through a process termed self-scheduling. Just like any other FTR, the underlying FTRs have a target hedge value based on actual day-ahead congestion on the selected path.

As with FTRs, revenue adequacy for ARRs must be distinguished from the adequacy of ARRs as a hedge against congestion. Revenue adequacy is a narrower concept that compares the revenues available to cover congestion across specific paths for which ARRs were available and allocated. The adequacy of ARRs as a hedge against congestion compares ARR revenues to total congestion sinking in the participant's load zone as a measure of the extent to which ARRs hedged market participants against actual, total congestion into their zone, regardless of the availability or allocation of ARRs.

ARR holders will receive $1,640 million in credits from the Annual FTR Auction during the 2007 to 2008 planning period, with an average hourly ARR credit of $1.73 per MWh. During the comparable 2006 to 2007 planning period, ARR holders received $1,405 million in ARR credits, with an average hourly ARR credit of $2.37 per MWh.

Table 8-18 lists ARR target allocations and net revenue sources from the Annual and Monthly Balance of Planning Period FTR Auctions for the 2006 to 2007 and the 2007 to 2008 (through December 31, 2007) planning periods. Annual FTR Auction net revenue has been sufficient to cover ARR target allocations for both planning periods. The 2007 to 2008 planning period's Annual and Monthly Balance of Planning Period FTR Auctions generated a surplus of $86 million in auction net revenue through December 31, 2007, above the amount needed to pay 100 percent of ARR target allocations. The whole 2006 to 2007 planning period's Annual and Monthly Balance of Planning Period FTR Auctions generated a surplus of $30 million in auction net revenue, above the amount needed to pay 100 percent of ARR target allocations.

Table 8-18 ARR revenue adequacy (Dollars (Millions)): Planning periods 2006 to 2007 and 2007 to 2008

	2006/2007	2007/2008
Total FTR auction net revenue	$1,435	$1,726
Annual FTR Auction net revenue	$1,418	$1,698
Monthly Balance of Planning Period FTR Auction net revenue*	$17	$28
ARR target allocations	$1,405	$1,640
ARR credits	$1,405	$1,640
Surplus auction revenue	$30	$86
ARR payout ratio	100%	100%
FTR payout ratio*	100%	100%
* Shows 12 months for 2006/2007 and seven months ended 31-Dec-07 for 2007/2008		

ARR Proration

During the annual ARR allocation process, all ARRs must be simultaneously feasible to ensure that the physical transmission system can support the approved set of ARRs. If all the ARR requests made during the annual ARR allocation process are not feasible, then ARRs are prorated and allocated in proportion to the MW level requested and in inverse proportion to the effect on the binding constraints.[45, 46]

When ARRs were allocated for the 2007 to 2008 planning period, some of the requested ARRs were prorated in order to ensure simultaneous feasibility. There were no ARRs prorated in Stage 1A of the annual ARR allocation. The Cedar Grove — Clifton line was the only binding constraint in Stage 1B of the annual ARR allocation, leading to 1,159.3 MW of proration.

A number of factors caused the proration of requested ARRs on the Cedar Grove — Clifton line. They include an increase in ARR requests for congested paths on the Cedar Grove — Clifton line, general load growth and increased unscheduled transmission flow across the PJM system from external sources.

ARR and FTR Revenue and Congestion

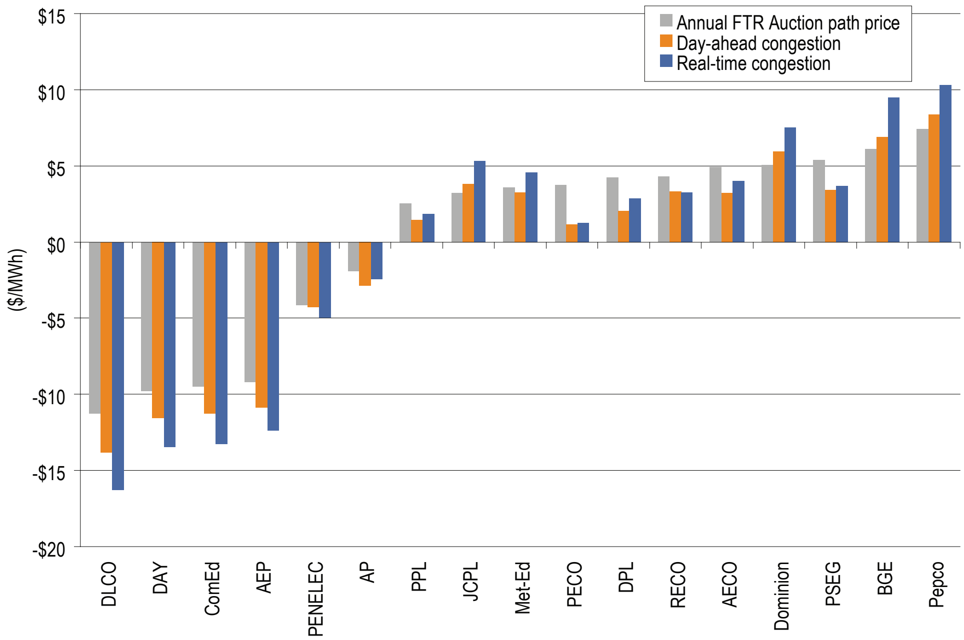
FTR Prices and Zonal Price Differences

As an illustration of the relationship between FTRs and congestion, Figure 8-8 shows Annual FTR Auction prices and an approximate measure of day-ahead and real-time congestion for each PJM control zone for the 2007 to 2008 planning period through December 31, 2007. The day-ahead and real-time congestion are based on the difference between zonal congestion prices and Western Hub congestion prices. The figure shows, for example, that an FTR from the Western Hub to the PECO Control Zone cost $3.74 per MWh in the Annual FTR Auction and that about $1.17 per MWh of day-ahead congestion and $1.26 per MWh of real-time congestion existed between the Western Hub and the PECO Control Zone. The data show that congestion costs, approximated in this way, were positive for most control zones that are located east of the Western Hub while congestion costs were negative and were more negative than the negative price of FTRs for control zones that are located west of that hub.

45 PJM. "Manual 6: Financial Transmission Rights," Revision 10 (June 1, 2007), p. 25.

46 See the *2007 State of the Market Report*, Volume II, Appendix G, "Financial Transmission Rights and Auction Revenue Rights," for an illustration explaining the ARR prorating method.

Figure 8-8 Annual FTR Auction prices vs. average day-ahead and real-time congestion for all control zones relative to the Western Hub: Planning period 2007 to 2008 through December 31, 2007



Effectiveness of ARRs as a Hedge against Congestion

One measure of the effectiveness of ARRs as a hedge against congestion is a comparison of the revenue received by the holders of ARRs and the congestion across the corresponding paths. The revenue which serves as a hedge for ARR holders comes from the FTR auctions while the hedge for FTR holders is provided by the congestion payments derived directly from the Day-Ahead Energy Market and the balancing energy market. Thus, ARRs are an indirect hedge against actual congestion in both the Day-Ahead Energy Market and the balancing energy market.

The comparison between the revenue received by ARR holders and the actual congestion experienced by these ARR holders in the Day-Ahead Energy Market and the balancing energy market is presented by control zone in Table 8-19. ARRs and self-scheduled FTRs that sink at an aggregate are assigned to a control zone if applicable.[47] Total revenue equals the ARR credits and the FTR credits from ARRs which are self-scheduled as FTRs. The ARR credits do not include the credits for the portion of any ARR that was self-scheduled as an FTR since ARR holders purchase self-scheduled FTRs in the Annual FTR Auction and that revenue is then paid back to the ARR holders, netting the transaction to zero. ARR credits are calculated as the product of the ARR MW (excludes any self-scheduled FTR MW) and the sink-minus-source price difference for the ARR path from the Annual FTR Auction.

47 For Table 8-19 through Table 8-22, aggregates are separated into their individual bus components and each bus is assigned to a control zone. Aggregates that are external sinks are included in the PJM Control Zone.

FTR credits equal FTR target allocations adjusted by the FTR payout ratio. The FTR target allocation is equal to the product of the FTR MW and the congestion price differences between sink and source that occur in the Day-Ahead Energy Market. FTR credits are paid to FTR holders and, depending on market conditions, may be less than the target allocation. The FTR payout ratio equals the percentage of the target allocation that FTR holders actually receive as credits. The FTR payout ratio was 100 percent of the target allocation for the 2006 to 2007 planning period.

The "Congestion" column shows the amount of congestion in each control zone from the Day-Ahead Energy Market and the balancing energy market and includes only the congestion costs incurred by the organizations that hold ARRs or self-scheduled FTRs. The last column shows the difference between the total revenue and the congestion for each ARR control zone sink.

Data shown are for the 2006 to 2007 planning period summed by ARR control zone sink. For example, the table shows that for the 2006 to 2007 planning period, ARRs allocated to the JCPL Control Zone received a total of $48.8 million in revenue which was the sum of $38.5 million in ARR credits and $10.3 million in credits for self-scheduled FTRs. This total revenue was $99.6 million less than the congestion costs of $148.4 million from the Day-Ahead Energy Market and the balancing energy market incurred by organizations in the JCPL Control Zone that held ARRs or self-scheduled FTRs.

Table 8-19 ARR and self-scheduled FTR congestion hedging by control zone: Planning period 2006 to 2007

Control Zone	ARR Credits	Self-Scheduled FTR Credits	Total Revenue	Congestion	Total Revenue - Congestion Difference	Percent Hedged
AECO	$37,960,325	$2,545,194	$40,505,519	$98,562,187	($58,056,668)	41.1%
AEP	$5,849,312	$1,972,819	$7,822,131	$195,769,926	($187,947,795)	4.0%
AP	$66,054,626	$560,001,705	$626,056,331	$306,893,885	$319,162,446	204.0%
BGE	$60,435,545	$3,949,724	$64,385,269	$72,164,905	($7,779,636)	89.2%
ComEd	$5,586,175	$19,654,286	$25,240,461	$38,177,869	($12,937,408)	66.1%
DAY	$2,050,472	$45,910	$2,096,382	$10,600,806	($8,504,424)	19.8%
DLCO	$2,157,721	$9,469	$2,167,190	$7,185,829	($5,018,639)	30.2%
Dominion	$38,516,691	$15,528,297	$54,044,988	$891,430,187	($837,385,199)	6.1%
DPL	$19,230,662	$7,073,286	$26,303,948	$94,773,192	($68,469,244)	27.8%
JCPL	$38,456,684	$10,348,818	$48,805,502	$148,371,543	($99,566,041)	32.9%
Met-Ed	$5,822,196	$39,098,770	$44,920,966	$74,507,634	($29,586,668)	60.3%
PECO	$11,326,155	$73,368,203	$84,694,358	($41,674,855)	$126,369,213	>100%
PENELEC	$13,454,376	$32,296,616	$45,750,992	$99,627,192	($53,876,200)	45.9%
Pepco	$41,376,839	$3,380,679	$44,757,518	$311,422,014	($266,664,496)	14.4%
PJM	$4,173,240	$2,655,850	$6,829,090	($52,528)	$6,881,618	>100%
PPL	$4,090,906	$47,202,269	$51,293,175	($19,251,625)	$70,544,800	>100%
PSEG	$118,913,460	$12,244,774	$131,158,234	$76,759,705	$54,398,529	170.9%
RECO	$1,443,947	$0	$1,443,947	$12,331,680	($10,887,733)	11.7%
Total	$476,899,332	$831,376,669	$1,308,276,001	$2,377,599,546	($1,069,323,545)	55.0%

During the 2006 to 2007 planning period, congestion costs associated with the 67,568 MW of allocated ARRs were $2,377.6 million. As Table 8-4 indicates, 38,301 MW of ARRs were converted into FTRs through the self-scheduling option, with 29,267 MW remaining as ARRs. The 29,267 MW of remaining ARRs provided $476.9 million of ARR credits, representing a hedge of 20 percent of the $2,377.6 million in congestion costs incurred, while the self-scheduled FTRs provided $831.4 million of revenue, hedging an additional 35 percent of congestion costs. Total congestion hedged by both was $1,308.3 million, or 55.0 percent. (See Table 8-19.) The effectiveness of ARRs as a hedge depends both on the ARR value which is a function of the FTR auction prices, on congestion patterns in the Day-Ahead and Real-Time Energy Markets and on the FTR payout ratio.

Effectiveness of FTRs as a Hedge against Congestion

FTRs provide a direct hedge against congestion costs. Table 8-20 compares the total FTR credits and the total FTR auction revenues that sink in each control zone and the congestion costs in each control zone for the 2006 to 2007 planning period. FTRs that sink at an aggregate or a bus are assigned to a control zone if applicable. The “FTR Credits” column represents the total FTR target allocations for FTRs that sink in each control zone from the Annual FTR Auction, the Monthly Balance of Planning Period FTR Auctions and any FTRs that were self-scheduled from ARRs, adjusted by the FTR payout ratio. The FTR target allocation is equal to the product of the FTR MW and the congestion price differences between sink and source that occur in the Day-Ahead Energy Market. FTR credits are the product of the FTR target allocations and the FTR payout ratio. The FTR payout ratio was 100 percent of the target allocation for the 2006 to 2007 planning period. The “FTR Auction Revenue” column shows the amount paid for FTRs that sink in each control zone in the Annual FTR Auction, the Monthly Balance of Planning Period FTR Auctions and any self-scheduled FTRs. The FTR hedge is the difference between the FTR credits and the FTR auction revenue. The “Congestion” column shows the total amount of congestion in the Day-Ahead Energy Market and the balancing energy market in each control zone. The last column shows the difference between the FTR hedge and the congestion for each control zone.

All FTRs provided a hedge of $290.1 million against $1,722.8 million in congestion costs incurred.[48] This demonstrates that all FTRs provided a 16.8 percent hedge against congestion costs in PJM. For example, the table shows that for the 2006 to 2007 planning period, all FTRs sunk in the Pepco Control Zone received a total of $141.8 million in FTR credits while these FTRs cost $132.3 million in the FTR auctions. This gives a total FTR hedge of $9.5 million against $201.2 million in congestion costs from the Day-Ahead Energy Market and the balancing energy market. This shows a deficit of $191.7 million in their total FTR hedge position versus the cost of congestion in the Day-Ahead Energy Market and the balancing energy market. It would not be expected that the value of the FTR hedge calculated in this manner would cover all congestion costs as both ARRs and FTRs are available to hedge total congestion. That comparison is provided in Table 8-21.

48 The congestion costs in Table 8-20, Table 8-21 and Table 8-22 (2006 to 2007 planning period) do not equal the congestion costs in Table 8-19 because the congestion costs for organizations that did not hold ARRs had negative congestion costs that lowered the total congestion costs compared to those of just the ARR holders.

Table 8-20 FTR congestion hedging by control zone: Planning period 2006 to 2007

Control Zone	FTR Credits	FTR Auction Revenue	FTR Hedge	Congestion	FTR Hedge - Congestion Difference	Percent Hedged
AECO	$42,768,075	$60,230,082	($17,462,007)	$67,085,194	($84,547,201)	< 0%
AEP	$164,687,852	($35,943,010)	$200,630,862	$166,314,810	$34,316,052	120.6%
AP	$569,068,207	$572,185,631	($3,117,424)	$420,202,812	($423,320,236)	< 0%
BGE	$44,177,535	$44,624,675	($447,140)	$105,375,274	($105,822,414)	< 0%
ComEd	$18,451,540	($9,118,361)	$27,569,901	$135,684,232	($108,114,331)	20.3%
DAY	$2,073,735	($6,460,296)	$8,534,031	$11,743,208	($3,209,177)	72.7%
DLCO	($6,381,093)	($21,902,476)	$15,521,383	$49,965,737	($34,444,354)	31.1%
Dominion	$243,308,757	$44,156,816	$199,151,941	$280,205,524	($81,053,583)	71.1%
DPL	$40,790,763	$44,464,780	($3,674,017)	$99,543,825	($103,217,842)	< 0%
JCPL	$41,450,855	$68,688,063	($27,237,208)	$113,257,858	($140,495,066)	< 0%
Met-Ed	$58,987,745	$50,447,353	$8,540,392	$18,714,551	($10,174,159)	45.6%
PECO	$90,294,949	$128,528,732	($38,233,783)	($55,606,384)	$17,372,601	68.8%
PENELEC	$69,419,846	$79,169,254	($9,749,408)	$120,583,245	($130,332,653)	< 0%
Pepco	$141,801,096	$132,288,429	$9,512,667	$201,191,153	($191,678,486)	4.7%
PJM	$18,234,521	$10,571,744	$7,662,777	($76,889,434)	$84,552,211	< 0%
PPL	$51,180,375	$71,887,428	($20,707,053)	($32,339,599)	$11,632,546	64.0%
PSEG	$131,199,665	$198,188,719	($66,989,054)	$85,602,232	($152,591,286)	< 0%
RECO	$3,309,712	$2,744,571	$565,141	$12,121,505	($11,556,364)	4.7%
Total	$1,724,824,135	$1,434,752,134	$290,072,001	$1,722,755,743	($1,432,683,742)	16.8%

Effectiveness of ARRs and FTRs as a Hedge against Congestion

Table 8-21 compares the revenue for ARR and FTR holders and the congestion in both the Day-Ahead Energy Market and the balancing energy market for the 2006 to 2007 planning period. This compares the total hedge provided by all ARRs and all FTRs to the total congestion costs within each control zone. ARRs and FTRs that sink at an aggregate or a bus are assigned to a control zone if applicable. ARR credits are calculated as the product of the ARR MW and the sink-minus-source price difference for the ARR path from the Annual FTR Auction. The "FTR Credits" column represents the total FTR target allocation for FTRs that sink in each control zone from the Annual FTR Auction, the Monthly Balance of Planning Period FTR Auctions and any FTRs that were self-scheduled from ARRs, adjusted by the FTR payout ratio. The FTR target allocation is equal to the product of the FTR MW and congestion price differences between sink and source that occur in the Day-Ahead Energy Market. FTR credits are the product of the FTR target allocations and the FTR payout ratio. The FTR payout ratio was 100 percent of the target allocation for the 2006 to 2007 planning period. The "FTR Auction Revenue" column shows the amount paid for FTRs that sink in each control zone in the Annual FTR Auction, the Monthly Balance of Planning Period FTR Auctions and any ARRs that were self-scheduled as FTRs. ARR holders that self-schedule FTRs purchased the FTRs in the Annual FTR Auction and that revenue was then paid back to those ARR holders through ARR credits on a monthly basis throughout the planning period, ultimately netting the transaction to zero. The total ARR and FTR hedge is the sum of the ARR credits and the FTR credits minus the FTR auction revenue. The "Congestion" column shows the total amount of congestion in the Day-Ahead Energy Market and the balancing energy market in each control zone. The last column shows the difference between the total ARR and FTR hedge and the congestion cost for each control zone.

The results indicate that the value of ARRs and FTRs together were less than total congestion costs by about $28 million. During the 2006 to 2007 planning period, the 67,568 MW of cleared ARRs produced $1,404.6 million of ARR credits while the total of all FTR credits was $1,724.8 million. Together, the ARR credits and FTR credits provided approximately $3,129.5 million in total ARR and FTR revenue. When calculating the total ARR and FTR hedge, the cost to obtain the FTRs must be subtracted from the total ARR and FTR revenue. This cost is the total sum of the FTR auction revenues which was $1,434.8 million for the 2006 to 2007 planning period. The total ARR and FTR hedge equals $1,694.7 million, a hedge of 98.4 percent of $1,722.8 million of congestion in the Day-Ahead Energy Market and the balancing energy market. For example, the table shows that all ARRs and FTRs that sink in the AP Control Zone received $651.2 million in ARR credits and $569.1 million in FTR credits. After subtracting the cost of the FTRs, the FTR auction revenue of $572.2 million, the total ARR and FTR hedge was $648.1 million. Their total hedge was $227.9 million higher than the $420.2 million of congestion in the Day-Ahead Energy Market and the balancing energy market.

Table 8-21 ARR and FTR congestion hedging by control zone: Planning period 2006 to 2007

Control Zone	ARR Credits	FTR Credits	FTR Auction Revenue	Total ARR and FTR Hedge	Congestion	Total Hedge - Congestion Difference	Percent Hedged
AECO	$41,133,569	$42,768,075	$60,230,082	$23,671,562	$67,085,194	($43,413,632)	35.3%
AEP	$11,313,430	$164,687,852	($35,943,010)	$211,944,292	$166,314,810	$45,629,482	127.4%
AP	$651,180,242	$569,068,207	$572,185,631	$648,062,818	$420,202,812	$227,860,006	154.2%
BGE	$65,120,212	$44,177,535	$44,624,675	$64,673,072	$105,375,274	($40,702,202)	61.4%
ComEd	$8,862,245	$18,451,540	($9,118,361)	$36,432,146	$135,684,232	($99,252,086)	26.9%
DAY	$2,148,066	$2,073,735	($6,460,296)	$10,682,097	$11,743,208	($1,061,111)	91.0%
DLCO	$2,304,673	($6,381,093)	($21,902,476)	$17,826,056	$49,965,737	($32,139,681)	35.7%
Dominion	$60,102,387	$243,308,757	$44,156,816	$259,254,328	$280,205,524	($20,951,196)	92.5%
DPL	$24,817,167	$40,790,763	$44,464,780	$21,143,150	$99,543,825	($78,400,675)	21.2%
JCPL	$52,986,630	$41,450,855	$68,688,063	$25,749,422	$113,257,858	($87,508,436)	22.7%
Met-Ed	$50,448,008	$58,987,745	$50,447,353	$58,988,400	$18,714,551	$40,273,849	315.2%
PECO	$114,251,938	$90,294,949	$128,528,732	$76,018,155	($55,606,384)	$131,624,539	>100 %
PENELEC	$53,844,756	$69,419,846	$79,169,254	$44,095,348	$120,583,245	($76,487,897)	36.6%
Pepco	$44,747,368	$141,801,096	$132,288,429	$54,260,035	$201,191,153	($146,931,118)	27.0%
PJM	$12,103,102	$18,234,521	$10,571,744	$19,765,879	($76,889,434)	$96,655,313	>100 %
PPL	$72,426,920	$51,180,375	$71,887,428	$51,719,867	($32,339,599)	$84,059,466	>100 %
PSEG	$135,412,323	$131,199,665	$198,188,719	$68,423,269	$85,602,232	($17,178,963)	79.9%
RECO	$1,443,947	$3,309,712	$2,744,571	$2,009,088	$12,121,505	($10,112,417)	16.6%
Total	$1,404,646,983	$1,724,824,135	$1,434,752,134	$1,694,718,984	$1,722,755,743	($28,036,759)	98.4%

Table 8-22 shows that for the 2006 to 2007 planning period, the total ARR and FTR hedge was $28 million less than the total congestion within PJM. All ARRs and FTRs hedged approximately 98.4 percent of the total congestion costs in the Day-Ahead Energy Market and the balancing energy market within PJM. For the first seven months of the 2007 to 2008 planning period, all ARRs and FTRs hedged 92.3 percent of the total congestion costs within PJM. The total ARR and FTR hedge position was less than the cost of congestion by $92.7 million.

Table 8-22 ARR and FTR congestion hedging: Planning periods 2006 to 2007 and 2007 to 2008[49]

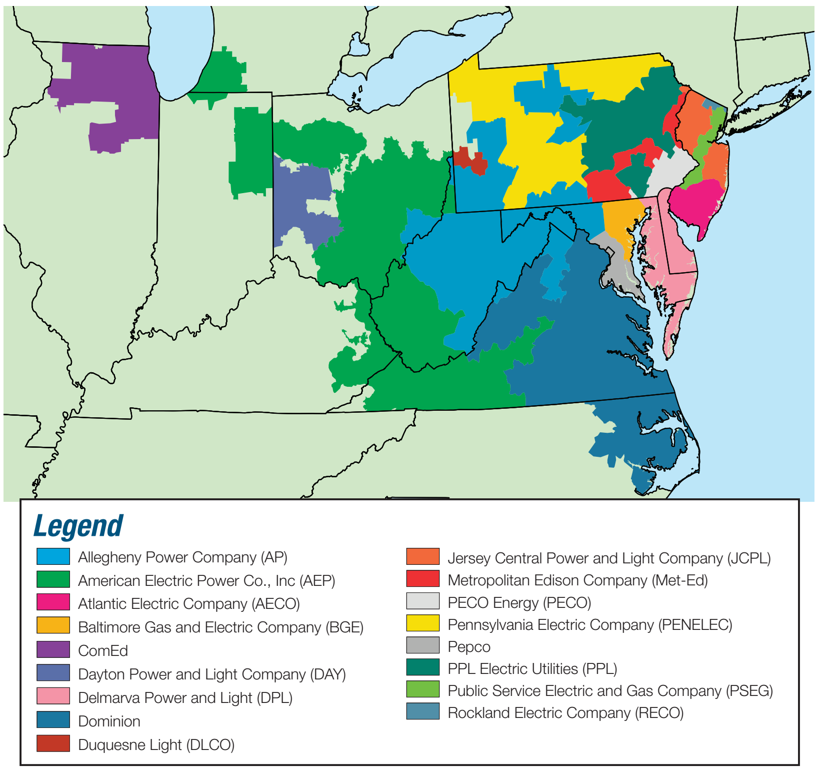
Planning Period	ARR Credits	FTR Credits	FTR Auction Revenue	Total ARR and FTR Hedge	Congestion	Total Hedge - Congestion Difference	Percent Hedged
2006/2007	$1,404,646,983	$1,724,824,135	$1,434,752,134	$1,694,718,984	$1,722,755,743	($28,036,759)	98.4%
2007/2008*	$1,640,453,406	$1,193,886,008	$1,726,169,098	$1,108,170,316	$1,200,838,156	($92,667,840)	92.3%
* Shows seven months ended 31-Dec-07							

49 The FTR credits do not include after-the-fact adjustments.

APPENDIX A – PJM GEOGRAPHY

During 2007, the PJM geographic footprint encompassed 17 control zones located in Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia.

Figure A-1 PJM's footprint and its 17 control zones



Analysis of 2007 market results requires comparison to 2006 and certain other prior years. During 2006 and 2007 the PJM footprint was stable. During calendar years 2004 and 2005, however, PJM integrated five new control zones, three in 2004 and two in 2005. When making comparisons involving this period, the 2004, 2005 and 2006 state of the market reports referenced phases, each corresponding to market integration dates:[1]

- Phase 1 (2004). The four-month period from January 1, through April 30, 2004, during which PJM was comprised of the Mid-Atlantic Region, including its 11 zones,[2] and the Allegheny Power Company (AP) Control Zone.[3]

1 See the *2004 State of the Market Report* (March 8, 2005) for more detailed descriptions of Phases 1, 2 and 3 and the *2005 State of the Market Report* (March 8, 2006) for more detailed descriptions of Phases 4 and 5.

2 The Mid-Atlantic Region is comprised of the AECO, BGE, DPL, JCPL, Met-Ed, PECO, PENELEC, Pepco, PPL, PSEG and RECO control zones.

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

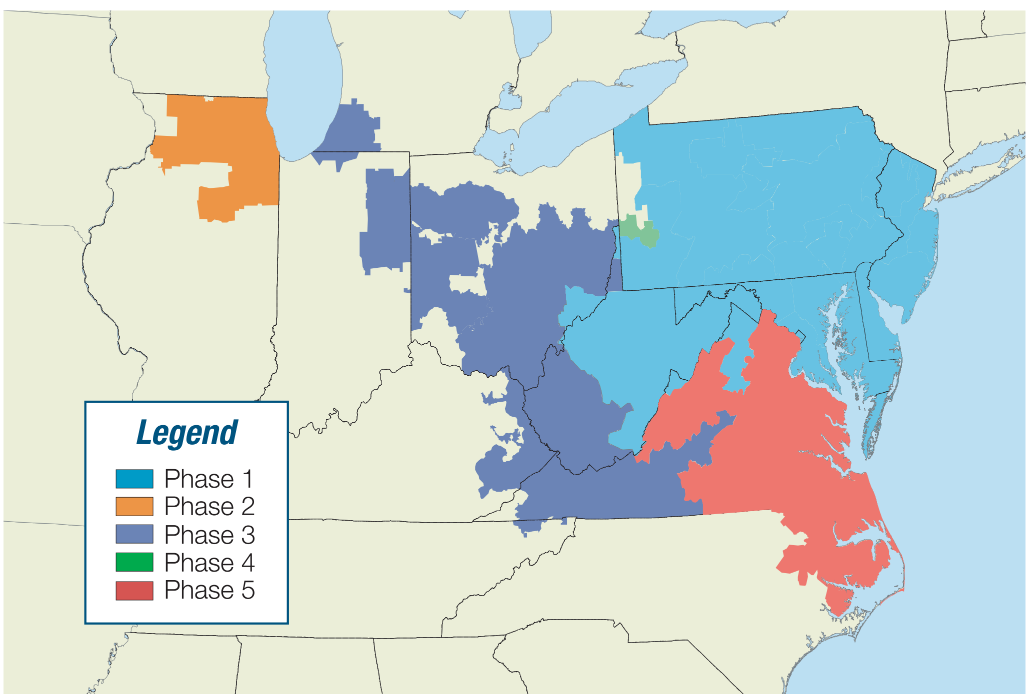
- **Phase 2 (2004).** The five-month period from May 1, through September 30, 2004, during which PJM was comprised of the Mid-Atlantic Region, including its 11 zones, the AP Control Zone and the ComEd Control Area.[4]

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

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

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

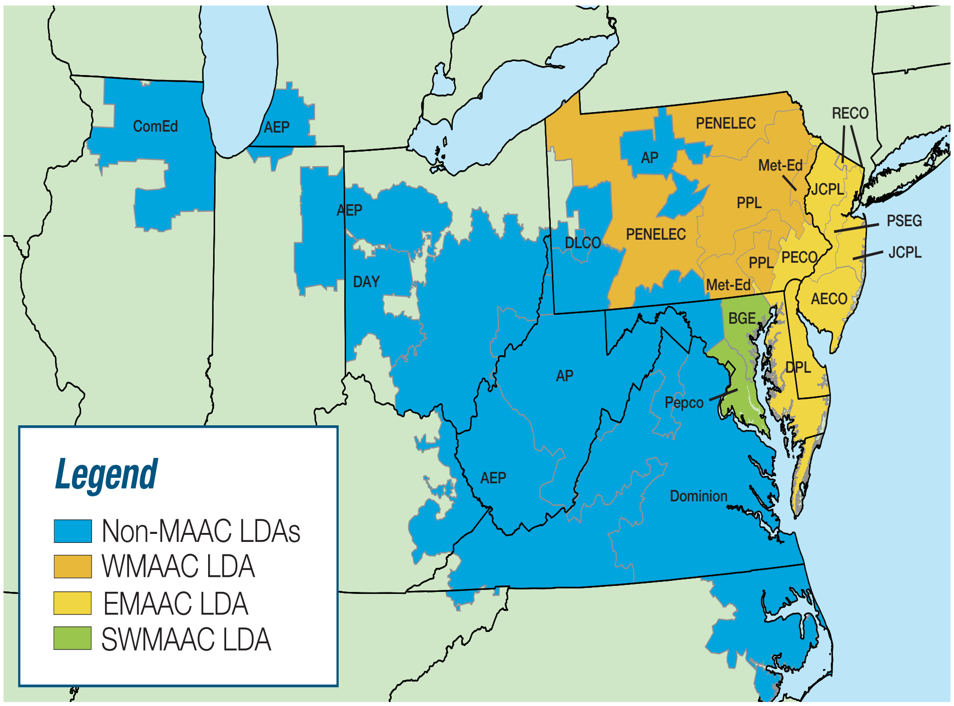
Figure A-2 PJM integration phases



4 During the five-month period May 1, through September 30, 2004, the ComEd Control Zone (ComEd) was called the Northern Illinois Control Area (NICA).

A locational deliverability area (LDA) is a geographic area within the PJM Control Area that has limited transmission capability to import capacity in the RPM design to satisfy its reliability requirements, as determined by PJM in connection with the preparation of the Regional Transmission Expansion Plan (RTEP) and as specified in Schedule 10.1 of the PJM "Reliability Assurance Agreement with Load-Serving Entities."[5]

Figure A-3 PJM locational deliverability areas

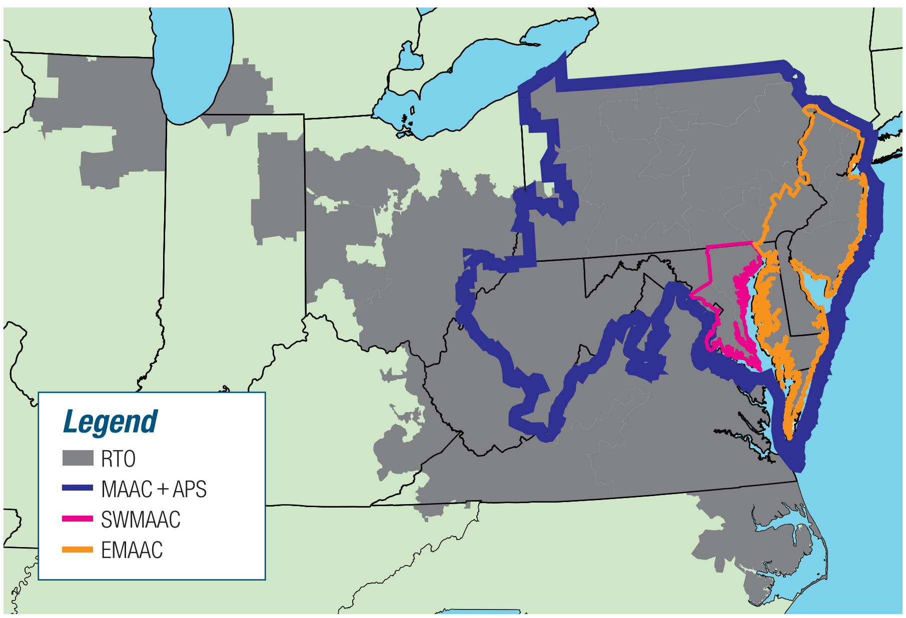


5 See PJM. "Open Access Transmission Tariff (OATT)," "Attachment DD: Definition 2.38" (Issued September 29, 2006, with an effective date of June 1, 2007).

In PJM's Reliability Pricing Model (RPM) Auctions, markets are defined dynamically by LDA. The regional transmission organization (RTO) market comprises the entire PJM footprint, unless an LDA is constrained. Each constrained LDA or group of LDAs is a separate market with a separate clearing price and the RTO market is the balance of the footprint.

For the 2007/2008 and 2008/2009 base auctions, the markets were RTO, EMAAC and SWMAAC. For the 2009/2010 base auction, the markets were RTO, MAAC+APS (Allegheny Power System) and SWMAAC. These RPM Auction markets are shown in Figure A-4.

Figure A-4 PJM RPM locational deliverability area markets



APPENDIX B – PJM MARKET MILESTONES

Year	Month	Event
1996	April	FERC Order 888, "Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities"
1997	April	Energy Market with cost-based offers and market-clearing prices
	November	FERC approval of ISO status for PJM
1998	April	Cost-based Energy LMP Market
1999	January	Daily Capacity Market
	March	FERC approval of market-based rates for PJM
	March	Monthly and Multimonthly Capacity Credit Markets
	March	FERC approval of Market Monitoring Plan
	April	Offer-based Energy LMP Market
	April	FTR Market
2000	June	Regulation Market
	June	Day-Ahead Energy Market
	July	Customer Load-Reduction Pilot Program
2001	June	PJM Emergency and Economic Load-Response Programs
2002	April	Integration of AP Control Zone into PJM Western Region
	June	PJM Emergency and Economic Load-Response Programs
	December	Spinning Reserve Market
	December	FERC approval of RTO status for PJM
2003	May	Annual FTR Auction
2004	May	Integration of ComEd Control Area into PJM
	October	Integration of AEP Control Zone into PJM Western Region
	October	Integration of DAY Control Zone into PJM Western Region
2005	January	Integration of DLCO Control Zone into PJM
	May	Integration of Dominion Control Zone into PJM
2006	May	Balance of Planning Period FTR Auction
2007	April	First RPM Auction
	June	Inclusion of marginal loss component in LMP

APPENDIX C – ENERGY MARKET

This appendix provides more detailed information about load, locational marginal prices (LMP) and offer-capped units.

Load

Frequency Distribution of Load

Table C-1 provides the frequency distributions of PJM load by hour, for the calendar years 2003 to 2007.[1] The table shows the number of hours (frequency) and the cumulative percent of hours (cumulative percent) when the load was between 0 GWh and 20 GWh and then within a given 5-GWh load interval, or for the cumulative column, within the interval plus all the lower load intervals. The integrations of the AP Control Zone during 2002, the ComEd, AEP and DAY control zones during 2004 and the DLCO and Dominion control zones during 2005 mean that annual comparisons of load frequency are significantly affected by PJM's geographic growth.[2]

In 2003, the most frequently occurring load interval was 35 GWh to 40 GWh at 31.3 percent of the hours, while load was less than 35 GWh for 36.3 percent of the hours.

The frequency distribution of load in 2004 reflects the integrations of the ComEd, AEP and DAY control zones. The most frequently occurring load interval was 35 GWh to 40 GWh at 15.8 percent of the hours. The next most frequently occurring interval was 40 GWh to 45 GWh at 14.9 percent of the hours. Load was less than 60 GWh for 74.8 percent of the time, less than 70 GWh for 92.8 percent of the time and less than 90 GWh for all but nine hours.

The frequency distribution of load in 2005 reflects the phased integrations of the DLCO and Dominion control zones. The most frequently occurring load interval was 75 GWh to 80 GWh at 16.1 percent of the hours. The next most frequently occurring interval was 65 GWh to 70 GWh at 13.4 percent of the hours. Load was less than 85 GWh for 72.9 percent of the time, less than 100 GWh for 88.2 percent of the time and less than 130 GWh for all but 22 hours.

For the year 2006, the most frequently occurring load interval was 75 GWh to 80 GWh at 17.1 percent of the hours. The next most frequently occurring interval was 80 GWh to 85 GWh at 15.3 percent of the hours. Load was less than 85 GWh for 70.9 percent of the hours, less than 100 GWh for 91.5 percent of the hours and less than 130 GWh for all but 50 hours.

During 2007, the most frequently occurring load interval was 80 GWh to 85 GWh at 15.3 percent of the hours. The next most frequently occurring interval was 75 GWh to 80 GWh at 14.0 percent of the hours. Load was less than 85 GWh for 62.6 percent of the hours, less than 100 GWh for 88.8 percent of the hours and less than 130 GWh for all but 15 hours.

1 The definitions of load are discussed in the *2007 State of the Market Report*, Volume II, Appendix I, "Load Definitions."

2 See the *2007 State of the Market Report*, Volume II, Appendix A, "PJM Geography."

The peak demand for 2007 was 139,428 MW on August 8, 2007. It was 3.6 percent lower than the 2006 peak demand of 144,644 MW on August 2, 2006.[3]

Table C-1 Frequency distribution of PJM real-time, hourly load: Calendar years 2003 to 2007

	2003		2004		2005		2006		2007	
Load (GWh)	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent
0 to 20	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
20 to 25	100	1.14%	15	0.17%	0	0.00%	0	0.00%	0	0.00%
25 to 30	1,193	14.76%	280	3.36%	0	0.00%	0	0.00%	0	0.00%
30 to 35	1,887	36.30%	697	11.29%	0	0.00%	0	0.00%	0	0.00%
35 to 40	2,738	67.56%	1,387	27.08%	0	0.00%	0	0.00%	0	0.00%
40 to 45	1,666	86.58%	1,311	42.01%	0	0.00%	0	0.00%	0	0.00%
45 to 50	796	95.66%	1,150	55.10%	71	0.81%	2	0.02%	0	0.00%
50 to 55	284	98.90%	847	64.74%	286	4.08%	129	1.50%	79	0.90%
55 to 60	84	99.86%	885	74.82%	636	11.34%	504	7.25%	433	5.84%
60 to 65	12	100.00%	760	83.47%	843	20.96%	689	15.11%	637	13.12%
65 to 70	0	100.00%	821	92.82%	1,170	34.32%	967	26.15%	890	23.28%
70 to 75	0	100.00%	391	97.27%	1,089	46.75%	1,079	38.47%	878	33.30%
75 to 80	0	100.00%	157	99.06%	1,407	62.81%	1,501	55.61%	1,227	47.31%
80 to 85	0	100.00%	48	99.60%	887	72.93%	1,337	70.87%	1,338	62.58%
85 to 90	0	100.00%	26	99.90%	557	79.29%	943	81.63%	981	73.78%
90 to 95	0	100.00%	7	99.98%	453	84.46%	569	88.13%	741	82.24%
95 to 100	0	100.00%	2	100.00%	330	88.23%	295	91.50%	577	88.82%
100 to 105	0	100.00%	0	100.00%	308	91.75%	215	93.95%	382	93.18%
105 to 110	0	100.00%	0	100.00%	283	94.98%	161	95.79%	223	95.73%
110 to 115	0	100.00%	0	100.00%	169	96.91%	145	97.44%	179	97.77%
115 to 120	0	100.00%	0	100.00%	113	98.20%	102	98.61%	106	98.98%
120 to 125	0	100.00%	0	100.00%	93	99.26%	45	99.12%	43	99.47%
125 to 130	0	100.00%	0	100.00%	43	99.75%	27	99.43%	31	99.83%
130 to 135	0	100.00%	0	100.00%	22	100.00%	19	99.65%	12	99.97%
135 to 140	0	100.00%	0	100.00%	0	100.00%	19	99.86%	3	100.00%
> 140	0	100.00%	0	100.00%	0	100.00%	12	100.00%	0	100.00%

Off-Peak and On-Peak Load

Table C-2 presents summary load statistics for 1998 to 2007 for the off-peak and on-peak hours, while Table C-3 shows the percent change in load on a year-to-year basis. The on-peak period is defined for each weekday (Monday to Friday) as the hour ending 0800 to the hour ending 2300 Eastern Prevailing Time (EPT), excluding North American Electric Reliability Council (NERC) holidays. Table C-2 shows that on-peak

3 Peak-load data for 2007 are from PJM's eMTR data.

load was about 24 percent higher than off-peak load in 2007. Average load during on-peak hours in 2007 was 3.1 percent higher than in 2006. Off-peak load in 2007 was 2.4 percent higher than in 2006.[4] (See Table C-3.)

Table C-2 Off-peak and on-peak load (MW): Calendar years 1998 to 2007

	Average			Median			Standard Deviation		
	Off Peak	On Peak	On Peak/ Off Peak	Off Peak	On Peak	On Peak/ Off Peak	Off Peak	On Peak	On Peak/ Off Peak
1998	25,268	32,344	1.28	24,728	31,081	1.26	4,091	4,388	1.07
1999	26,453	33,269	1.26	25,780	31,950	1.24	4,947	4,824	0.98
2000	26,917	33,797	1.26	26,313	32,757	1.24	4,466	4,181	0.94
2001	26,804	34,303	1.28	26,433	33,076	1.25	4,225	4,851	1.15
2002	31,817	40,362	1.27	30,654	38,378	1.25	6,060	7,419	1.22
2003	33,595	41,755	1.24	32,971	40,802	1.24	5,546	5,424	0.98
2004	44,631	56,020	1.26	43,028	56,578	1.31	10,845	12,595	1.16
2005	70,291	87,164	1.24	68,049	82,503	1.21	12,733	15,236	1.20
2006	71,810	88,323	1.23	70,300	84,810	1.21	11,348	12,662	1.12
2007	73,499	91,066	1.24	71,751	88,494	1.23	11,501	11,926	1.04

Table C-3 Multiyear change in load: Calendar years 1998 to 2007

	Average			Median			Standard Deviation		
	Off Peak	On Peak	On Peak/ Off Peak	Off Peak	On Peak	On Peak/ Off Peak	Off Peak	On Peak	On Peak/ Off Peak
1998	NA	NA	NA	NA	NA	NA	NA	NA	NA
1999	4.7%	2.9%	(1.6%)	4.3%	2.8%	(1.6%)	20.9%	9.9%	(8.4%)
2000	1.8%	1.6%	0.0%	2.1%	2.5%	0.0%	(9.7%)	(13.3%)	(4.1%)
2001	(0.4%)	1.5%	1.6%	0.5%	1.0%	0.8%	(5.4%)	16.0%	22.3%
2002	18.7%	17.7%	(0.8%)	16.0%	16.0%	0.0%	43.4%	52.9%	6.1%
2003	5.6%	3.5%	(2.4%)	7.6%	6.3%	(0.8%)	(8.5%)	(26.9%)	(19.7%)
2004	32.9%	34.2%	1.6%	30.5%	38.7%	5.6%	95.5%	132.2%	18.4%
2005	57.5%	55.6%	(1.6%)	58.2%	45.8%	(7.6%)	17.4%	21.0%	3.4%
2006	2.2%	1.3%	(0.8%)	3.3%	2.8%	0.0%	(10.9%)	(16.9%)	(6.7%)
2007	2.4%	3.1%	0.8%	2.1%	4.3%	1.7%	1.3%	(5.8%)	(7.1%)

4 The increase in on-peak median load for 2006 was incorrectly reported as 3.2 percent in the *2006 State of the Market Report* rather than the 2.8 percent shown here.

Locational Marginal Price (LMP)

In assessing changes in LMP over time, the PJM Market Monitoring Unit (MMU) examines three measures: simple average LMP, load-weighted LMP and fuel-cost-adjusted, load-weighted LMP. Simple average LMP measures the change in reported price. Load-weighted LMP measures the change in reported price weighted by the actual hourly MWh load to reflect what customers actually pay for energy. Fuel-cost-adjusted, load-weighted LMP measures the change in reported price actually paid by load after accounting for the change in price that reflects shifts in underlying fuel prices.[5]

Real-Time LMP

Frequency Distribution of Real-Time LMP

Table C-4 provides frequency distributions of PJM real-time hourly LMP for the calendar years 2003 to 2007. The table shows the number of hours (frequency) and the cumulative percent of hours (cumulative percent) when the hourly PJM LMP was within a given $10-per-MWh price interval and lower than $300 per MWh, or within a given $100-per-MWh price interval and higher than $300 per MWh, or for the cumulative column, within the interval plus all the lower price intervals.

In 2003, LMP was most frequently in the $10-per-MWh to $20-per-MWh interval. In 2004, however, LMP occurred in the $30-per-MWh to $40-per-MWh interval most frequently at 21.9 percent of the time and in the $20-per-MWh to $30-per-MWh interval nearly as frequently at 21.6 percent of the time. In 2005, LMP occurred in the $30-per-MWh to $40-per-MWh interval most frequently at 20.5 percent of the time and in the $20-per-MWh to $30-per-MWh interval at 14.7 percent of the time. In 2005, LMP was less than $60 per MWh for 63.2 percent of the hours, less than $100 per MWh for 87.4 percent of the hours and LMP was $200 per MWh or greater for 35 hours (0.4 percent of the hours). In 2006, LMP was in the $20-per-MWh to $30-per-MWh interval most frequently (22.4 percent of the time) and in the $30-per-MWh to $40-per-MWh interval next most frequently (21.0 percent of the hours). In 2007, LMP was in the $20-per-MWh to $30-per-MWh interval most frequently (17.9 percent of the time) and in the $30-per-MWh to $40-per-MWh interval next most frequently (16.8 percent of the hours). In 2007, LMP was $60 per MWh or less for 60.7 percent of the hours and was $100 per MWh or less for 91.0 percent of the hours. LMP was more than $200 per MWh for 35 hours (0.4 percent of the hours).

5 See the *2007 State of the Market Report*, Volume II, Appendix H, "Calculating Locational Marginal Price."

Table C-4 Frequency distribution by hours of PJM Real-Time Energy Market LMP (Dollars per MWh): Calendar years 2003 to 2007

	2003		2004		2005		2006		2007	
LMP	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent
$10 and less	241	2.75%	173	1.97%	142	1.62%	85	0.97%	56	0.64%
$10 to $20	2,083	26.53%	712	10.08%	259	4.58%	247	3.79%	185	2.75%
$20 to $30	1,957	48.87%	1,900	31.71%	1,290	19.30%	1,958	26.14%	1,571	20.68%
$30 to $40	1,102	61.45%	1,928	53.65%	1,793	39.77%	1,840	47.15%	1,470	37.47%
$40 to $50	1,043	73.36%	1,445	70.10%	1,172	53.15%	1,405	63.18%	1,108	50.11%
$50 to $60	812	82.63%	994	81.42%	877	63.16%	1,040	75.06%	931	60.74%
$60 to $70	532	88.70%	668	89.03%	730	71.50%	662	82.61%	827	70.18%
$70 to $80	380	93.04%	445	94.09%	568	77.98%	479	88.08%	726	78.47%
$80 to $90	255	95.95%	270	97.17%	453	83.15%	347	92.04%	646	85.84%
$90 to $100	152	97.68%	117	98.50%	374	87.42%	230	94.67%	451	90.99%
$100 to $110	75	98.54%	72	99.32%	297	90.81%	162	96.52%	240	93.73%
$110 to $120	52	99.13%	25	99.60%	208	93.18%	95	97.60%	178	95.76%
$120 to $130	28	99.45%	14	99.76%	159	95.00%	61	98.30%	110	97.02%
$130 to $140	23	99.71%	10	99.87%	110	96.26%	46	98.82%	76	97.89%
$140 to $150	14	99.87%	6	99.94%	94	97.33%	27	99.13%	53	98.49%
$150 to $160	5	99.93%	3	99.98%	53	97.93%	16	99.32%	26	98.79%
$160 to $170	1	99.94%	1	99.99%	57	98.58%	11	99.44%	29	99.12%
$170 to $180	1	99.95%	0	99.99%	51	99.17%	6	99.51%	18	99.33%
$180 to $190	2	99.98%	1	100.00%	22	99.42%	3	99.54%	9	99.43%
$190 to $200	1	99.99%	0	100.00%	16	99.60%	5	99.60%	15	99.60%
$200 to $210	0	99.99%	0	100.00%	12	99.74%	3	99.63%	6	99.67%
$210 to $220	1	100.00%	0	100.00%	10	99.85%	7	99.71%	4	99.71%
$220 to $230	0	100.00%	0	100.00%	5	99.91%	1	99.73%	4	99.76%
$230 to $240	0	100.00%	0	100.00%	1	99.92%	1	99.74%	2	99.78%
$240 to $250	0	100.00%	0	100.00%	1	99.93%	1	99.75%	5	99.84%
$250 to $260	0	100.00%	0	100.00%	3	99.97%	1	99.76%	2	99.86%
$260 to $270	0	100.00%	0	100.00%	2	99.99%	0	99.76%	4	99.91%
$270 to $280	0	100.00%	0	100.00%	0	99.99%	3	99.79%	0	99.91%
$280 to $290	0	100.00%	0	100.00%	1	100.00%	1	99.81%	0	99.91%
$290 to $300	0	100.00%	0	100.00%	0	100.00%	0	99.81%	0	99.91%
$300 to $400	0	100.00%	0	100.00%	0	100.00%	11	99.93%	2	99.93%
$400 to $500	0	100.00%	0	100.00%	0	100.00%	2	99.95%	4	99.98%
$500 to $600	0	100.00%	0	100.00%	0	100.00%	1	99.97%	1	99.99%
$600 to $700	0	100.00%	0	100.00%	0	100.00%	1	99.98%	1	100.00%
> $700	0	100.00%	0	100.00%	0	100.00%	2	100.00%	0	100.00%

Off-Peak and On-Peak, PJM Real-Time, Load-Weighted LMP: 2006 to 2007

Table C-5 shows load-weighted, average LMP for 2006 and 2007 during off-peak and on-peak periods. In 2007, the on-peak, load-weighted LMP was 53 percent higher than the off-peak LMP, while in 2006, it was 55 percent higher. On-peak, load-weighted, average LMP in 2007 was 14.7 percent higher than in 2006. Off-peak, load-weighted LMP in 2007 was 16.6 percent higher than in 2006. The on-peak median LMP was higher in 2007 than in 2006 by 26.4 percent; off-peak median LMP was higher in 2007 than in 2006 by 12.8 percent. Dispersion in load-weighted LMP, as indicated by standard deviation, was 21.5 percent higher in 2007 than in 2006 during off-peak hours and was 12.1 percent lower during on-peak hours. Since the average was above the median during on-peak and off-peak hours, both showed a positive skewness. The average was, however, proportionately higher than the median in 2007 as compared to 2006 during off-peak periods (27.8 percent in 2007 compared to 23.6 percent in 2006). The differences reflect larger positive skewness in the off-peak hours.

Table C-5 Off-peak and on-peak, PJM load-weighted, average LMP (Dollars per MWh): Calendar years 2006 to 2007

	2006			2007			Difference 2006 to 2007		
	Off Peak	On Peak	On Peak/ Off Peak	Off Peak	On Peak	On Peak/ Off Peak	Off Peak	On Peak	On Peak/ Off Peak
Average	$41.53	$64.46	1.55	$48.43	$73.91	1.53	16.6%	14.7%	(1.3%)
Median	$33.59	$53.96	1.61	$37.89	$68.23	1.80	12.8%	26.4%	11.8%
Standard deviation	$24.03	$44.45	1.85	$29.20	$39.07	1.34	21.5%	(12.1%)	(27.6%)

Off-Peak and On-Peak, Real-Time, Fuel-Cost-Adjusted, Load-Weighted, Average LMP

In a competitive market, changes in LMP result from changes in demand and changes in supply. As competitive offers are equivalent to the marginal cost of generation and fuel costs make up about 80 percent of marginal cost on average for marginal units, fuel cost is a key factor affecting supply and, therefore, the competitive clearing price. In a competitive market, if fuel costs increase and nothing else changes, the competitive price also increases.

The impact of fuel cost on LMP depends on the fuel burned by the marginal units. To account for differences in fuel cost between different time periods of interest, the fuel-cost-adjusted, load-weighted LMP is used to compare load-weighted LMPs on a common fuel-cost basis.[6]

Table C-6 and Table C-7 show the real-time, load-weighted, average LMP and the real-time, fuel-cost-adjusted, load-weighted, average LMP for 2007 for on-peak and off-peak hours. During on-peak hours, the real-time, fuel-cost-adjusted, load-weighted, average LMP in 2007 increased by 16.1 percent over the real-time, load-weighted LMP in 2006. The real-time, fuel-cost-adjusted, load-weighted LMP in 2007 increased by 20.9 percent in the off-peak hours compared to the real-time, load-weighted LMP in 2006.

6 See the *2007 State of the Market Report*, Volume II, Appendix K, "Calculation and Use of Generator Sensitivity/Unit Participation Factors."

Table C-6 On-peak PJM fuel-cost-adjusted, load-weighted, average LMP (Dollars per MWh): Year-over-year method

	2005	2006	2007
Load-weighted LMP	$78.04	$64.46	$73.91
Fuel-cost-adjusted, load-weighted LMP	NA	$72.37	$74.86
Year-over-year comparison	NA	(7.3%)	16.1%

Table C-7 Off-peak PJM fuel-cost-adjusted, load-weighted, average LMP (Dollars per MWh): Year-over-year method

	2005	2006	2007
Load-weighted LMP	$47.69	$41.53	$48.43
Fuel-cost-adjusted, load-weighted LMP	NA	$46.05	$50.20
Year-over-year comparison	NA	(3.4%)	20.9%

PJM Real-Time, Load-Weighted LMP during Constrained Hours

Table C-8 shows that the PJM load-weighted, average LMP during constrained hours was 12.0 percent higher in 2007 than it had been in 2006.[7] The load-weighted, median LMP during constrained hours was 18.9 percent higher in 2007 than in 2006 and the standard deviation was 4.8 percent lower in 2007 than in 2006.

Table C-8 PJM load-weighted, average LMP during constrained hours (Dollars per MWh): Calendar years 2006 to 2007

	2006	2007	Difference
Average	$57.62	$64.54	12.0%
Median	$48.34	$57.49	18.9%
Standard deviation	$40.01	$38.09	(4.8%)

Table C-9 provides a comparison of PJM load-weighted, average LMP during constrained and unconstrained hours for 2006 and 2007. In 2007, load-weighted, average LMP during constrained hours was 35.0 percent higher than load-weighted, average LMP during unconstrained hours. The comparable number for 2006 was 61.1 percent.

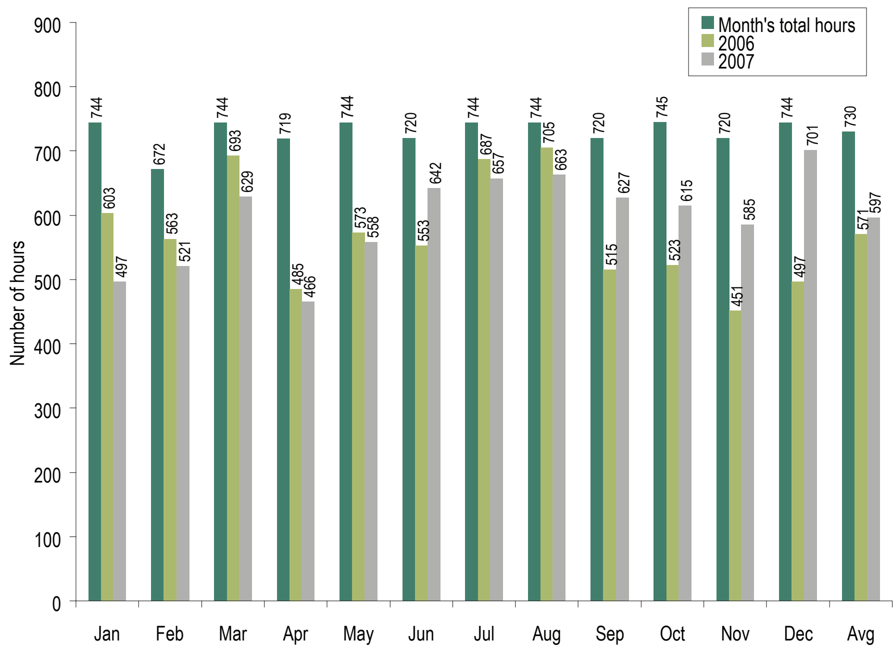
Table C-9 PJM load-weighted, average LMP during constrained and unconstrained hours (Dollars per MWh): Calendar years 2006 to 2007

	2006			2007		
	Unconstrained Hours	Constrained Hours	Difference	Unconstrained Hours	Constrained Hours	Difference
Average	$35.76	$57.62	61.1%	$47.82	$64.54	35.0%
Median	$29.67	$48.34	62.9%	$40.15	$57.49	43.2%
Standard deviation	$18.43	$40.01	117.1%	$26.78	$38.09	42.2%

7 A constrained hour, or a constraint hour, is any hour during which one or more facilities are congested. Since 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 has been measured using the convention that an hour is constrained if any of its component five-minute intervals is constrained. This is also consistent with the way in which PJM reports real-time congestion. In the *2005 State of the Market Report*, an hour was considered constrained if one or more facilities were constrained for four or more of the 12 five-minute intervals in that hour. In the *2004 State of the Market Report*, this appendix defined a congested hour as one in which the difference in LMP between at least two buses in that hour was greater than $1.00.

Figure C-1 shows the number of hours and the number of constrained hours during each month in 2006 and 2007. There were 7,161 constrained hours in 2007 and 6,848 in 2006, an increase of approximately 4.6 percent. Figure C-1 also shows that the average number of constrained hours per month was slightly higher in 2007 than in 2006, with 597 per month in 2007 versus 571 per month in 2006.

Figure C-1 PJM real-time constrained hours: Calendar years 2006 to 2007



Day-Ahead and Real-Time LMP

On average, prices in the Real-Time Energy Market in 2007 were higher than those in the Day-Ahead Energy Market and real-time prices showed greater dispersion. This pattern of system average LMP distribution for 2007 can be seen by comparing Table C-4 and Table C-10. Together they show the frequency distribution by hours for the two markets. In PJM's Real-Time Energy Market, the most frequently occurring price interval was the $20-per-MWh to $30-per-MWh interval with 17.9 percent of the hours in 2007. (See Table C-4.) The most frequently occurring price interval in the PJM Day-Ahead Energy Market was the $30-per-MWh to $40-per-MWh interval with 17.1 percent of the hours in 2007. (See Table C-10.) In the Real-Time Energy Market, prices were above $200 per MWh for 35 hours (0.4 percent of the hours), reaching a high for the year of $673.98 per MWh on August 8, 2007, during the hour ending 1700 EPT. In the Day-Ahead Energy Market, prices were above $200 per MWh for one hour (0.0 percent of the hours) and reached a high for the year of $200.50 per MWh on August 8, 2007, during the hour ending 1700 EPT.

Table C-10 Frequency distribution by hours of PJM Day-Ahead Energy Market LMP (Dollars per MWh): Calendar years 2003 to 2007

	2003		2004		2005		2006		2007	
LMP	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent
$10 and less	131	1.50%	59	0.67%	47	0.54%	11	0.13%	3	0.03%
$10 to $20	1,530	18.96%	715	8.81%	162	2.39%	147	1.80%	88	1.04%
$20 to $30	1,846	40.03%	1,684	27.98%	1,022	14.05%	1,610	20.18%	1,291	15.78%
$30 to $40	1,635	58.70%	1,848	49.02%	1,753	34.06%	1,747	40.13%	1,495	32.84%
$40 to $50	1,384	74.50%	1,946	71.17%	1,382	49.84%	1,890	61.70%	1,221	46.78%
$50 to $60	1,004	85.96%	1,357	86.62%	1,102	62.42%	1,364	77.27%	1,266	61.23%
$60 to $70	554	92.28%	728	94.91%	812	71.69%	905	87.60%	1,301	76.08%
$70 to $80	318	95.91%	278	98.08%	686	79.52%	524	93.58%	939	86.80%
$80 to $90	157	97.71%	110	99.33%	524	85.50%	237	96.29%	504	92.56%
$90 to $100	95	98.79%	42	99.81%	388	89.93%	145	97.95%	264	95.57%
$100 to $110	41	99.26%	11	99.93%	263	92.93%	65	98.69%	155	97.34%
$110 to $120	21	99.50%	4	99.98%	207	95.30%	38	99.12%	104	98.53%
$120 to $130	22	99.75%	2	100.00%	151	97.02%	11	99.25%	59	99.20%
$130 to $140	7	99.83%	0	100.00%	102	98.18%	8	99.34%	33	99.58%
$140 to $150	5	99.89%	0	100.00%	64	98.92%	8	99.43%	13	99.73%
$150 to $160	10	100.00%	0	100.00%	46	99.44%	7	99.51%	8	99.82%
$160 to $170	0	100.00%	0	100.00%	27	99.75%	6	99.58%	7	99.90%
$170 to $180	0	100.00%	0	100.00%	11	99.87%	6	99.65%	3	99.93%
$180 to $190	0	100.00%	0	100.00%	8	99.97%	3	99.68%	4	99.98%
$190 to $200	0	100.00%	0	100.00%	1	99.98%	3	99.71%	1	99.99%
$200 to $210	0	100.00%	0	100.00%	2	100.00%	3	99.75%	1	100.00%
$210 to $220	0	100.00%	0	100.00%	0	100.00%	3	99.78%	0	100.00%
$220 to $230	0	100.00%	0	100.00%	0	100.00%	1	99.79%	0	100.00%
$230 to $240	0	100.00%	0	100.00%	0	100.00%	3	99.83%	0	100.00%
$240 to $250	0	100.00%	0	100.00%	0	100.00%	2	99.85%	0	100.00%
$250 to $260	0	100.00%	0	100.00%	0	100.00%	1	99.86%	0	100.00%
$260 to $270	0	100.00%	0	100.00%	0	100.00%	2	99.89%	0	100.00%
$270 to $280	0	100.00%	0	100.00%	0	100.00%	1	99.90%	0	100.00%
$280 to $290	0	100.00%	0	100.00%	0	100.00%	1	99.91%	0	100.00%
$290 to $300	0	100.00%	0	100.00%	0	100.00%	1	99.92%	0	100.00%
>$300	0	100.00%	0	100.00%	0	100.00%	7	100.00%	0	100.00%

Off-Peak and On-Peak, Day-Ahead and Real-Time, Simple Average LMP

Table C-11 shows PJM simple average LMP during off-peak and on-peak periods for the Day-Ahead and Real-Time Energy Markets during calendar year 2007. On-peak, day-ahead and real-time, average LMPs were 63 percent and 57 percent higher, respectively, than the corresponding off-peak average LMPs. Since the average was above the median in these markets, both showed a positive skewness. The average was, however, proportionately higher than the median in the Real-Time Energy Market as compared to the Day-Ahead Energy Market during both on-peak and off-peak periods (8 percent and 28 percent compared to 4 percent and 14 percent, respectively). The differences reflect larger positive skewness in the Real-Time Energy Market.

Figure C-2 and Figure C-3 show the difference between real-time and day-ahead LMP during calendar year 2007 during the on-peak and off-peak hours, respectively. The difference between real-time and day-ahead average LMP during on-peak hours was $2.54 per MWh. (Day-ahead LMP was lower than real-time LMP.) During the off-peak hours, the difference between real-time and day-ahead average LMP was $3.22 per MWh. (Day-ahead LMP was lower than real-time LMP.)

Table C-11 Off-peak and on-peak, simple average LMP (Dollars per MWh): Calendar year 2007

	Day Ahead			Real Time			Difference in Real Time Relative to Day Ahead		
	Off Peak	On Peak	On Peak/ Off Peak	Off Peak	On Peak	On Peak/ Off Peak	Off Peak	On Peak	On Peak/ Off Peak
Average	$42.33	$68.84	1.63	$45.55	$71.38	1.57	7.6%	3.7%	(3.7%)
Median	$37.10	$66.08	1.78	$35.50	$65.88	1.86	(4.3%)	(0.3%)	4.5%
Standard deviation	$18.21	$21.91	1.20	$27.65	$36.57	1.32	51.8%	66.9%	10.0%

Figure C-2 Hourly real-time LMP minus day-ahead LMP (On-peak hours): Calendar year 2007

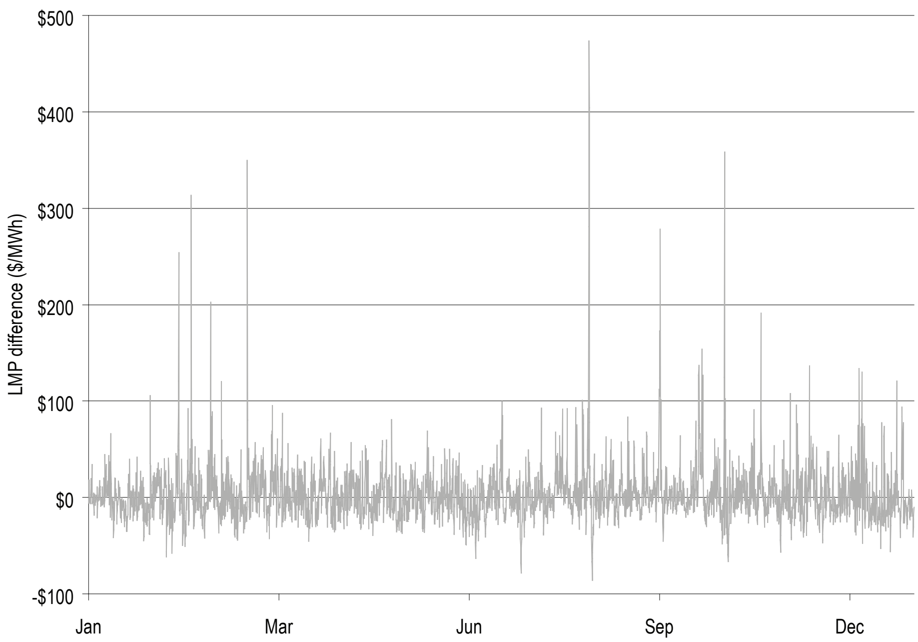
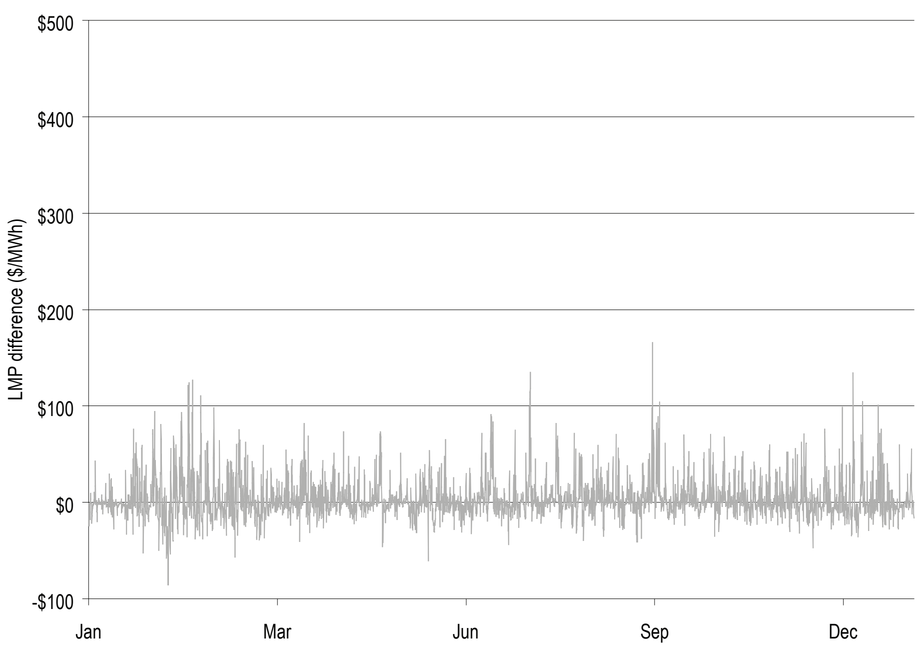


Figure C-3 Hourly real-time LMP minus day-ahead LMP (Off-peak hours): Calendar year 2007



On-Peak and Off-Peak, Zonal, Day-Ahead and Real-Time, Simple Average LMP

Table C-12 and Table C-13 show the on-peak and off-peak, simple average LMPs for each zone in the Day-Ahead and Real-Time Energy Markets during calendar year 2007. The zone with the maximum difference between on-peak real-time and day-ahead LMP was the BGE Control Zone with a day-ahead, on-peak, zonal LMP that was $4.20 lower than its real-time, on-peak, zonal LMP. The ComEd Control Zone had the smallest difference with its real-time, on-peak, zonal LMP $0.15 lower than its day-ahead, on-peak, zonal LMP. (See Table C-12.) The BGE Control Zone had the largest difference between off-peak zonal, real-time and day-ahead LMP, with day-ahead LMP that was $4.61 lower than real-time LMP. The zone with the smallest difference between off-peak, zonal, real-time and day-ahead LMP was the ComEd Control Zone with a day-ahead LMP that was $0.81 lower than real-time LMP. (See Table C-13.)

Table C-12 On-peak, zonal, simple average LMP (Dollars per MWh): Calendar year 2007

	Day Ahead	Real Time	Difference	Difference as Percent Real Time
AECO	$78.04	$79.85	$1.81	2.27%
AEP	$59.45	$60.01	$0.56	0.93%
AP	$68.95	$71.22	$2.27	3.19%
BGE	$80.18	$84.38	$4.20	4.98%
ComEd	$59.55	$59.40	($0.15)	(0.25%)
DAY	$59.11	$60.00	$0.89	1.48%
DLCO	$57.04	$59.05	$2.01	3.40%
Dominion	$76.66	$79.08	$2.42	3.06%
DPL	$76.17	$78.11	$1.94	2.48%
JCPL	$78.54	$80.42	$1.88	2.34%
Met-Ed	$76.43	$79.43	$3.00	3.78%
PECO	$75.22	$75.90	$0.68	0.90%
PENELEC	$66.54	$68.54	$2.00	2.92%
Pepco	$81.03	$84.29	$3.26	3.87%
PPL	$74.03	$75.67	$1.64	2.17%
PSEG	$79.41	$81.11	$1.70	2.10%
RECO	$78.83	$80.49	$1.66	2.06%

Table C-13 Off-peak, zonal, simple average LMP (Dollars per MWh): Calendar year 2007

	Day Ahead	Real Time	Difference	Difference as Percent Real Time
AECO	$49.80	$52.09	$2.29	4.40%
AEP	$33.42	$34.81	$1.39	3.99%
AP	$42.61	$45.45	$2.84	6.25%
BGE	$52.47	$57.08	$4.61	8.08%
ComEd	$32.97	$33.78	$0.81	2.40%
DAY	$33.25	$34.68	$1.43	4.12%
DLCO	$32.16	$30.75	($1.41)	(4.59%)
Dominion	$51.88	$55.99	$4.11	7.34%
DPL	$49.56	$51.97	$2.41	4.64%
JCPL	$49.79	$52.94	$3.15	5.95%
Met-Ed	$48.70	$51.62	$2.92	5.66%
PECO	$49.06	$51.01	$1.95	3.82%
PENELEC	$41.13	$42.82	$1.69	3.95%
Pepco	$53.72	$58.16	$4.44	7.63%
PPL	$47.77	$50.12	$2.35	4.69%
PSEG	$50.45	$52.67	$2.22	4.21%
RECO	$49.89	$51.20	$1.31	2.56%

PJM Day-Ahead and Real-Time, Simple Average LMP during Constrained Hours

Figure C-4 shows the number of constrained hours for the Day-Ahead and Real-Time Energy Markets, and the total number of hours in each month for 2007. Overall, there were 7,161 constrained hours in the Real-Time Energy Market and 8,757 constrained hours in the Day-Ahead Energy Market. Figure C-4 shows that in every month of calendar year 2007 the number of constrained hours in the Day-Ahead Energy Market exceeded those in the Real-Time Energy Market. Over the year, the Day-Ahead Energy Market had 22.3 percent more constrained hours than the Real-Time Energy Market.

Figure C-4 PJM day-ahead and real-time, market-constrained hours: Calendar year 2007

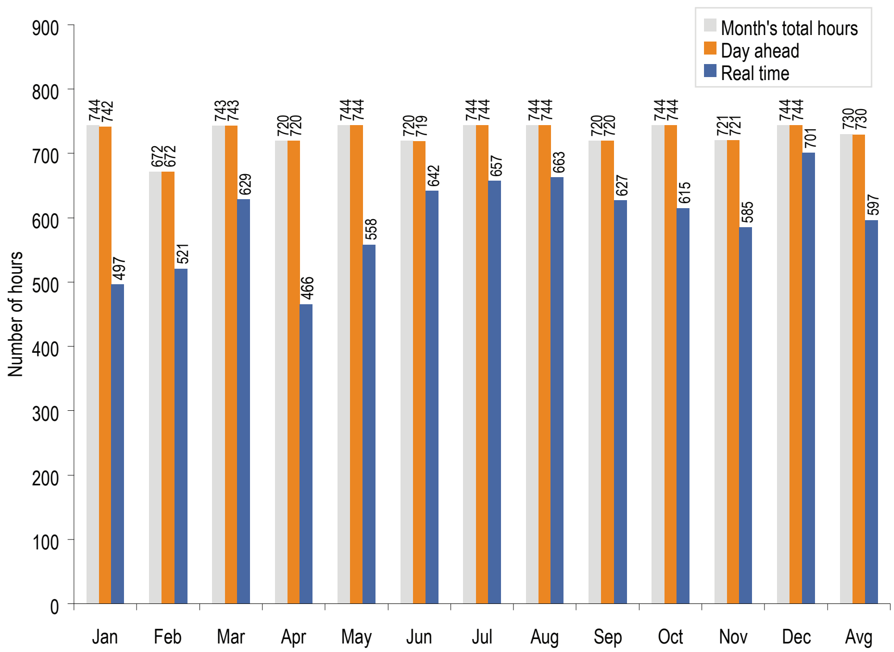


Table C-14 shows PJM simple average LMP during constrained and unconstrained hours in the Day-Ahead and Real-Time Energy Markets. In the Day-Ahead Energy Market, average LMP during constrained hours was 7.9 percent higher than average LMP during unconstrained hours.[8] In the Real-Time Energy Market, average LMP during constrained hours was 33.2 percent higher than average LMP during unconstrained hours. Average LMP during constrained hours was 10.3 percent higher in the Real-Time Energy Market than in the Day-Ahead Energy Market and LMP during unconstrained hours was 10.7 percent lower in the Real-Time Energy Market than in the Day-Ahead Energy Market.

8 This comparison is of limited usefulness as there were only three, day-ahead unconstrained hours.

Table C-14 PJM simple average LMP during constrained and unconstrained hours (Dollars per MWh): Calendar year 2007

	Day Ahead			Real Time		
	Unconstrained Hours	Constrained Hours	Difference	Unconstrained Hours	Constrained Hours	Difference
Average	$50.68	$54.68	7.9%	$45.28	$60.32	33.2%
Median	$64.50	$52.34	(18.9%)	$37.02	$52.49	41.8%
Standard deviation	$25.49	$23.99	(5.9%)	$25.82	$35.70	38.3%

Taken together, the data show that average LMP in the Day-Ahead Energy Market during constrained hours was $0.01 (0.0 percent) higher than the overall average LMP for the Day-Ahead Energy Market, while average LMP during unconstrained hours was $3.99 (7.3 percent) lower although these comparisons are of limited usefulness as there were only three unconstrained hours in the Day-Ahead Energy Market.[9] In the Real-Time Energy Market, average LMP during constrained hours was 4.8 percent higher than the overall average LMP for the Real-Time Energy Market, while average LMP during unconstrained hours was 21.4 percent lower.

Offer-Capped Units

PJM's market power mitigation goals have focused on market designs that promote competition and that limit market power mitigation to situations where market structure is not competitive and thus where market design alone cannot mitigate market power. In the PJM Energy Market, this situation occurs primarily in the case of local market power. Offer capping occurs only as a result of structurally noncompetitive local markets and noncompetitive offers in the Day-Ahead and Real-Time Energy Markets.

PJM has clear rules limiting the exercise of local market power.[10] The rules provide for offer capping when conditions on the transmission system create a structurally noncompetitive local market, when units in that local market have made noncompetitive offers and when such offers would set the price above the competitive level in the absence of mitigation. Offer caps are set at the level of a competitive offer. Offer-capped units receive the higher of the market price or their offer cap. Thus, if broader market conditions lead to a price greater than the offer cap, the unit receives the higher market price. The rules governing the exercise of local market power recognize that units in certain areas of the system would be in a position to extract monopoly profits, but for these rules. The offer-capping rules exempt certain units from offer capping based on the date of their construction. Such exempt units can and do exercise market power, at times, that would not be permitted if the units were not exempt.

Under existing rules, PJM suspends offer capping when structural market conditions, as determined by the three pivotal supplier test, indicate that suppliers are reasonably likely to behave in a competitive manner.[11] The goal is to apply a clear rule to limit the exercise of market power by generation owners in load pockets, but to apply the rule in a flexible manner in real time and to lift offer capping when the exercise of market power is unlikely based on the real-time application of the market structure screen.

9 See the *2007 State of the Market Report*, Volume II, Section 2, "Energy Market, Part 1" for a discussion of load and LMP.

10 See PJM. "Amended and Restated Operating Agreement (OA)," Schedule 1, Section 6.4.2 (January 19, 2007).

11 See the *2007 State of the Market Report*, Volume II, Appendix L, "Three Pivotal Supplier Test."

Levels of offer capping have generally been low and stable over the last five years. Table C-15 through Table C-18 show offer capping by month, including the number of offer-capped units and the level of offer-capped MW in the Day-Ahead and Real-Time Energy Markets.[12]

Table C-15 Average day-ahead, offer-capped units: Calendar years 2003 to 2007

	2003		2004		2005		2006		2007	
	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent
Jan	0.5	0.1%	0.4	0.1%	0.4	0.0%	0.1	0.0%	0.2	0.0%
Feb	0.7	0.1%	0.2	0.0%	0.4	0.0%	0.2	0.0%	0.8	0.1%
Mar	0.1	0.0%	0.2	0.0%	0.6	0.1%	0.7	0.1%	0.9	0.1%
Apr	0.6	0.1%	0.3	0.0%	0.4	0.0%	0.2	0.0%	0.2	0.0%
May	0.3	0.0%	0.6	0.1%	0.2	0.0%	0.1	0.0%	0.2	0.0%
Jun	0.7	0.1%	1.1	0.2%	0.4	0.0%	0.7	0.1%	0.8	0.1%
Jul	1.4	0.3%	2.6	0.4%	0.9	0.1%	4.1	0.4%	0.6	0.1%
Aug	2.1	0.4%	3.0	0.4%	1.1	0.1%	4.7	0.5%	1.0	0.1%
Sep	1.1	0.2%	3.1	0.4%	0.2	0.0%	0.6	0.1%	0.2	0.0%
Oct	0.9	0.2%	0.6	0.1%	0.3	0.0%	0.3	0.0%	0.8	0.1%
Nov	0.2	0.0%	0.5	0.1%	0.2	0.0%	0.3	0.0%	0.0	0.0%
Dec	0.1	0.0%	0.5	0.1%	0.7	0.1%	0.7	0.0%	0.1	0.0%

Table C-16 Average day-ahead, offer-capped MW: Calendar years 2003 to 2007

	2003		2004		2005		2006		2007	
	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent
Jan	37	0.1%	51	0.1%	87	0.1%	4	0.0%	23	0.0%
Feb	27	0.1%	68	0.1%	75	0.1%	6	0.0%	57	0.1%
Mar	4	0.0%	48	0.1%	58	0.1%	51	0.1%	86	0.1%
Apr	38	0.1%	41	0.1%	34	0.0%	31	0.0%	11	0.0%
May	52	0.1%	52	0.1%	14	0.0%	22	0.0%	38	0.0%
Jun	69	0.2%	49	0.1%	28	0.0%	164	0.2%	28	0.0%
Jul	132	0.3%	243	0.4%	52	0.0%	518	0.5%	45	0.0%
Aug	148	0.3%	348	0.5%	63	0.1%	398	0.4%	58	0.1%
Sep	139	0.3%	221	0.4%	13	0.0%	51	0.1%	14	0.0%
Oct	100	0.2%	34	0.0%	16	0.0%	27	0.0%	77	0.1%
Nov	21	0.1%	28	0.0%	26	0.0%	15	0.0%	4	0.0%
Dec	25	0.1%	35	0.0%	48	0.0%	40	0.0%	4	0.0%

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

Table C-17 Average real-time, offer-capped units: Calendar years 2003 to 2007

	2003		2004		2005		2006		2007	
	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent
Jan	1.5	0.3%	2.7	0.4%	2.5	0.3%	1.9	0.2%	1.2	0.1%
Feb	1.5	0.3%	0.7	0.1%	1.3	0.1%	2.1	0.2%	4.2	0.4%
Mar	0.5	0.1%	0.8	0.1%	1.4	0.2%	2.3	0.2%	1.9	0.2%
Apr	0.8	0.1%	1.8	0.3%	1.2	0.1%	1.5	0.2%	1.3	0.1%
May	1.6	0.3%	5.9	0.8%	0.8	0.1%	3.4	0.3%	1.9	0.2%
Jun	2.9	0.5%	3.9	0.5%	10.0	1.0%	2.5	0.3%	6.0	0.6%
Jul	3.3	0.6%	4.7	0.7%	13.9	1.4%	8.6	0.9%	4.4	0.4%
Aug	6.3	1.1%	6.3	0.9%	13.7	1.4%	9.5	1.0%	9.6	0.9%
Sep	3.7	0.7%	4.2	0.6%	7.9	0.8%	1.8	0.2%	5.5	0.5%
Oct	1.8	0.3%	1.1	0.1%	7.9	0.8%	1.7	0.2%	5.0	0.5%
Nov	1.0	0.2%	1.1	0.1%	3.3	0.3%	1.1	0.1%	2.9	0.3%
Dec	0.8	0.1%	3.3	0.4%	4.4	0.4%	1.0	0.0%	4.7	0.5%

Table C-18 Average real-time, offer-capped MW: Calendar years 2003 to 2007

	2003		2004		2005		2006		2007	
	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent
Jan	86.8	0.2%	175.0	0.4%	208.9	0.3%	42.1	0.1%	50.0	0.1%
Feb	74.2	0.2%	86.8	0.2%	144.9	0.2%	67.1	0.1%	125.0	0.1%
Mar	44.0	0.1%	76.2	0.2%	74.2	0.1%	87.6	0.1%	142.3	0.2%
Apr	28.8	0.1%	115.2	0.3%	58.8	0.1%	75.3	0.1%	48.4	0.1%
May	101.2	0.3%	257.1	0.5%	77.9	0.1%	135.6	0.2%	67.7	0.1%
Jun	110.0	0.3%	166.8	0.3%	652.1	0.7%	160.1	0.2%	190.4	0.2%
Jul	251.6	0.6%	331.9	0.6%	818.8	0.9%	505.8	0.5%	160.0	0.2%
Aug	293.9	0.7%	450.4	0.8%	908.4	1.0%	517.8	0.6%	314.0	0.3%
Sep	240.8	0.7%	268.5	0.5%	476.9	0.6%	68.7	0.1%	218.3	0.3%
Oct	96.0	0.3%	77.2	0.1%	337.5	0.5%	49.4	0.1%	153.2	0.2%
Nov	53.5	0.2%	110.4	0.2%	129.4	0.2%	30.5	0.0%	104.2	0.1%
Dec	44.0	0.1%	202.0	0.3%	155.5	0.2%	11.5	0.0%	146.3	0.2%

In order to help understand the frequency of offer capping in more detail, Table C-19 through Table C-22 show the number of generating units that met the specified criteria for total offer-capped run hours and percentage of offer-capped run hours for the years 2003 through 2006.

Table C-19 Offer-capped unit statistics: Calendar year 2003

	2003 Offer-Capped Hours					
Run Hours Offer-Capped, Percent Greater Than Or Equal To:	Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
90%	0	0	0	0	0	1
80% and < 90%	0	1	0	0	1	7
75% and < 80%	1	0	0	3	3	2
70% and < 75%	0	0	0	1	1	2
60% and < 70%	0	0	0	2	3	11
50% and < 60%	0	0	0	3	2	8
25% and < 50%	4	3	2	0	3	34
10% and < 25%	1	0	0	2	11	38

Table C-20 Offer-capped unit statistics: Calendar year 2004

	2004 Offer-Capped Hours					
Run Hours Offer-Capped, Percent Greater Than Or Equal To:	Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
90%	0	1	1	5	3	5
80% and < 90%	3	0	0	5	6	10
75% and < 80%	1	0	4	0	1	7
70% and < 75%	0	1	0	0	1	7
60% and < 70%	1	1	0	0	0	7
50% and < 60%	0	0	0	1	1	13
25% and < 50%	1	1	1	3	6	32
10% and < 25%	2	0	2	3	16	38

Table C-21 Offer-capped unit statistics: Calendar year 2005[13]

Run Hours Offer-Capped, Percent Greater Than Or Equal To:	2005 Offer-Capped Hours					
	Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
90%	12	1	0	1	2	2
80% and < 90%	7	6	0	6	7	10
75% and < 80%	0	1	3	3	8	3
70% and < 75%	0	0	1	2	4	4
60% and < 70%	1	0	3	2	8	9
50% and < 60%	0	0	2	0	2	10
25% and < 50%	2	9	1	3	10	49
10% and < 25%	0	0	1	0	6	33

Table C-22 Offer-capped unit statistics: Calendar year 2006

Run Hours Offer-Capped, Percent Greater Than Or Equal To:	2006 Offer-Capped Hours					
	Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
90%	3	0	0	1	2	0
80% and < 90%	1	5	1	4	3	7
75% and < 80%	0	1	0	2	6	10
70% and < 75%	0	0	0	2	6	18
60% and < 70%	0	1	1	3	5	27
50% and < 60%	0	2	0	0	0	12
25% and < 50%	0	2	1	2	1	31
10% and < 25%	0	0	0	3	9	41

13 Data quality improvements have caused values in this table to vary slightly from previously published results for 2005.

APPENDIX D – INTERCHANGE TRANSACTIONS

In competitive wholesale power markets, market participants' decisions to buy and sell power are based on actual and expected prices. If contiguous wholesale power markets incorporate security-constrained nodal pricing, well-designed interface pricing provides economic signals for import and export decisions by market participants, although those signals may be attenuated by a variety of institutional arrangements.

NYISO Issues

If interface prices were defined and established in a comparable manner by PJM and the New York Independent System Operator (NYISO), if identical rules governed external transactions in PJM and NYISO, if time lags were not built into the rules governing such transactions and if no risks were associated with such transactions, then prices at the interfaces would be expected to be very close and the level of transactions would be expected to be related to any price differentials. The fact that none of these conditions exists is relevant in considering the observed relationship between interface prices and inter-ISO power flows, and those price differentials.

There are institutional differences between PJM and NYISO markets that are relevant to observed differences in border prices.[1] NYISO requires hourly bids or offer prices for each export or import transaction and clears its market for each hour based on hourly bids.[2] Import transactions to NYISO are treated by NYISO as generator bids at the NYISO/PJM proxy bus. Export transactions are treated by NYISO as price-capped load offers. Competing bids and offers are evaluated along with other NYISO resources and a proxy bus price is derived. Bidders are notified of the outcome. This process is repeated, with new bids and offers each hour. A significant lag exists between the time when offers and bids are submitted to NYISO and the time when participants are notified that they have cleared. The lag is a result of the functioning of the real-time commitment (RTC) system and the fact that transactions can only be scheduled at the beginning of the hour.

As a result of NYISO's RTC timing, market participants must submit bids or offers by no less than 75 minutes before the operating hour. The bid or offer includes the MW volume desired and, for imports into NYISO, the asking price or, for exports out of NYISO, the price the participants are willing to pay. The required lead time means that participants make price and MW bids or offers based on expected prices. Transactions are accepted only for a single hour.

Under PJM operating practices, market participants must make a request to import or export power at one of PJM's interfaces at least 20 minutes before the desired start which can be any quarter hour.[3] The duration of the requested transaction can vary from 15 minutes to an unlimited amount of time. Generally, PJM market participants provide only the MW, the duration and the direction of the real-time transaction. While bid prices for transactions are allowed in PJM, only about 1 percent of all transactions submit an associated

1 See the *2005 State of the Market Report* (March 8, 2006), pp. 195-198.

2 See NYISO. "NYISO Transmission Services Manual," Version 2.0 (February 1, 2005) (Accessed February 28, 2008) <http://www.nyiso.com/public/webdocs/documents/manuals/operations/tran_ser_mnl.pdf> (463 KB).

3 See PJM. "Manual 11: Scheduling Operations" (September 28, 2007) (Accessed February 14, 2008) <http://www.pjm.com/contributions/pjm-manuals/pdf/m11.pdf > (823 KB).

price. Transactions are accepted, with virtually no lag, in order of submission based on whether PJM has the capability to import or export the requested MW. Since they receive the actual real-time price for their scheduled imports or exports, these transactions are price takers in the Real-Time Energy Market. As in NYISO, the required lead time means that participants must make offers to buy or sell MW based on expected prices, but the required lead time is substantially shorter in the PJM market.

NYISO rules provide that RTC results should be available 45 minutes before the operating hour. Thus winning bidders have 25 minutes from the time when RTC results indicate that their transaction will flow to meet PJM's 20-minute notice requirement. To get a transaction cleared with PJM, the market participant must have a valid North American Electric Reliability Council (NERC) Tag, an Open Access Same-Time Information System (OASIS) reservation, a PJM schedule and a PJM ramp reservation. Each of these requirements takes time to process.

The length of required lead times in both markets may be a contributor to the observed relationship between price differentials and flows. Market conditions can change significantly in a relatively short time. The resulting uncertainty could weaken the observed relationship between contemporaneous interface prices and flows.

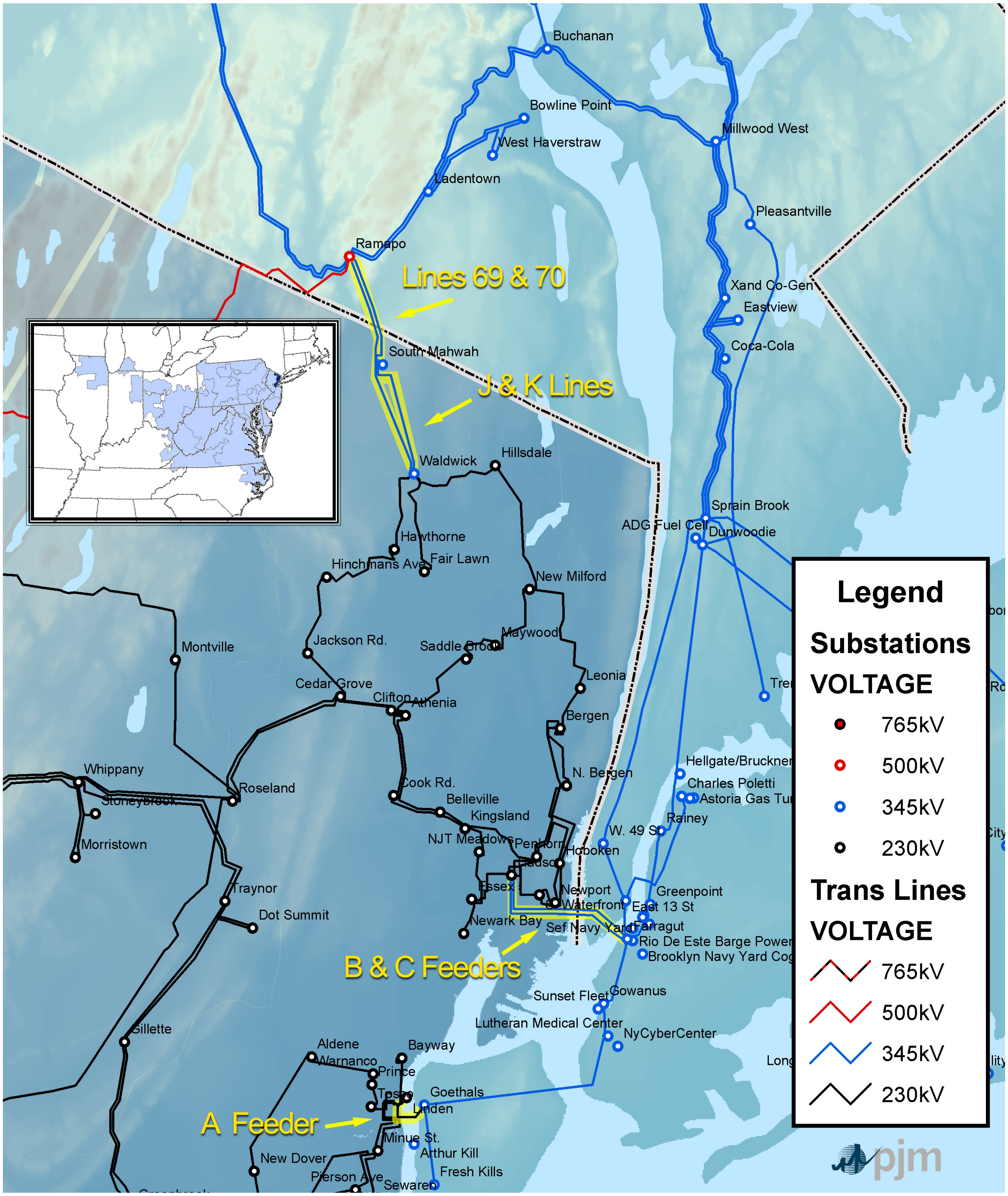
Consolidated Edison Company (Con Edison) and Public Service Electric and Gas Company (PSE&G) Wheeling Contracts

To help meet the demand for power in New York City, Con Edison uses electricity generated in upstate New York and wheeled through New York and New Jersey. A common path is through Westchester County using lines controlled by NYISO. Another path is through northern New Jersey using lines controlled by PJM. The Con Edison/PSE&G contracts governing the New Jersey path evolved during the 1970s and were the subject of a Con Edison complaint to the United States Federal Energy Regulatory Commission (FERC) in 2001. In May 2005, the FERC issued an order setting out a protocol developed by the two companies, PJM and NYISO.[4] In July 2005, the protocol was implemented.

The contracts provide for the delivery of up to 1,000 MW of power from Con Edison's Ramapo Substation in Rockland County, New York, to PSE&G at its Waldwick Switching Substation in Bergen County, New Jersey. PSE&G then wheels the power across its system and delivers it back to Con Edison across lines connecting directly into the city. (See Figure D-1.) Two separate contracts cover these wheeling arrangements. A 1975 agreement covers delivery of up to 400 MW through Ramapo (New York) to PSE&G's Waldwick Switching Station (New Jersey) then to the New Milford Switching Station (New Jersey) via the J line and ultimately from the Linden Switching Station (New Jersey) to the Goethals Substation (New York) and from the Hudson Generating Station (New Jersey) to the Farragut Switching Station (New York), via the A and B feeders, respectively. A 1978 agreement covers delivery of up to an additional 600 MW through Ramapo to Waldwick then to Fair Lawn, via the K line, and ultimately through a second Hudson-to-Farragut line, the C feeder. In 2001, Con Edison alleged that PSE&G had underdelivered on the agreements and asked the FERC to resolve the issue.

4 111 FERC ¶ 61,228 (2005).

Figure D-1 Con Edison and PSE&G wheel



Initial Implementation of the FERC Protocol

In May 2005, the FERC issued an order setting out a protocol developed by the four parties.[5] The protocol was implemented in July 2005.

The Day-Ahead Energy Market Process

The protocol allows Con Edison to elect up to the contracted flow under each contract through the PJM Day-Ahead Energy Market. These elections are transactions in the PJM Day-Ahead Energy Market. The 600 MW contract is for firm service and the 400 MW contract has a priority higher than non-firm service but less than firm service. These elections obligate PSE&G to pay congestion charges associated with the daily elected level of service under the 600 MW contract and obligate Con Edison to pay congestion charges associated with the daily elected level of service under the 400 MW contract. The interface prices for this transaction are not defined PJM interface prices, but are defined in the protocol based on the actual facilities governed by the protocol.

Under the protocol, PSE&G is assigned FTRs associated with the 600 MW contract. The PSE&G FTRs are treated like all other FTRs. In 2007, PSE&G's FTR credits were equal to its congestion charges. (Credits had been $0.4 million less than charges in 2006.)[6] Under the protocol, Con Edison receives credits for its elections under the 400 MW contract from a pool containing any excess congestion revenue after FTRs are funded. In 2007, Con Edison's congestion credits equaled its day-ahead congestion charges. However, Con Edison had substantial negative day-ahead congestion charges with the result that Con Edison's total credits exceeded its congestion charges by approximately $1.7 million. (Credits had been $0.7 million less than charges in 2006.) Table D-1 shows the monthly details for both PSE&G and Con Edison. The protocol states:

> If there is congestion in PJM that affects the portion of the wheel that is associated with the 400 MW contract, PJM shall re-dispatch for the portion of the 400 MW contract for which ConEd specified it was willing to pay congestion, and ConEd shall pay for the re-dispatch. ConEd will be credited back for any congestion charges paid in the hour to the extent of any excess congestion revenues collected by PJM that remain after congestion credits are paid to all other firm transmission customers. Such credits to ConEd shall not exceed congestion payments owed or made by it.[7]

In effect, Con Edison has been given congestion credits that are the equivalent of a class of FTRs covering positive congestion with subordinated rights to revenue. However, Con Edison is not treated as having an FTR when congestion is negative. An FTR holder in that position would pay the negative congestion credits, but Con Edison does not. The protocol's provisions about congestion payments clearly cover congestion charges and offsetting congestion credits, but are not explicit on the treatment of Con Edison's negative congestion credits, which were about $1.7 million in 2007. The parties should address this issue.

5 111 FERC ¶ 61,228 (2005).

6 See the *2006 State of the Market Report*, Volume II, Appendix D, "Interchange Transactions," Table D-1, "Con Edison and PSE&G wheel settlements data: Calendar year 2006" (March 8, 2007), pp. 376-377.

7 PJM Interconnection, L.L.C., Operating Protocol for the Implementation of Commission Opinion No. 476, Docket No. EL02-23-000 (Phase II) (Effective: July 1, 2005), Original Sheet No. 6 < www.pjm.com/documents/downloads/agreements/20050701-attachment-iv-operating-protocol.pdf > (330 KB).

The Real-Time Energy Market Process

Under the terms of the protocol, Con Edison can make a real-time election of its desired flow for each hour in the Real-Time Energy Market. If this election differs from its day-ahead schedule, the company is subject to the resultant charges or credits based on the difference between day-ahead and real-time prices. The real-time election differed from the day-ahead schedule in 13 percent of the hours in 2007.

Table D-1 Con Edison and PSE&G wheel settlements data: Calendar year 2007

		Con Edison			PSE&G		
		Day Ahead	Balancing	Total	Day Ahead	Balancing	Total
January	Congestion charge	($107,716.00)		($107,716.00)	($161,574.00)		($161,574.00)
	Congestion credit			$73,200.00			($161,574.00)
	Previous month(s) adj.						
	Net charge			($180,916.00)			$0.00
February	Congestion charge	($257,886.98)	$1,506.57	($256,380.41)	($373,892.68)		($373,892.68)
	Congestion credit			$86,079.72			($373,892.68)
	Previous month(s) adj.						
	Net charge			($342,460.13)			$0.00
March	Congestion charge	$186,039.36	($1,569.47)	$184,469.89	297,540.00		$297,540.00
	Congestion credit			$197,083.36			$297,540.00
	Previous month(s) adj.						
	Net charge			($12,613.47)			$0.00
April	Congestion charge	$113,935.89	$796.37	$114,732.26	$291,906.00		$291,906.00
	Congestion credit			$127,538.49			$291,906.00
	Previous month(s) adj.						
	Net charge			($12,806.23)			$0.00
May	Congestion charge	$436,372.00	($18,781.50)	$417,590.50	$654,558.00		$654,558.00
	Congestion credit			$448,020.00			$654,558.00
	Previous month(s) adj.			$121,038.35			
	Net charge			($151,467.85)			$0.00
June	Congestion charge	$245,449.00	($23,080.14)	$222,368.86	$370,284.00		$370,284.00
	Congestion credit			$103,771.00			$59,898.00
	Previous month(s) adj.						
	Net charge			$118,597.86			$310,386.00
July	Congestion charge	($24,207.00)		($24,207.00)	($37,824.00)		($37,824.00)
	Congestion credit			$214,876.00			$272,562.00
	Previous month(s) adj.						
	Net charge			($239,083.00)			($310,386.00)

Table D-1 Con Edison and PSE&G wheel settlements data: Calendar year 2007, continued

		Con Edison			PSE&G		
		Day Ahead	Balancing	Total	Day Ahead	Balancing	Total
August	Congestion charge	$142,676.00		$142,676.00	$214,014.00		$214,014.00
	Congestion credit			$167,740.00			$214,014.00
	Previous month(s) adj.						
	Net charge			($25,064.00)			$0.00
September	Congestion charge	$495,152.00	($371,969.39)	$123,182.61	$742,728.00		$742,728.00
	Congestion credit			$528,576.00			$742,728.00
	Previous month(s) adj.						
	Net charge			($405,393.39)			$0.00
October	Congestion charge	$144,010.00	($48,307.49)	$95,702.51	$221,568.00		$221,568.00
	Congestion credit			$145,441.10			$221,568.00
	Previous month(s) adj.						
	Net charge			($49,738.59)			$0.00
November	Congestion charge	$137,172.43	($2,160.32)	$135,012.11	$219,164.68		$219,164.68
	Congestion credit			$147,303.34			$219,164.68
	Previous month(s) adj.						
	Net charge			($12,291.23)			$0.00
December	Congestion charge	($265,350.18)		($265,350.18)	($398,025.02)		($398,025.02)
	Congestion credit			$81,113.13			($398,025.02)
	Previous month(s) adj.			($1,353.36)			($479.36)
	Net charge			($345,109.95)			$479.36
Total	Congestion charge	$1,245,646.52	($463,565.37)	$782,081.15	$2,040,446.98	$0.00	$2,040,446.98
	Congestion credit			$2,320,742.14			$2,040,446.98
	Adj.			$119,684.99			($479.36)
	Net charge			($1,658,345.98)			$479.36

APPENDIX E – CAPACITY MARKET

Background

PJM and its members have long relied on capacity obligations as one of the methods to ensure reliability. Under the Reliability Assurance Agreement (RAA) governing the Capacity Market operated by the PJM regional transmission organization (RTO), each load-serving entity (LSE) must own or purchase capacity resources greater than, or equal to, its capacity obligation.

On June 1, 2007, the Reliability Pricing Model (RPM) Capacity Market design was implemented in the PJM Control Area, replacing the Capacity Credit Market (CCM) Capacity Market design. This appendix explains certain key features of the RPM design in more detail.[1]

Demand

VRR Curves

Under RPM, PJM established variable resource requirement (VRR) curves for the PJM RTO and for each constrained locational deliverability area (LDA). The VRR curve is a demand curve based on three price-quantity points. The demand curve quantities are based on negative and positive adjustments to the reliability requirement. The demand curve prices are based on multipliers applied to the net cost of new entry (CONE). Net CONE is CONE minus the energy and ancillary service revenue offset (E&AS).[2]

The PJM reliability requirement represents the target level of reserves required to meet PJM reliability standards. It is the RTO peak-load forecast multiplied by the RTO forecast pool requirement (FPR) less the sum of any unforced capacity (UCAP) obligations served by fixed resource requirement (FRR) entities, all measured in UCAP.

Load Obligations

Participation by LSEs in the RPM for load served in PJM control zones is mandatory, except for those LSEs that have elected the FRR alternative.[3] Under RPM, each LSE that serves load in a PJM zone during the delivery year is responsible for paying a locational reliability charge equal to its daily unforced capacity obligation in the zone multiplied by the final zonal capacity price. LSEs may choose to hedge their locational reliability charge obligations by directly offering resources in the base residual auction (BRA) and second incremental auction or by designating self-supplied resources (resources directly owned or resources contracted for through unit-specific bilateral purchases) as self-scheduled to cover their obligation in the base residual auction.

1 This section relies upon the cited PJM manuals where additional detail may be found.

2 See PJM. "Manual 18: PJM Capacity Market," Revision 0 (Effective June 1, 2007), p. 16 <http://www.pjm.com/contributions/pjm-manuals/pdf/m18.pdf> (604 KB).

3 See PJM. "Manual 18: PJM Capacity Market," Revision 0 (Effective June 1, 2007), p. 78 <http://www.pjm.com/contributions/pjm-manuals/pdf/m18.pdf> (604 KB).

Base UCAP Obligations

A base RTO UCAP obligation is determined after the clearing of the BRA and is posted with the BRA results. The base RTO UCAP obligation is equal to the sum of the UCAP obligation satisfied through the BRA plus the forecast RTO interruptible load for reliability (ILR) obligation. Base zonal UCAP obligations are defined for each zone as an allocation of the RTO UCAP obligation based on zonal, peak-load forecasts and zonal ILR obligations. The zonal UCAP obligation is equal to the zonal, weather-normalized summer peak for the summer four years prior to the delivery year multiplied by the base zonal RPM scaling factor and the FPR plus the forecast zonal ILR obligation.

Final UCAP Obligation

The final RTO UCAP obligation is determined after the clearing of the second incremental auction (IA) and is posted with the second IA results. The final RTO UCAP obligation is equal to the sum of the UCAP obligation satisfied through the BRA and the second IA plus the forecast RTO ILR obligation. The final zonal UCAP obligation is equal to the base zonal UCAP obligation plus the RTO UCAP obligation satisfied in the second IA multiplied by the zone's percentage allocation of the obligation satisfied in the second IA.

LSE Daily UCAP Obligation

Obligation peak load is the peak-load value on which LSEs' UCAP obligations are based. The obligation, peak-load allocation for a zone is constant and effective for the entire delivery year. The daily UCAP obligation of an LSE in a zone/area equals the LSE's obligation peak load in the zone/area multiplied by the final zonal RPM scaling factor and the FPR.

Capacity Resources

Capacity resources may consist of generation resources, load management resources and qualifying transmission upgrades, all of which must meet PJM-specific criteria.[4] Generation resources may be located within or outside of PJM, but they must be committed to serving load within PJM and must pass tests regarding the capability of generation to serve load and to deliver energy.

Generation Resources

Generation resources may consist of existing generation, planned generation, and bilateral contracts for unit-specific capacity resources. Existing generation located within or outside PJM is eligible to be offered into RPM Auctions or traded bilaterally if it meets defined requirements.[5] Planned generation that is participating in PJM's Regional Transmission Expansion Planning (RTEP) Process is eligible to be offered into RPM Auctions if it meets defined requirements.

4 See PJM. "Manual 18: PJM Capacity Market," Revision 0 (Effective June 1, 2007), p. 22 <http://www.pjm.com/contributions/pjm-manuals/pdf/m18.pdf> (604 KB).

5 See PJM. "Manual 13: Emergency Operations," Revision 33 (Effective January 1, 2008) <http://www.pjm.com/contributions/pjm-manuals/pdf/m13.pdf> (461 KB).

Load Management Resources

Load management is the ability to reduce load upon request.[6] A load management resource is eligible to be offered as a demand resource (DR) or interruptible load for reliability (ILR). DR is a load resource that is offered into an RPM Auction as capacity and receives the relevant LDA or RTO resource-clearing price. ILR is a load resource that is not offered into the RPM Auction, but receives the final zonal ILR price determined after the close of the second incremental auction. DR and ILR resources must meet defined requirements.

Qualified Transmission Upgrades

A qualifying transmission upgrade may be offered into the BRA to increase import capability into a transmission-constrained LDA. Such transmission upgrades must meet the identified requirements.[7]

Obligations of Capacity Resources

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

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

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

- Deliverability. To qualify as a PJM capacity resource, energy from the generating unit must be deliverable to load in the PJM Control Area. Capacity resources must be deliverable, consistent with a loss of load expectation as specified by the reliability principles and standards, to the total system load, including portion(s) of the system that may have a capacity deficiency.[8] In addition, for external capacity resources used to meet an accounted-for obligation within PJM, capacity and energy must be delivered to the metered, PJM boundaries through firm transmission service.

6 See PJM. "Manual 18: PJM Capacity Market," Revision 0 (Effective June 1, 2007), p. 33 <http://www.pjm.com/contributions/pjm-manuals/pdf/m18.pdf> (604 KB).

7 See PJM. "Manual 18: PJM Capacity Market," Revision 0 (Effective June 1, 2007), p. 35 <http://www.pjm.com/contributions/pjm-manuals/pdf/m18.pdf> (604 KB).

8 Deliverable per PJM. "Reliability Assurance Agreement," Schedule 10 (May 17, 2004), p. 52 <http://www.pjm.com/documents/downloads/agreements/raa.pdf> (344 KB).

- **Generator Outage Reporting Requirement.** Owners of PJM capacity resources are required to submit historical outage data to PJM pursuant to Schedule 12 of the RAA.[9]

CETO/CETL

Since the ability to import energy and capacity into LDAs may be limited by the existing transmission capability, PJM conducts a load deliverability analysis for each LDA.[10] The first step in this process is to determine the transmission import requirement into an LDA, called the capacity emergency transfer objective (CETO). This value, expressed in MW, is the transmission import capability required for each LDA to meet the area reliability criterion of loss of load expectation due to insufficient import capability alone, of one occurrence in 25 years when the LDA is experiencing a localized capacity emergency.

The second step is to determine the transmission import limit for an LDA, called the capacity emergency transfer limit (CETL), which is also expressed in MW. The CETL is the ability of the transmission system to deliver energy into the LDA when it is experiencing the localized capacity emergency used in the CETO calculation.

If CETL is less than CETO, capacity-related transmission constraints may result in locational price differences in the RPM.[11] This will also trigger the planning of transmission upgrades under the RTEP Process.

Generator Performance: NERC OMC Outage Cause Codes

Table E-1 includes a list of the North American Electric Reliability Council (NERC) GADS cause codes deemed outside management control (OMC). PJM does not automatically include cause codes 9200-9299 as outside management control for the purposes of calculating unforced capacity, with the exception of code 9250 under certain conditions.

9 See PJM. "Reliability Assurance Agreement," Schedule 12 (May 17, 2004), p. 57 <http: //www.pjm.com/documents/downloads/agreements/raa.pdf> (344 KB).

10 See PJM. "Manual 14B: Generation and Transmission Interconnection Planning, Attachment E: PJM Deliverability Methods," Revision 10 (March 1, 2007), <http://www.pjm.com/contributions/pjm-manuals/pdf/m14b-redline.pdf >. PJM Manual 14B indicates that all "electrically cohesive load areas" are tested.

11 See PJM. "Manual 18: PJM Capacity Market," Revision 0 (Effective June 1, 2007), p. 12, <http://www.pjm.com/contributions/pjm-manuals/pdf/m18.pdf> (604 KB).

Table E-1 NERC GADS cause codes deemed outside management control[12] (OMC)

Cause Code	Reason for Outage
3600	Switchyard transformers and associated cooling systems - external
3611	Switchyard circuit breakers - external
3612	Switchyard system protection devices - external
3619	Other switchyard equipment - external
3710	Transmission line (connected to powerhouse switchyard to 1st substation)
3720	Transmission equipment at the 1st substation (see code 9300 if applicable)
3730	Transmission equipment beyond the 1st substation (see code 9300 if applicable)
9000	Flood
9010	Fire, not related to a specific component
9020	Lightning
9025	Geomagnetic disturbance
9030	Earthquake
9035	Hurricane
9036	Storms (ice, snow, etc)
9040	Other catastrophe
9130	Lack of fuel (water from rivers or lakes, coal mines, gas lines, etc) where the operator is not in control of contracts, supply lines, or delivery of fuels
9135	Lack of water (hydro)
9150	Labor strikes company-wide problems or strikes outside the company's jurisdiction such as manufacturers (delaying repairs) or transportation (fuel supply) problems.
9250	Low Btu coal
9300	Transmission system problems other than catastrophes (do not include switchyard problems in this category; see codes 3600 to 3629, 3720 to 3730)
9320	Other miscellaneous external problems
9500	Regulatory (nuclear) proceedings and hearings - regulatory agency initiated
9502	Regulatory (nuclear) proceedings and hearings - intervener initiated
9504	Regulatory (environmental) proceedings and hearings - regulatory agency initiated
9506	Regulatory (environmental) proceedings and hearings - intervener initiated
9510	Plant modifications strictly for compliance with new or changed regulatory requirements (scrubbers, cooling towers, etc.)
9590	Miscellaneous regulatory (this code is primarily intended for use with event contribution code 2 to indicate that a regulatory-related factor contributed to the primary cause of the event)

12 See NERC. "Generator Availability Data System Data Reporting Instructions," Appendix K <ftp://ftp.nerc.com/pub/sys/all_updl/gads/dri/apd-k_Outside_Plant_Management_Control.pdf> (161 KB).

APPENDIX F – ANCILLARY SERVICE MARKETS

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

Area Control Error (ACE)

Area control error (ACE) is a real-time metric used by PJM operators to measure the instantaneous MW imbalance between load plus net interchange and generation within PJM.[1] PJM dispatchers seek to ensure grid reliability by balancing ACE. A dispatcher's success in doing so is measured by control performance standard 1 (CPS1) and balancing authority ACE limit (BAAL) performance. These measurements are mandated by the North American Electric Reliability Council (NERC).

In the absence of a severe grid disturbance, the primary tool used by dispatchers to minimize ACE is regulation. Regulation is defined as a variable amount of energy under automatic control which is independent of economic cost signal and is obtainable within five minutes. Regulation contributes to maintaining the balance between load and generation by moving the output of selected generators up and down via an automatic generation control (AGC) signal.[2]

Resources wishing to participate in the Regulation Market must pass certification and submit to random testing. Certification requires that resources be capable of and responsive to AGC. After receiving certification, all participants in the Regulation Market are tested to ensure that regulation capacity is fully available at all times. Testing occurs at times of minimal load fluctuation. During testing, units must respond to a regulation test pattern for 40 minutes and must reach their offered regulation capacity levels, up and down, within five minutes. Units whose monitored response is less than their offered regulation capacity have their regulating capacity reduced by PJM.[3]

Control Performance Standard (CPS) and Balancing Authority ACE Limit (BAAL)

Two control performance standards are established by NERC for evaluating ACE control. One measure is a statistical measure of ACE variability and its relationship to frequency error. The purpose of the new BAAL standard is to maintain interconnection frequency within a predefined frequency profile under all conditions (normal and abnormal), to prevent frequency-related instability, unplanned tripping of load or generation, or uncontrolled separation or cascading outages that adversely impact the reliability of the interconnection.

- CPS1. NERC requires that the first CPS measure provide a measure of the control area's performance. The measure is intended to provide the control area with a frequency-sensitive evaluation of how well it has met its demand requirements. A minimum passing score for CPS1 is 100 percent.[4]

1 "Two additional terms may be included in ACE under certain conditions – time error bias and manual add (a PJM dispatcher term). These provide for automatic inadvertent interchange payback and error compensation, respectively." See PJM. "Manual 12: Balancing Operations," Revision 16 (November 1, 2007), Section 3, "System Control," p. 12.

2 Regulation Market business rules are defined in PJM. "Manual 11: Scheduling Operations," Revision 32 (September 28, 2007), pp. 33-38.

3 See PJM. "Manual 12: Balancing Operations," Revision 16 (November 1, 2007), Section 4, pp. 47-51.

4 For more information about the definition and calculation of CPS, see PJM. "Manual 12: Balancing Operations," Revision 16 (November 1, 2007), pp. 14-17. The formal definition of CPS1 can be found in NERC's "Performance Standards Reference Document," Version 2 (November 21, 2002), Section B.1.1.1. The formal definition of CPS2 can be found in NERC's "Performance Standards Reference Document," Version 2 (November 21, 2002), Section B.1.1.2.

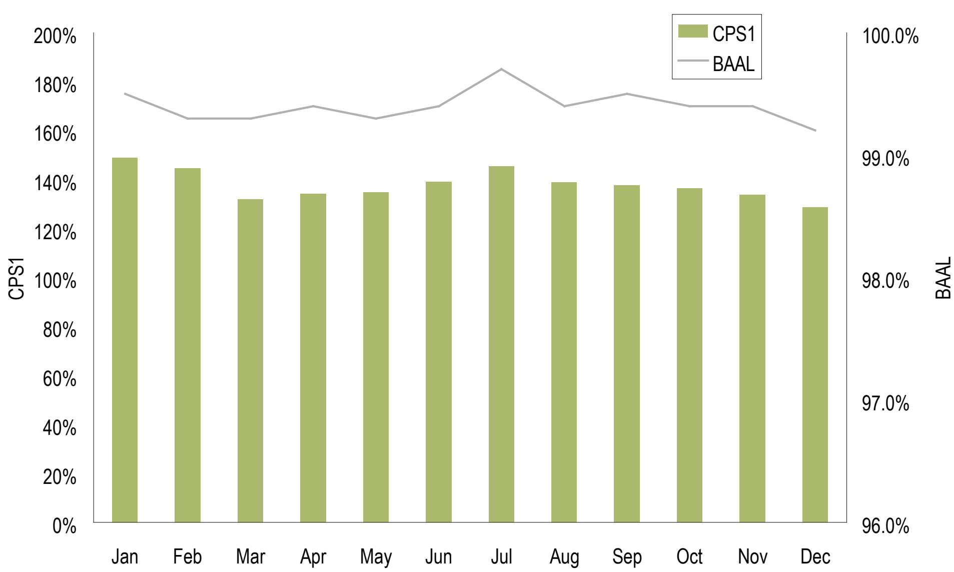
- CPS2. NERC also requires that the second CPS measure provide a measure of 10-minute ACE averages. CPS2 provides a control measure of excessive, unscheduled power flows that could result from large ACEs. CPS2 is measured by counting the number of 10-minute periods during a month when the 10-minute average of the PJM Control Area's ACE is within defined limits known as L10. The specific, 10-minute periods of each hour are those ending at 10, 20, 30, 40, 50 and 60 minutes after the hour. A passing score for CPS2 is achieved when 90 percent of these 10-minute periods during a single month are within L10. From January 1, through January 31, 2007, the PJM Control Area's L10 standard was 284.3 MW. From February 1, through December 31, 2007, PJM's L10 standard was 286.1 MW.

- BAAL. Since August 1, 2005, PJM has participated in the NERC "Balancing Standard Proof-of-Concept Field Test" which has established a new metric, balancing authority ACE limit (BAAL), as a possible substitute for CPS2. Participants in the field test have a waiver from meeting the CPS2 requirement for the duration of the field test. As a substitute, the field test participants are required to comply with BAAL limits, which have been established on a trial basis.[5] PJM measures the total number of minutes the BAAL limit is exceeded (high or low) compared to the total number of minutes for a month, with a passing level for this goal being set at 98 percent.

PJM's CPS/BAAL Performance

As Figure F-1 shows, PJM's performance relative to both the CPS1 and BAAL metrics was acceptable in calendar year 2007.

Figure F-1 PJM CPS1 and BAAL performance: Calendar year 2007



5 See PJM. "Manual 12: Balancing Operations," Revision 16 (November 1, 2007), pp. 14-17.

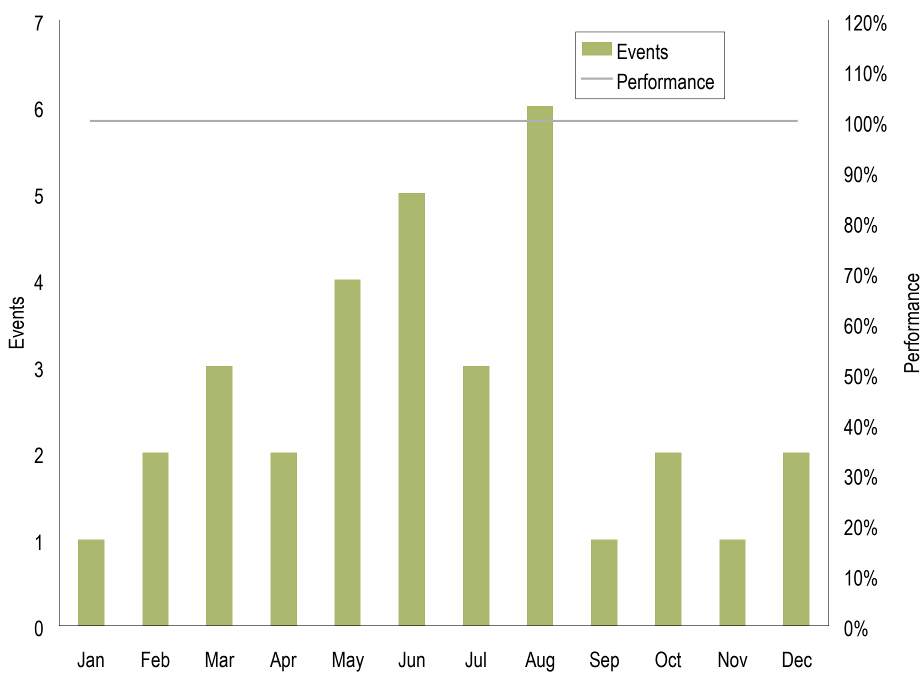
PJM dispatchers have to balance both ACE and frequency. Meeting the CPS1 standard requires balancing ACE and frequency on a monthly, running-average basis. Meeting the BAAL standard requires PJM dispatchers maintaining interconnection frequency within a predefined frequency profile under all conditions (normal and abnormal) to prevent frequency-related instability, unplanned tripping of load or generation, or uncontrolled separation or cascading outages that adversely impact the reliability of the interconnection.

PJM's DCS Performance

A dispatch performance metric that is directly related to synchronized reserve is the disturbance control standard (DCS).[6] DCS measures how well PJM dispatch recovers from a disturbance. A disturbance is defined as any ACE deviation greater than, or equal to, 80 percent of the magnitude of PJM's most severe single contingency loss. PJM currently interprets this to be any ACE deviation greater than 800 MW. Compliance with the NERC DCS is recovery to zero or predisturbance level within 15 minutes.

PJM experienced 31 DCS events during calendar year 2007 and successfully recovered from all of them. All events were caused by a major unit's tripping. Recovery times ranged from two minutes to 15 minutes. Figure F-2 illustrates the event count and performance by month. All of the events resulted in low ACE. The solution for most of the events was to declare a 100 percent spinning event.

Figure F-2 DCS event count and PJM performance (By month): Calendar year 2007



6 For more information on the NERC DCS, see "Standard BAL-002-0 — Disturbance Control Performance" (April 1, 2005) < ftp://www.nerc.com/pub/sys/all_updl/standards/rs/BAL-002-0.pdf > (61 KB).

Regulation Capacity, Daily Offers, Offered and Eligible, Hourly Assigned

The regulation market-clearing price (RMCP) is determined algorithmically by the PJM Market Operations Group. First, a theoretical, optimized energy dispatch is done based on current unit status and forecast LMP. Then the Market Operations Group creates a supply curve for regulation and for synchronized reserve of available units and their associated merit-order prices. Finally, the Market Operations Group assigns regulation and synchronized reserve to units in increasing order of price until the regulation MW and the synchronized reserve requirements are satisfied. The price of the most expensive unit required to satisfy the regulation requirement is the RMCP. Calculating the supply curves for three products (energy, regulation and synchronized reserve) interactively is complicated, but necessary to achieve the lowest overall cost after first taking into account units that self-schedule. In the event it is not possible to satisfy both regulation and synchronized reserve, regulation has the higher priority.

- Regulation Capacity. The sum of the regulation MW capability of all generating units which have qualified to participate in the Regulation Market is the theoretical maximum regulation capacity. This maximum regulation capacity varies over time because units that are certified for regulation may be decommissioned, fail regulation testing or be removed from the Regulation Market by their owners.

- Regulation Offers. All owners of generating units qualified to provide regulation may, but are not required to, offer their regulation capacity daily into the Regulation Market using the PJM market user interface. Regulating units may also self-schedule. Self-scheduled units have zero lost opportunity cost (LOC) and are the first to be assigned. Demand resources are eligible to offer regulation although during 2007 none qualified to do so. Demand resources have an LOC of zero. Under PJM rules, no more than 25 percent of the total regulation requirement may be supplied by demand resources. Total regulation offers are the sum of all regulation-capable units that offer regulation into the market for the day and that are not out of service or fully committed to provide energy. Owners of units that have entered offers into the PJM market user interface system have the ability to set unit status to “unavailable” for regulation for the day, or for a specific hour or set of hours. They also have the ability to change the amount of regulation MW offered in each hour. Unit owners do not have the ability to change their regulation offer price during a day. All regulation offers are summed to calculate the total daily regulation offered, a figure that changes each hour.

- Regulation Offered and Eligible. Sixty minutes before the market hour, PJM runs synchronized reserve and regulation market-clearing software (SPREGO) to determine the amount of Tier 2 synchronized reserve required, to develop regulation and synchronized reserve supply curves, to assign regulation and synchronized reserve to specific units and to determine the RMCP. All regulation resource units which have made offers in the daily Regulation Market are evaluated by SPREGO for regulation. SPREGO then excludes units according to the following ordered criteria: a) Daily or hourly unavailable units; b) Units for which the economic minimum is set equal to economic maximum (unless the unit is a hydroelectric unit or has self-scheduled regulation); c) Units which are assigned synchronized reserve; d) Units for which regulation minimum is set equal to regulation maximum (unless the unit is a hydroelectric unit or has self-scheduled regulation); e) Units that are offline (except combustion turbine units).

Even after SPREGO has run and selected units for regulation, PJM dispatchers can dispatch units uneconomically for several reasons including: to control transmission constraints; to avoid overgeneration during periods of minimum generation alert; to remove a unit temporarily unable to regulate; or to remove a unit with a malfunctioning data link.

For each offered and eligible unit in the regulation supply, the regulation total offer price is calculated using the sum of the unit's regulation offer cost and the opportunity cost based on the forecast LMP, unit economic minimum and economic maximum, regulation minimum and regulation maximum, startup costs and relevant offer schedule. The MW offered and the calculated regulation offered prices are used to create a regulation supply curve. The Regulation and Synchronized Reserve Markets are cleared interactively 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, interarea transfer limits, resource distribution factors, self-scheduled resources, limited fuel resources, bilateral transactions, hydrological constraints, generation requirements and reserve requirements.

- Cleared Regulation. Regulation actually assigned by SPREGO is cleared regulation. The clearing price established by SPREGO becomes the final clearing price. In real time, units that have been assigned regulation and synchronized reserve are expected to provide regulation and synchronized reserve for the designated hour. At any time before or during the hour, PJM dispatchers can redispatch units for reliability reasons. Such redispatch leads to a disparity between cleared regulation and settled regulation.

- Settled Regulation. Units providing regulation are compensated at the clearing price times their actual MW provided (as opposed to cleared MW) plus any actual lost opportunity costs associated with providing regulation. The cost per MW of settled regulation can be higher than the regulation clearing price because there can be a difference between actual and cleared MW, as well as real-time versus forecast nodal prices.

APPENDIX G – FINANCIAL TRANSMISSION AND AUCTION REVENUE RIGHTS

Appendix G provides examples of topics related to Financial Transmission Rights (FTRs) and Auction Revenue Rights (ARRs):

- The sources of total congestion revenue and the determination of FTR target allocations and congestion receipts;
- The procedure for prorating ARRs when transmission capability limits the number of ARRs that can be allocated; and
- The establishment of ARR target allocations and credits through the Annual FTR Auction.

FTR Target Allocations and Congestion Revenue

Table G-1 shows an example of the sources of total congestion revenue and the determination of FTR target allocations and congestion receipts.

Table G-1 Congestion revenue, FTR target allocations and FTR congestion credits: Illustration

Day-Ahead Congestion Revenue						
Pricing Node	Day-Ahead Congestion Price	Day-Ahead Load	Load Congestion Payments	Day-Ahead Generation	Generation Congestion Credits	Transmission Congestion Charges
A	$10	0	$0	100	$1,000	($1,000)
B	$15	50	$750	0	$0	$750
C	$20	50	$1,000	100	$2,000	($1,000)
D	$25	50	$1,250	0	$0	$1,250
E	$30	50	$1,500	0	$0	$1,500
Total		200	$4,500	200	$3,000	$1,500
Balancing Congestion Revenue						
Pricing Node	Real-Time Congestion Price	Load Deviation	Load Congestion Payments	Generation Deviation	Generation Congestion Credits	Transmission Congestion Charges
A	$8	0	$0	0	$0	$0
B	$18	0	$0	0	$0	$0
C	$25	3	$75	5	$125	($50)
D	$20	(5)	($100)	0	$0	($100)
E	$40	7	$280	0	$0	$280
Total		5	$255	5	$125	$130
Transmission congestion charges accounting						
Balancing transmission congestion charges						$130
+Day-ahead transmission congestion charges						$1,500
=Total transmission congestion charges						$1,630
FTR Target Allocations						
Path	Day-Ahead Path Price	FTR MW	FTR Target Allocations	Positive FTR Target Allocations	Negative FTR Target Allocations	
A-C	$10	50	$500	$500	$0	
A-D	$15	50	$750	$750	$0	
D-B	($10)	25	($250)	$0	($250)	
B-E	$15	50	$750	$750	$0	
Total		175	$1,750	$2,000	($250)	
Congestion accounting						
Transmission congestion charges						$1,630
+Negative FTR target allocations						$250
=Total congestion charges						$1,880
Positive FTR target allocations				$2,000		
-FTR congestion credits				$1,880		
=Congestion credit deficiency				$120		
FTR payout ratio				0.94		

ARR Prorating Procedure

Table G-2 shows an example of the prorating procedure for ARRs. If line A-B has a 100 MW rating, but ARR requests from two customers together would impose 175 MW of flow on it, the service request would exceed its capability by 75 MW. The first customer's ARR request (ARR #1) is for a total of 300 MW with a 0.50 impact on the constrained line. It would thus impose 150 MW of flow on the line. The second customer's request (ARR #2) is for a total of 100 MW with a 0.25 impact and would impose an additional 25 MW on the constrained line.

Table G-2 ARR allocation prorating procedure: Illustration

Line A-B Rating = 100 MW						
ARR #	Path	Per MW Effect on Line A-B	Requested ARRs	Resulting Line A-B Flow	Prorated ARRs	Prorated Line A-B Flow
1	C-D	0.50	300	150	150	75
2	E-F	0.25	100	25	100	25
Total			400	175	250	100

Equation G-1 Calculation of prorated ARRs

Individual prorated MW =
(Line capability) • (Individual requested MW / Total requested MW) • (1 / per MW effect on line).

The equation would then be solved for each request as follows:

ARR #1 prorated MW award = (100 MW) • (300 MW / 400 MW) • (1 / 0.50) = 150 MW; and

ARR #2 prorated MW award = (100 MW) • (100 MW / 400 MW) • (1 / 0.25) = 100 MW.

Together the prorated, awarded ARRs would impose a flow equal to line A-B's capability (150 MW • 0.50) + (100 MW • 0.25) = 100 MW.

ARR Credits

Table G-3 shows an example of how ARR target allocations are established, how FTR auction revenue is generated and how ARR credits are determined. The purchasers of FTRs pay and the holders of ARRs are paid based on cleared nodal prices from the Annual FTR Auction. If total revenue from the auction is greater than the sum of the ARR target allocations, then the surplus is used to offset any FTR congestion credit deficiencies occurring in the hourly Day-Ahead Energy Market. For example, the FTR auction revenue is only $75 for the ARR on line A-D while the ARR target allocation is $150. The surplus FTR auction revenue from the other ARR paths is enough to cover the $75 deficiency and fulfill the ARR target allocation of $150.

Table G-3 ARR credits: Illustration

Path	Annual FTR Auction Path Price	ARR MW	ARR Target Allocation	FTR MW	FTR Auction Revenue	ARR Credits
A-C	$10	10	$100	10	$100	$100
A-D	$15	10	$150	5	$75	$150
B-D	$10	0	$0	20	$200	$0
B-E	$15	10	$150	5	$75	$150
Total		30	$400	40	$450	$400
ARR payout ratio = ARR credits / ARR target allocations = $400 / $400 = 100%						
Surplus ARR revenue = FTR auction revenue - ARR credits = $450 - $400 = $50						

APPENDIX H – CALCULATING LOCATIONAL MARGINAL PRICE

In order to understand the relevance of various measures of locational marginal price (LMP), it is important to understand exactly how average LMPs are calculated across time and across buses. This appendix explains how PJM calculates average LMP and load-weighted, average LMP for the system, for a zone and, by extension, for any aggregation of buses, for an hour, for a day and for a year.[1]

Real-Time Hourly Integrated LMP and Real-Time Hourly Integrated Load

In PJM a real-time LMP is calculated at every bus for every five-minute interval.

The system real-time, five-minute, average LMP is the load-weighted, average LMP for that five-minute interval, calculated using the five-minute LMP at each load bus and the corresponding five-minute load at each load bus in the system. The sum of the product of the five-minute LMP and the five-minute load at each bus, divided by the sum of the five-minute loads across the buses equals the system load-weighted, average LMP for that five-minute interval.

In PJM, the real-time hourly LMP at a bus is equal to the simple average of each hour's 12 five-minute interval LMPs at that bus. This is termed the hourly integrated LMP at the bus. The hourly load at a bus is also calculated as the simple average of each hour's 12 five-minute interval loads at that bus. This is termed the hourly integrated load at the bus. The hourly values for LMP and load are the basis of PJM's settlement calculations.

Day-Ahead Hourly LMP and Day-Ahead Hourly Load

Zonal, day-ahead hourly aggregate load is assigned to buses in the relevant zone using zonal distribution factors. Zonal distribution factors are calculated from historical real-time, bus-level load within the zone. The day-ahead LMP is calculated at every bus for every hour using these estimated nodal loads plus nodal load from decrement bids (DECs) and price-sensitive load and nodal supply from generation offers and increment offers (INCs). The result is a full set of day-ahead nodal LMPs and cleared, nodal loads. This measure of nodal, day-ahead load is used in system load-weighted, average LMP calculations. This is termed nodal, total day-ahead load here.

Load-Weighted, Average LMP

Real Time

The system real-time, load-weighted, average LMP for an hour is equal to the sum of the product of the hourly integrated bus LMPs for each load bus and the hourly integrated load for each load bus, for the hour, divided by the sum of the hourly integrated bus loads for the hour.

1 The unweighted, average LMP is also referred to as the simple average LMP.

The zonal real-time, load-weighted, average LMP for an hour is equal to the sum of the product of the hourly integrated bus LMPs for each load bus in a zone and the hourly integrated load for each load bus in that zone, divided by the sum of the real-time hourly integrated loads for each load bus in that same zone.

The system real-time, load-weighted, average LMP for a day is equal to the product of the hourly integrated LMPs for each load bus and the hourly integrated load for each load bus, for each hour, summed over every hour of the day, divided by the sum of the hourly integrated bus loads for the system for the day.

The zonal real-time, load-weighted, average LMP for a day is equal to the product of each of the hourly integrated LMPs for each load bus in a zone and the hourly integrated load for each load bus in that zone, for each hour, summed over every hour of the day, divided by the sum of the hourly integrated bus loads at each load bus in that zone for the day.

The system real-time, load-weighted, average LMP for a year is equal to the product of the hourly integrated LMPs and hourly integrated load for each load bus, summed across every hour of the year, divided by the sum of the hourly integrated bus loads at each load bus in the system for each hour in the year.

The zonal real-time load-weighted, average LMP for a year is equal to the product of each of the hourly integrated bus LMPs and hourly integrated load for each load bus in a zone, summed across every hour of the year, divided by the sum of the hourly integrated bus loads at each load bus in that zone for each hour in the year.

Day Ahead

The system day-ahead, load-weighted, average LMP for an hour is equal to the sum of the product of the hourly LMP at each load bus and the corresponding nodal, total day-ahead hourly load at each load bus in the system, divided by the sum of the nodal, total day-ahead hourly loads across the buses.

The zonal day-ahead, load-weighted, average LMP for an hour is equal to the sum of the product of the hourly bus LMPs for each load bus in a zone and the hourly estimated load distribution factors for each load bus in that zone. The zonal day-ahead, load-weighted, average LMP does not use the full nodal, total day-ahead hourly loads used in the other calculations of day-ahead average LMP.

The system day-ahead, load-weighted, average LMP for a day is equal to the product of the hourly day-ahead LMPs for each load bus and the nodal, total hourly day-ahead load for each load bus, for each hour, summed over every hour of the day, divided by the sum of the nodal, total hourly day-ahead loads for the system for the day.

The zonal day-ahead, load-weighted, average LMP for a day is equal to the product of each of the hourly day-ahead LMPs for each load bus in a zone and the hourly estimated load distribution factors for each load bus in that zone and the hourly day-ahead load for the zone, summed over every hour of the day, and divided by the corresponding estimated total zonal load for the day. Again, the zonal day-ahead, load-weighted, average LMP does not use the full nodal, total day-ahead hourly loads used in the other calculations of day-ahead average LMP.

The system day-ahead, load-weighted, average LMP for a year is equal to the product of the hourly LMPs and nodal, total hourly load for each load bus, summed across every hour of the year, divided by the sum of the nodal, total hourly bus loads at each load bus in the system for each hour in the year.

The zonal day-ahead, load-weighted, average LMP for a year is equal to the product of each of the hourly LMPs for each load bus in a zone and the hourly estimated load distribution factors for each load bus in that zone and the hourly day-ahead load for the zone, summed over every hour of the year, and divided by the total estimated zonal load for the years. Again, the zonal day-ahead, load-weighted, average LMP does not use the full nodal, total day-ahead hourly loads used in the other calculations of day-ahead average LMP.

Equation H-1 LMP calculations

	i = 5-minute interval	h = 12 intervals = hour i = 1..12	d = 24 hours = day h = 1..24	y = 365 days = 8,760 hours = year d = 1..365
Bus average	LMP_{bi}	$LMP_{bh} = \frac{\sum_{i=1}^{12} LMP_{bi}}{12}$	$LMP_{bd} = \frac{\sum_{h=1}^{24} LMP_{bh}}{24}$	$LMP_{by} = \frac{\sum_{h=1}^{8760} LMP_{bh}}{8760}$
Bus load-weighted average			$lwLMP_{bd} = \frac{\sum_{h=1}^{24}(LMP_{bh} \cdot Load_{bh})}{\sum_{h=1}^{24} Load_{bh}}$	$lwLMP_{by} = \frac{\sum_{h=1}^{8760}(LMP_{bh} \cdot Load_{bh})}{\sum_{h=1}^{8760} Load_{bh}}$
System average	$LMP_{si} = \frac{\sum_{b=1}^{B} LMP_{bi}}{B}$	$LMP_{sh} = \frac{\sum_{b=1}^{B} LMP_{bh}}{B}$	$LMP_{sd} = \frac{\sum_{h=1}^{24} \frac{\sum_{b=1}^{B}(LMP_{bh} \cdot Load_{bh})}{\sum_{b=1}^{B} Load_{bh}}}{24}$	$LMP_{sy} = \frac{\sum_{h=1}^{8760} \frac{\sum_{b=1}^{B}(LMP_{bh} \cdot Load_{bh})}{\sum_{b=1}^{B} Load_{bh}}}{8760}$
System load-weighted average	$lwLMP_{si} = \frac{\sum_{b=1}^{B}(LMP_{bi} \cdot Load_{bi})}{\sum_{b=1}^{B} Load_{bi}}$	$lwLMP_{sh} = \frac{\sum_{b=1}^{B}(LMP_{bh} \cdot Load_{bh})}{\sum_{b=1}^{B} Load_{bh}}$	$lwLMP_{sd} = \frac{\sum_{h=1}^{24}\sum_{b=1}^{B}(LMP_{bh} \cdot Load_{bh})}{\sum_{h=1}^{24}\sum_{b=1}^{B} Load_{bh}}$	$lwLMP_{sy} = \frac{\sum_{h=1}^{8760}\sum_{b=1}^{B}(LMP_{bh} \cdot Load_{bh})}{\sum_{h=1}^{8760}\sum_{b=1}^{B} Load_{bh}}$

APPENDIX I – LOAD DEFINITIONS

PJM measures load in two ways: eMTR load and accounting load. In the *2007 State of the Market Report,* both measures of load are used, as appropriate for the specific analysis. The measures of load and their applications changed after PJM's June 1, 2007, implementation of marginal losses.

eMTR Load

PJM uses eMTR load to measure peak loads and as the basis for accounting load determinations. eMTR load is supplied by PJM electricity distribution companies (EDCs) and generators and is based on the metered MWh values of tie lines and the metered values of generation MWh. For PJM Western Region and Southern Region EDCs (ComEd, AEP, DAY, DLCO, AP and Dominion), eMTR load values inherently include local, EHV (extra-high-voltage) and non-EHV losses. eMTR load values for PJM Mid-Atlantic Region EDCs inherently include local and non-EHV losses plus an allocation of metered Mid-Atlantic Region EHV losses.

eMTR load is used in state of the market reports to measure peak load. This is the total amount of generation output and net energy imports required to meet the peak load on the system, including losses.

Accounting Load

PJM uses accounting load in the settlement process. Prior to June 1, 2007, accounting load for all EDCs was equal to eMTR load. In other words, prior to June 1, 2007, accounting load included losses. Since the implementation of marginal losses on June 1, 2007, two types of accounting load have been calculated: accounting load with losses and accounting load without losses. Accounting load, without losses, for Western Region and Southern Region EDCs is calculated by subtracting non-EHV and EHV losses from eMTR load. Accounting load, without losses, for Mid-Atlantic Region EDCs is calculated by subtracting non-EHV losses and the EHV loss allocations from eMTR load. Since June 1, 2007, accounting load without losses has represented the actual retail customer load and is referred to here as accounting load.

Accounting load is used in the *2007 State of the Market Report* to measure daily, monthly and annual load. Accounting load is also used in the *2007 State of the Market Report* to weight LMP in load-weighted LMP calculations. Prior to June 1, 2007, accounting load includes losses and after June 1 accounting load excludes losses. Prior to June 1, LMP did not include losses. After June 1, LMP has included losses.

APPENDIX J – CALCULATING MARGINAL LOSSES

Since June 1, 2007, PJM's locational marginal price (LMP) has been comprised of three distinct components: system energy price, marginal losses and congestion.

Equation J-1 LMP components

$$\gamma_i = \lambda_{ref} + \gamma_i^L + \lambda_i^C,$$

where γ_i is the LMP at bus$_i$, λ_{ref} is the price at the reference bus, γ_i^L is the marginal loss component of the LMP at bus$_i$, and λ_i^C is the congestion component at bus$_i$.

Marginal Losses versus Average Losses

On June 1, 2007, PJM revised its methodology for determining transmission losses from average cost to nodal, marginal losses. Marginal loss pricing is based on the calculation of the incremental losses incurred as a result of a 1-MW increase in production. Marginal loss pricing permits more efficient system dispatch and decreased total production cost.

Total, Average and Marginal Losses

Power flowing across a transmission line results in losses proportional to the square of the power delivered. The materials constituting the conductors and other elements of the transmission system exhibit a characteristic impedance to the flow of power. Total transmission losses are proportional to the product of the square of the current flowing across the line, I, and the resistance of the line, R. Transmission losses are proportional to the square of the power consumed by the load, P, and the resistance of the line, R, and inversely proportional to the square of the voltage, V.[1] While this relationship differs somewhat in an alternating current (AC) as compared to a direct current (DC) system, the magnitude of losses can be approximated by the equation:

Equation J-2 Transmission losses

$$\text{Total Losses} = I^2 R = \left(P^2 / V^2\right) R = aP^2,$$

where $a = R / V^2$.

Since losses from a power flow of P are equal to aP^2, the average losses per MW of flow across a transmission element are:

1 Equation J-2 incorporates the substitution of the relationship I=P/V, derived from Ohm's Law, for the variable I.

Equation J-3 Average losses

Average Losses $= \left(aP^2 / P\right) = aP$.

Marginal losses are the incremental losses resulting from an increase in production and are equal to the first derivative of total losses:

Equation J-4 Marginal losses

Marginal Losses $= \frac{d}{dP}\left(aP^2\right) = 2aP$.

Marginal losses for an additional MW of flow are, therefore, equal to twice the average losses for the associated total flow.

Effect of Marginal Losses on LMP

To incorporate the effect of marginal losses on LMP, a penalty factor must be calculated, Pf_i, for each bus$_i$ defined as:

Equation J-5 Penalty factor

$$Pf_i = \frac{1}{\left(1 - \frac{\partial P_{loss}}{\partial P_i}\right)} .$$

The term $\frac{\partial P_{loss}}{\partial P_i}$ is called the loss factor and represents the change in system losses for a change in power P at bus$_i$.

If an increase in power results in an increase in losses, then the loss factor is positive:

$$0 < \frac{\partial P_{loss}}{\partial P_i} < 1 ,$$

and the resultant penalty factor at bus$_i$ would be greater than unity:

$$Pf_i = \frac{1}{\left(1 - \frac{\partial P_{loss}}{\partial P_i}\right)} > 1 .$$

Conversely, if an increase in power results in a decrease in losses, then the loss factor is negative:

$$-1 < \frac{\partial P_{loss}}{\partial P_i} < 0 ,$$

and the resultant penalty factor at bus_i would be less than unity:

$$Pf_i = \frac{1}{\left(1 - \frac{\partial P_{loss}}{\partial P_i}\right)} < 1 .$$

The unit offer curve of a generator at each bus_i is multiplied by the respective penalty factor at bus_i. (See Equation J-5.) If the penalty factor at bus_i is greater than unity, system losses would be made greater by increasing the output of a generator at bus_i, and the unit offer curve would shift upward. Similarly, if the penalty factor at bus_i is less than unity, system losses would be reduced by increasing the output of a generator at bus_i, and the unit offer curve would shift downward. In an unconstrained system, any difference in LMP between bus_i, γ_i, and the reference bus, λ_{ref}, is the result of losses.

Loss Revenue Surplus

As demonstrated in Equation J-4, revenues resulting from marginal losses are approximately twice those collected from average losses. As demonstrated in Equation J-2, losses are proportional to the square of the power, P. As such, two loads, of equal size, served simultaneously result in losses four times greater than the losses incurred in serving either of them separately. By utilizing the penalty factor in the dispatch, losses are paid based on marginal losses rather than based on average losses. By paying for losses based on marginal instead of average losses, an overcollection occurs. Using the example of two loads, of equal size, being served simultaneously, the marginal losses associated with the combined effect of the loads is greater than the sum of the losses incurred by each load separately, thus resulting in an overcollection. These excess loss revenues are allocated to transmission users based on load plus export ratio shares:

Equation J-6 Excess loss revenue allocation

$$\text{Loss Credit} = (\text{Total Loss Surplus}) \bullet \left(\frac{\text{Customer total MWh delivered to load} + \text{exports}}{\text{Total PJM MWh delivered to load} + \text{exports}}\right).$$

APPENDIX K – CALCULATION AND USE OF GENERATOR SENSITIVITY/UNIT PARTICIPATION FACTORS

Sensitivity factors define the impact of each marginal unit on locational marginal price (LMP) at every bus on the system.[1] The availability of sensitivity factor data permits the refinement of analyses in areas where the goal is to calculate the impact of unit characteristics or behavior on LMP.[2] These factors include the impact on LMP of the cost of fuel by type, the cost of emissions allowances by type, frequently mitigated unit adders and unit markup by unit characteristics.[3]

Generator sensitivity factors, or unit participation factors (UPFs), are calculated within the least-cost, security-constrained optimization program. For every five-minute system solution, UPFs describe the incremental amount of output that would have to be provided by each of the current set of marginal units to meet the next increment of load at a specified bus while maintaining total system energy balance. A UPF is calculated from each marginal unit to each load bus for every five-minute interval. In the absence of marginal losses, the UPFs associated with the set of marginal units in any given interval, for a particular load bus, always sum to 1.0. UPFs can be either positive or negative. A negative UPF for a unit with respect to a specific load bus indicates that the unit would have to be backed down for the system to meet the incremental load at the load bus.

Within the context of a security-constrained, least-cost dispatch solution for an interval, during which the LMP at the marginal unit's bus equals the marginal unit's offer, consistent with its output level, LMP at each load bus is equal to each marginal unit's offer price, multiplied by its UPF, relative to that load bus. In some cases, the bus price for the marginal unit may not equal the calculated price based on the offer curve of the marginal unit. These differences are the result of unit dispatch constraints, transmission constraints and the interactions among them. Any difference between the price based on the offer curve and the actual bus price is categorized as "constrained off." In addition, final LMPs calculated using UPFs may differ slightly from PJM's posted LMPs as a result of rounding and missing data. Such differentials are identified as not available (NA).

1 For another review of sensitivity factors, please refer to "PJM 101: The Basics" (June 14, 2007), p. 119 <http://www.pjm.com/services/training/downloads/pjm101part1.pdf> (6.69 MB).

2 The PJM Market Monitoring Unit (MMU) identified applications for sensitivity factors and began to save sensitivity factors in 2006.

3 Before the *2006 State of the Market Report,* state of the market reports had shown the impact of each marginal unit on load and on LMP based on engineering estimates whenever there were multiple marginal units.

Table K-1 shows the relationship between marginal generator offers and the LMP at a specific load bus X in a given five-minute interval.

Table K-1 LMP at bus X

Generator	UPF Bus X	Offer	Generator Contribution to LMP at X	Generator Contribution to LMP at X (Percentage)
A	0.5	$200.00	$100.00	85%
B	0.4	$40.00	$16.00	14%
C	0.1	$10.00	$1.00	1%
			LMP at X	
			$117.00	100%

Table K-1 shows three hypothetical, marginal generators at three different buses (A, B and C); each affects LMP at load bus X. Each generator's effect on LMP at X is measured by the UPF of that unit with respect to X. The UPF for generator A is 0.5 relative to load bus X, meaning that 50 percent of marginal Unit A's offer price contributes directly to the LMP at X. Since A has an offer price of $200, generator A contributes $100, or UPF times the offer, to the LMP at load bus X. The UPFs from all the marginal units to the load bus must sum to 1.0, so that the marginal units explain 100 percent of the load bus LMP. Generators B and C have UPFs of 0.4 and 0.1, respectively, and offer prices of $40 and $10, respectively, and therefore contribute $16 and $1, respectively, to the LMP at X. Together, the marginal units' offers multiplied by their UPFs with respect to load bus X explain the interval LMP at the load bus.

Hourly Integrated LMP Using UPF

Table K-1 describes the relationship between LMP and UPFs for a five-minute interval. Since PJM charges loads and credits generators on the basis of hourly integrated LMP, the relationship among marginal unit offers, UPFs and the hourly integrated LMP must be specified.

The relevant variables and notation are defined as follows:

h = hour,

i = five-minute interval,

t = year, where t designates the current year and t-1 designates the previous year,

b = a specified load bus, where b ranges from 1 to B,

g = a specified marginal generator, where g ranges from 1 to G, and

L = interval-specific load.

The hourly integrated load at a bus is the simple average of the 12 interval loads at a bus in a given hour:

Equation K-1 Hourly integrated load at a bus

$$Load_{bh} = \frac{\sum_{i=1}^{12} L_{bi}}{12}$$

Load bus *LMP* is determined on a five-minute basis and is a function of marginal unit offers and UPFs in that interval:

Equation K-2 Load bus LMP

$$LMP_{bi} = \sum_{g=1}^{G} \left(Offer_{gi} \bullet UPF_{gbi} \right)$$

The hourly integrated *LMP* at a bus is the simple average of the 12 interval LMPs at a bus in a given hour:

Equation K-3 Hourly integrated LMP at a bus

$$LMP_{bh} = \frac{\sum_{i=1}^{12} LMP_{bi}}{12}$$

Total cost *(TC)* of the system in the hour is equal to the product of the hourly integrated LMP and the hourly integrated load at each bus summed across all buses in the hour:

Equation K-4 Hourly total system cost

$$TC_h = \sum_{b=1}^{B} \left(LMP_{bh} \bullet Load_{bh} \right)$$

System load-weighted LMP for the hour *(*$LMPSYS_h$*)* is equal to the total hourly system cost *(TC)* divided by the sum of a bus's simple 12 interval average loads in the hour:

Equation K-5 Hourly load-weighted LMP

$$LMPSYS_h = \frac{TC_h}{\sum_{b=1}^{B} Load_{bh}}$$

The system annual, load-weighted, average *(SLW)* LMP for the year is:

Equation K-6 System annual, load-weighted, average LMP

$$Annual\_SLW\_LMP = \sum_{h=1}^{8760} \frac{TC_h}{\sum_{b=1}^{B} Load_{bh}}$$

Hourly Integrated Markup Using UPFs

Markup is defined as the difference between the price from the price-based offer curve and the cost from the cost-based offer curve at the operating point of a specific marginal unit. UPFs can be used to calculate the impact of marginal unit markup behavior on the LMP at any individual load bus and of the LMP at any aggregation of load buses including the system LMP. The resultant markup component of LMP is a measure of market power, a market performance metric. The markup component of LMP is based on the markup of the actual marginal units and is not based on a redispatch of the system using cost-based offers.

To determine the impact of marginal unit markup behavior on system LMP on an hourly integrated basis, the following steps are required.

Total cost *(TC)* of the system in the hour is equal to the product of the average LMP and the average load at each bus summed across all buses in the hour which, using the definitions above, can be expressed in terms of marginal unit offers and UPFs:

Equation K-7 UPF-based system hourly total cost

$$TC_h = \sum_{b=1}^{B} \left(LMP_{bh} \bullet Load_{bh} \right) = \sum_{b=1}^{B} \left[Load_{bh} \bullet \frac{\sum_{i=1}^{12} \sum_{g=1}^{G} \left(Offer_{gi} \bullet UPF_{gbi} \right)}{12} \right]$$

System load-weighted LMP for the hour is equal to total hourly system cost divided by the sum of the bus's simple 12 interval average loads in the hour:

Equation K-8 System load-weighted LMP

$$LMPSYS_h = \frac{TC_h}{\sum_{b=1}^{B} Load_{bh}} = \frac{\sum_{b=1}^{B}\left[Load_{bh} \bullet \frac{\sum_{i=1}^{12}\sum_{g=1}^{G}\left(Offer_{gi} \bullet UPF_{gbi}\right)}{12}\right]}{\sum_{b=1}^{B} Load_{bh}}$$

Holding dispatch and marginal units constant, the system, hourly load-weighted LMP based on cost offers of the marginal units, shown in Equation K-9, is found by substituting the marginal unit cost offers into Equation K-8:

Equation K-9 Cost-based offer system, hourly load-weighted LMP

$$LMPSYSCost_h = \frac{TC_h}{\sum_{b=1}^{B} Load_{bh}} = \frac{\sum_{b=1}^{B}\left[Load_{bh} \bullet \frac{\sum_{i=1}^{12}\sum_{g=1}^{G}\left(CostOffer_{gi} \bullet UPF_{gbi}\right)}{12}\right]}{\sum_{b=1}^{B} Load_{bh}}$$

The contribution of the markup by marginal units to system LMP for the hour is shown in Equation K-10 below:

Equation K-10 Impact of marginal unit markup on LMP

$$MarkUp_h = LMPSYS_h - LMPSYSCost_h$$

UPF–Weighted, Marginal Unit Markup

The price-cost markup index for a marginal unit provides a measure of market power based on the behavior of a single unit of an individual generator:

Equation K-11 Price-cost markup index

$$MarkUp_{gi} = \frac{Offer_{gi} - CostOffer_{gi}}{Offer_{gi}}$$

The UPF load-weighted, marginal unit markup (measure of unit behavior) provides a measure of market power for a given hour for the system or any aggregation of load buses. This measure of system performance equals the weighted-average markup index for all marginal units, which is a measure of unit behavior:

Equation K-12 UPF load-weighted, marginal unit markup

$$lwMarkUp_h = \frac{\sum_{b=1}^{B}\left[\frac{\sum_{i=1}^{12}\sum_{g=1}^{G}\left(MarkUp_{gi} \bullet UPF_{gbi}\right)}{12} \bullet Load_{bh}\right]}{\sum_{b=1}^{B} Load_{bh}}$$

Hourly Integrated Historical, Cost-Adjusted, Load-Weighted LMP Using UPFs

UPFs can be used to calculate historical, cost-adjusted, load-weighted LMP for a specific time period. This method is used to disaggregate the various components of LMP, including all the separate components of unit marginal cost and unit markup, and to calculate the contributions of each component to system LMP.

The extent to which fuel cost, emission allowance cost, variable operation and maintenance cost (VOM) and markup affect the offers of marginal units depends on the share of the offer that each component represents. The percentage of a unit's offer that is based on each of the components is given as the following:

Fuel:	$\%Fuel_{gi}$
SO_2:	$\%SO_{2\,gi}$
NO_x:	$\%NO_{x\,gi}$
VOM:	$\%VOM_{gi}$
Markup:	$\%Mark\text{-}Up_{gi}$

The proportion of specific components of unit offers is calculated on an interval and on a unit-specific basis. Cost components are determined for each marginal unit for the relevant time periods:

Delivered fuel cost per MWh: FC_{gt}.

Sulfur dioxide, emission-related cost per MWh: $SO_{2\ gt}$.

Nitrogen oxide, emission-related cost per MWh: $NO_{x\ gt}$.

Fuel costs *(FC)* are specific to the unit's location, the unit's fuel type and the time period in question. For example:

FC_{gt} = Avg FC in specified "Current Year's Period" (e.g., April 1, 2007); and

FC_{gt-1} = Avg FC in specified "Previous Year's Period" (e.g., April 1, 2006).

Fuel-Cost-Adjusted LMP

The portion of a marginal generator's offer that is related to fuel costs for a specified period is adjusted to reflect the previous period's fuel costs. Subtracting the proportional fuel-cost adjustment from the marginal generator's interval-specific offer provides the fuel-cost-adjusted offer (*FCA*):

Equation K-13 Fuel-cost-adjusted offer

$$FCAOffer_{gi} = Offer_{gi} \bullet \left[1 - \%Fuel_{gi} \bullet \left(\frac{FC_{gt} - FC_{gt-1}}{FC_{gt}} \right) \right]$$

Using $FCAOffer_{gi}$ for all marginal units in place of the unadjusted offers $(offer_{gi})$ in Equation K-8 (i.e., the system load-weighted LMP equation), results in the hourly fuel-cost-adjusted, load-weighted LMP:

Equation K-14 Fuel-cost-adjusted, load-weighted LMP

$$LWFCAsysLMP_h = \frac{TCFCA_h}{\sum_{b=1}^{B} Load_{bh}} = \frac{\sum_{b=1}^{B} \left[Load_{bh} \bullet \frac{\sum_{i=1}^{12} \sum_{g=1}^{G} \left(FCAOffer_{gi} \bullet UPF_{gbi} \right)}{12} \right]}{\sum_{b=1}^{B} Load_{bh}}$$

The systemwide annual, fuel-cost-adjusted, load-weighted *(SFCALW)* LMP for the year is given by the following equation:

Equation K-15 Systemwide annual, fuel-cost-adjusted, load-weighted LMP

$$Annual\_SFCALW\_LMP = \sum_{h=1}^{8760} \frac{TCFCA_h}{\sum_{b=1}^{B} Load_{bh}}$$

Cost-Adjusted LMP

Summing the unit's specific historical, cost-adjusted component effects and subtracting that sum from the unit's unadjusted offer provides the historical, cost-adjusted offer of the unit (*HCAOffer*):

Equation K-16 Unit historical, cost-adjusted offer

$$HCAOffer_{gi} = Offer_{gi} \bullet \left[1 - \%Fuel_{gi} \bullet \left(\frac{FC_{gt} - FC_{gt-1}}{FC_{gt}} \right) - \%NOx_{gi} \bullet \left(\frac{NOx_{gt} - NOx_{gt-1}}{NOx_{gt}} \right) - \%SO2_{gi} \bullet \left(\frac{SO2_{gt} - SO2_{gt-1}}{SO2_{gt}} \right) \right]$$

APPENDIX L – THREE PIVOTAL SUPPLIER TEST

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

The structural test for implementing offer capping set forth in the PJM Amended and Restated Operating Agreement (OA) Schedule 1, Sections 6.4.1(e) and (f) is the three pivotal supplier test. The three pivotal supplier test is applied by PJM on an ongoing basis in order to determine whether offer capping is required for any constraint not exempt from offer capping and for any units not exempt from offer capping. The three pivotal supplier test defined in the OA represents a significant evolution in accuracy because the test is applied in real time using the actual data used by the dispatchers to dispatch the system including transmission constraints and the real-time details of incremental generator availability.

As a result of PJM's implementation of the three pivotal supplier test in real time, the actual competitive conditions associated with each binding constraint are analyzed in real time as they arise. The three pivotal supplier test replaced the prior approach which was to offer cap all units required to resolve a binding constraint. The application of the three pivotal supplier test has meant a reduction in the application of offer capping. As a result of the application of the three pivotal supplier test, offer capping is applied only at times when the local market structure is not competitive and only to those participants with structural market power.

Three Pivotal Supplier Test: Background

By order issued April 18, 2005, the United States Federal Energy Regulatory Commission (FERC) set for hearing, in Docket No. EL04-121-000, PJM's proposal: a) to exempt the AP South Interface from PJM's offer-capping rules; and b) to conduct annual competitive analyses to determine whether additional exemptions from offer capping are warranted. By order issued July 5, 2005, the FERC also set for hearing, in Docket No. EL03-236-006, PJM's three pivotal supplier test. The Commission further set for hearing issues related to the appropriateness of implementing scarcity pricing in PJM. In the July order, the Commission consolidated Docket No. EL04-121-000 and Docket No. EL03-236-006.

On November 16, 2005, PJM filed a "Settlement Agreement" resolving all issues set for hearing in the two section 206 proceedings established by the Commission to address certain aspects of PJM's market power mitigation rules, including the application of the three pivotal supplier test, provisions for scarcity pricing,

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

offer caps for frequently mitigated units and competitive issues associated with certain of PJM's internal interfaces. On December 20, 2005, the presiding administrative law judge certified the "Settlement Agreement" to the Commission as uncontested. On January 27, 2006, in Docket Nos. EL03-236-006, EL04-121-000, 001 and 002, the Commission ordered that the "Settlement Agreement," including the amendments to the PJM Tariff and its OA, was in the public interest and was thereby approved and accepted for filing and made effective as set forth in the "Settlement Agreement."[2]

Market Structure Tests and Market Power Mitigation: Core Concepts

A test for local market power based on the number of pivotal suppliers has a solid basis in economics and is clear and unambiguous to apply in practice. There is no perfect test, but the three pivotal supplier test for local market power strikes a reasonable balance between the requirement to limit extreme structural market power and the goal of limiting intervention in markets when competitive forces are adequate. The three pivotal supplier test for local market power is also a reasonable application of the logic contained in the Commission's market power tests.

The Commission adopted market power screens and tests in the AEP Order.[3] The AEP Order defined two indicative screens and the more dispositive delivered price test. The Commission's delivered price test for market power defines the relevant market as all suppliers who offer at or below the clearing price times 1.05 and, using that definition, applies pivotal supplier, market share and market concentration analyses. These tests are failed if, in the relevant market, the supplier in question is pivotal, has a market share in excess of 20 percent or if the Herfindahl-Hirschman Index (HHI) exceeds 2500. The Commission also recognized that there are interactions among the results of each screen under the delivered price test and that some interpretation is required and, in fact, is encouraged.[4]

The three pivotal supplier test, as implemented, is consistent with the Commission's market power tests, encompassed under the delivered price test. The three pivotal supplier test is an application of the delivered price test to the Real-Time Energy Market, the Day-Ahead Energy Market and the Reliability Pricing Model (RPM) Capacity 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 includes more competitors in its definition of the relevant market than the Commission's delivered price test. While the Commission's delivered price test defines the relevant market to include all offers with costs less than, or equal to, 1.05 times the market price, the three pivotal supplier test includes all offers with costs less than, or equal to, 1.50 times the clearing price for the local market.

The goal of defining the relevant market is to determine those units that are actual competitors to the units that clear in a market. The Commission definition would indicate that, if the marginal unit sets the clearing price based on an offer of $200 per MWh, all units with costs less than, or equal to, $210 per MWh have a competitive effect on the offer of the marginal unit. These units are all defined to be meaningful competitors in the sense that it is assumed that their behavior constrains the behavior of the marginal and inframarginal units. The three pivotal supplier definition would indicate, if the marginal unit sets the clearing price based on an offer of $200 per MWh, that all units with costs less than, or equal to, $300 per MWh have a competitive effect on the offer of the marginal unit. These units are all defined to be meaningful competitors

2 114 FERC ¶ 61,076 (2006).

3 107 FERC ¶ 61,018 (2004) (AEP Order).

4 107 FERC ¶ 61,018 (2004).

in the sense that it is assumed that their behavior constrains the behavior of the marginal and inframarginal units. Clearly, the three pivotal supplier test incorporates a definition of meaningful competitors that is at the high end of inclusive. It is certainly questionable whether a $300 offer meaningfully constrains the offer of a $200 unit. This broad market definition is combined with the recognition that multiple owners can be meaningfully jointly pivotal. The three pivotal supplier test includes three pivotal suppliers while the Commission test includes only one pivotal supplier.

The three pivotal supplier test is also consistent with the Commission's delivered price test in that it tests for the interaction between individual participant attributes and features of the relevant market structure. The three pivotal supplier test is an explicit test for the ability to exercise unilateral market power as well as market power via coordinated action, based on economic theory, which accounts simultaneously for market shares and the supply-demand balance in the market.

The results of the three pivotal supplier test can differ from the results of the HHI and market share tests. The three pivotal supplier test can show the existence of structural market power when the HHI is less than 2500 and the maximum market share is less than 20 percent. The three pivotal supplier test can also show the absence of market power when the HHI is greater than 2500 and the maximum market share is greater than 20 percent. The three pivotal supplier test is more accurate than the HHI and market share tests because it focuses on the relationship between demand and the most significant aspect of the ownership structure of supply available to meet it. A market share in excess of 20 percent does not matter if the holder of that market share is not jointly pivotal and is unlikely to be able to affect the market price. A market share less than 20 percent does not matter if the holder of that market share is jointly pivotal and is likely to be able to affect the market price. Similarly, an HHI in excess of 2500 does not matter if the relevant owners are not jointly pivotal and are unlikely to be able to affect the market price. An HHI less than 2500 does not matter if the relevant owners are jointly pivotal and are likely to be able to affect the market price.[5]

The three pivotal supplier test was designed in light of actual elasticity conditions in load pockets in wholesale power markets in PJM. The price elasticity of demand is a critical variable in determining whether a particular market structure is likely to result in a competitive outcome. A market with a specific set of market structure features is likely to have a competitive outcome under one range of demand elasticity conditions and a noncompetitive outcome under another set of elasticity conditions. It is essential that market power tests account for actual elasticity conditions and that evaluation of market power tests neither ignore elasticity nor make counterfactual elasticity assumptions. As the Commission stated, "In markets with very little demand elasticity, a pivotal supplier could extract significant monopoly rents during peak periods because customers have few, if any, alternatives."[6] The Commission also stated:

> In both of these models, the lower the demand elasticity, the higher the mark-up over marginal costs. It must be recognized that demand elasticity is extremely small in electricity markets; in other words, because electricity is considered an essential service, the demand for it is not very responsive to price increases. These models illustrate the need for a conservative approach in order to ensure competitive outcomes for customers because many customers lack one of the key protections against market power: demand response.[7]

5 For detailed examples, see Joseph E. Bowring, PJM market monitor. "MMU Analysis of Combined Regulation Market," PJM Market Implementation Committee Meeting (December 20, 2006).

6 107 FERC ¶ 61,018 (2004).

7 107 FERC ¶ 61,018 (2004).

The three pivotal supplier test is a reasonable application of the Commission's delivered price test to the case of load pockets that arise in a market based on security-constrained, economic dispatch with locational market pricing and extremely inelastic demand. The three pivotal supplier test also exists in the context of a local market power mitigation rule that relies on a structure test, a participant behavior test and a market impact test. The three pivotal supplier test explicitly incorporates the relationship between supply and demand in the definition of pivotal, and it provides a clear test for whether excess supply is adequate to offset other structural features of the market and results in an adequately competitive market structure. The greater the supply relative to demand, the less likely that three suppliers will be jointly pivotal, all else equal.

The three pivotal supplier test represents a significant modification of the previously existing PJM local market power rule, which did not include an explicit market structure test. The goal of applying a market structure test is to continue to limit the exercise of market power by generation owners in load pockets but to lift offer capping when the market structure makes the exercise of market power less likely. The goal of the three pivotal supplier test, proposed by PJM, was not to weaken the local market power rules but to make them more flexible by adding an explicit market structure test. As recognized by PJM when the local market power rule was proposed in 1997 and has continued to be the case, the local markets created by transmission constraints are generally not structurally competitive. Nonetheless, it is appropriate to have a clear test as to when a local market is adequately competitive to permit the relaxation of local market power mitigation. The three pivotal supplier test proposed by PJM is not a guarantee that suppliers will behave in a competitive manner in load pockets. The three pivotal supplier test is a structural test that is not a perfect predictor of actual behavior. The existence of this risk is the reason that the PJM Tariff language also includes the ability of the MMU to request that the Commission reinstate offer caps in cases where there is not a competitive outcome.

Three Pivotal Supplier Test: Mechanics

The three pivotal supplier test measures the degree to which the supply from three generation suppliers is required in order to meet the demand to relieve a constraint. Two key variables in the analysis are the demand and the supply. The demand consists of the incremental, effective MW required to relieve the constraint. The supply consists of the incremental, effective MW of supply available to relieve the constraint at a distribution factor (DFAX) greater than, or equal to, the DFAX used by PJM in operations.[8] For purposes of the test, incremental effective MW are attributed to specific suppliers on the basis of their control of the assets in question. Generation capacity controlled directly or indirectly through affiliates or through contracts with third parties are attributed to a single supplier.

The supply directly included as relevant to the market in the three pivotal supplier test consists of the incremental, effective MW of supply that are available at a price less than, or equal to, 1.5 times the clearing price (P_c) that would result from the intersection of demand (constraint relief required) and the incremental supply available to resolve the constraint. This measure of supply is termed the relevant effective supply (*S*) in the market for the relief of the constraint in question. In every case, incrementally available supply is

8 A unit's contribution toward effective, incrementally available supply is based on the DFAX of the unit relative to the constraint and the unit's incrementally available capacity over current load levels, to the extent that the capacity in question can be made available within an hour of the time the relief will be needed. Effective, incrementally available MW from an unloaded 100 MW 15-minute start combustion turbine (CT) with a DFAX of 0.05 to a constraint would be 5 MW relative to the constraint in question. Effective, incrementally available MW from a 200 MW steam unit, with 100 MW loaded, a 50 MW ramp rate and a DFAX of 0.5 to the constraint would be 25 MW.

measured as incremental effective MW of supply, as shown in Equation L-1, and the clearing price *(P_c)* is defined as shown in Equation L-2:

Equation L-1 Incremental effective MW of supply

$MW \cdot DFAX$; and

Equation L-2 Price of clearing offer

$$P_c = \frac{Offer_c - SMP}{DFAX_c}.$$

To be relevant, the effective offer of incremental supplier *i* must be less than, or equal to, 1.5 times P_c:

Equation L-3 Relevant and effective offer

$$P_{ie} = \frac{Offer_i}{DFAX_i} \leq 1.5 \cdot P_c.$$

Where the relevant, effective incremental supply of supplier *i* is a function of price:

Equation L-4 Relevant and effective supply of supplier i

$$S_i = MW\ (P_{ie}) \cdot DFAX_i.$$

Where S_i is the relevant effective supply (relevant, incremental and effective supply) of supplier *i*, total relevant effective supply (total relevant, incremental and effective supply) for suppliers *i*=1 to n is shown in Equation L-5:

Equation L-5 Total relevant, effective supply

$$S = \sum_{i=1}^{n} S_i.$$

Each effective supplier, from 1 to n, is ranked, from the largest to the smallest relevant effective supply, relative to the constraint for which it is being tested. In the first iteration of the test, the two largest suppliers are combined with the third largest supplier, and this combined supply is subtracted from total relevant effective supply. The resulting net amount of relevant effective supply is divided by the total relief required (*D*). Where *j* defines the supplier being tested in combination with the two largest suppliers (initially the third largest supplier with *j*=3), Equation L-6 shows the formula for the three pivotal supplier metric, i.e., the three pivotal residual supplier index *(RSI3)*:

Equation L-6 Calculating the three pivotal supplier test

$$RSI3_j = \frac{\sum_{i=1}^{n} S_i - \sum_{i=1}^{2} S_i - S_j}{D}.$$

Where j=3, if $RSI3_j$ is less than, or equal to, 1.0, then the three largest suppliers in the market for the relief of the constraint fail the three pivotal supplier test. That is, the three largest suppliers are jointly pivotal for the local market created by the need to relieve the constraint using local, out-of-merit units. If $RSI3_j$ is greater than 1.0, then the three largest potential suppliers of relief MW pass the test and the remaining suppliers (j=4..n) pass the test. In the event of a failure of the three largest suppliers, further iterations of the test are needed, with each subsequent iteration testing a subsequently smaller supplier (j=4..n) in combination with the two largest suppliers. In each iteration, if $RSI3_j$ is less than 1.0, it indicates that the tested supplier, in combination with the two largest suppliers, has failed the test. Iterations of the test continue until the combination of the two largest suppliers and a supplier j result in $RSI3_j$ greater than 1.0. When the result of this process is that $RSI3_j$ is greater than 1.0, the remaining suppliers pass the test.

If a supplier fails the test for a constraint, units that are part of a supplier's relevant effective supply with respect to a constraint can have their offers capped at cost plus 10 percent, or cost plus relevant adders for frequently mitigated units and associated units. Offer capping only occurs to the extent that the units of this supplier's relevant, effective supply are offered at greater than cost plus 10 percent and are actually dispatched to contribute to the relief of the constraint in question.

APPENDIX M – GLOSSARY

Active load management (ALM)	Retail customer load that can be interrupted at the request of PJM. Such a PJM request is considered an emergency action and is implemented prior to a voltage reduction. ALM derives an ALM credit in the accounted-for-obligation. ALM was replaced under the RPM Capacity Market.
Aggregate	Combination of buses or bus prices.
Ancillary service	Those services necessary to support the transmission of capacity and energy from resources to loads while, in accordance with good utility practice, maintaining reliable operation of the transmission provider's transmission system.
Area control error (ACE)	Area control error (ACE) is a real-time metric used by PJM operators to measure the imbalance between load and generation. ACE is the instantaneous MW imbalance between generation and load plus net interchange.
Associated unit (AU)	A unit that is located at the same site as a frequently mitigated unit (FMU) and which has identical electrical and economic impacts on the transmission system as an FMU but which does not qualify for FMU status.
Auction Revenue Right (ARR)	A financial instrument entitling its holder to auction revenue from Financial Transmission Rights (FTRs) based on locational marginal price (LMP) differences across a specific path in the Annual FTR Auction.
Automatic generation control (AGC)	An automatic control system comprised of hardware and software. Hardware is installed on generators allowing their output to be automatically adjusted and monitored by an external signal and software is installed facilitating that output adjustment.
Average hourly LMP	An LMP calculated by averaging hourly LMP with equal hourly weights; also referred to as a simple average hourly LMP.
Balancing energy market	Energy that is generated and financially settled during real time.
Bilateral agreement	An agreement between two parties for the sale and delivery of a service.
Black start unit	A generating unit with the ability to go from a shutdown condition to an operating condition and start delivering power without assistance from the transmission system.

Bottled generation	Economic generation that cannot be dispatched because of local operating constraints.
Burner tip fuel price	The cost of fuel delivered to the generator site equaling the fuel commodity price plus all transportation costs.
Bus	An interconnection point.
Capacity credit	An entitlement to a specified number of MW of unforced capacity from a capacity resource for the purpose of satisfying capacity obligations imposed in the Capacity Credit Market (CCM) under the Reliability Assurance Agreement (RAA).
Capacity deficiency rate (CDR)	The capacity deficiency rate is based on the annual carrying charges for a new combustion turbine, installed and connected to the transmission system. To express the CDR in terms of unforced capacity, it must be further divided by the quantity 1 minus the EFORd.
Capacity queue	A collection of Regional Transmission Expansion Planning (RTEP) capacity resource project requests received during a particular timeframe and designating an expected in-service date.
Combined cycle (CC)	A generating unit generally consisting of one or more gas-fired turbines and a heat recovery steam generator. Electricity is produced by a gas turbine whose exhaust is recovered to heat water, yielding steam for a steam turbine that produces still more electricity.
Combustion turbine (CT)	A generating unit in which a combustion turbine engine is the prime mover.
Control zone	An area within the PJM Control Area, as set forth in the PJM Open Access Transmission Tariff and the RAA. Schedule 16 of the RAA defines the distinct zones that comprise the PJM Control Area.
Decrement bids (DEC)	Financial bid to purchase a defined MW level of energy up to a specified LMP, above which the bid is zero.
Dispatch rate	Control signal, expressed in dollars per MWh, calculated by PJM and transmitted continuously and dynamically to generating units to direct the output level of all generation resources dispatched by PJM.
Disturbance control standard	A NERC-defined metric measuring the ability of a control area to return area control error (ACE) either to zero or to its predisturbance level after a disturbance such as a generator or transmission loss.

Eastern Prevailing Time (EPT)	Eastern Prevailing Time (EPT) is equivalent to Eastern Standard Time (EST) or Eastern Daylight Time (EDT) as is in effect from time to time.
Economic generation	Units producing energy at an offer price less than, or equal to, LMP.
End-use customer	Any customer purchasing electricity at retail.
Equivalent availability factor (EAF)	The equivalent availability factor is the proportion of hours in a year that a unit is available to generate at full capacity.
Equivalent demand forced outage rate (EFORd)	The equivalent demand forced outage rate (EFORd) (generally referred to as the forced outage rate) is a measure of the probability that a generating unit will fail, either partially or totally, to perform when it is needed to operate.
Equivalent forced outage factor (EFOF)	The equivalent forced outage factor is the proportion of hours in a year that a unit is unavailable because of forced outages.
Equivalent maintenance outage factor (EMOF)	The equivalent maintenance outage factor is the proportion of hours in a year that a unit is unavailable because of maintenance outages.
Equivalent planned outage factor (EPOF)	The equivalent planned outage factor is the proportion of hours in a year that a unit is unavailable because of planned outages.
External resource	A resource located outside metered PJM boundaries.
Financial Transmission Right (FTR)	A financial instrument entitling the holder to receive revenues based on transmission congestion measured as hourly energy LMP differences in the PJM Day-Ahead Energy Market across a specific path.
Firm point-to-point transmission	Firm transmission service that is reserved and/or scheduled between specified points of receipt and delivery.
Firm transmission	Transmission service that is intended to be available at all times to the maximum extent practicable. Service availability is, however, subject to an emergency, an unanticipated failure of a facility or other event.
Fixed-demand bid	Bid to purchase a defined MW level of energy, regardless of LMP.
Frequently mitigated unit (FMU)	A unit that was offer capped for more than a defined proportion of its real-time run hours in the most recent 12-month period. FMU thresholds are 60 percent, 70 percent and 80 percent of run hours. Such units are permitted a defined adder to their cost-based offers in place of the usual 10 percent adder.

Generation offers	Schedules of MW offered and the corresponding offer price.
Generation owner	A PJM member that owns or leases, with rights equivalent to ownership, facilities for generation of electric energy that are located within PJM.
Gross deficiency	The sum of all companies' individual capacity deficiency, or the shortfall of unforced capacity below unforced capacity obligation. The term is also referred to as accounted-for deficiency.
Gross excess	The amount by which a load-serving entity's (LSE's) unforced capacity exceeds its accounted-for obligation. The term is referred to as "Accounted-for Excess" in the "Manual 35: Definitions and Acronyms."
Gross export volume (energy)	The sum of all export transaction volume (MWh).
Gross import volume (energy)	The sum of all import transaction volume (MWh).
Gigawatt (GW)	A unit of power equal to 1,000 megawatts.
Gigawatt-day	One GW of energy flow or capacity for one day.
Gigawatt-hour (GWh)	One GWh is a gigawatt produced or consumed for one hour.
Herfindahl-Hirschman Index (HHI)	HHI is calculated as the sum of the squares of the market share percentages of all firms in a market.
Hertz (Hz)	Electricity system frequency is measured in hertz.
HRSG	Heat recovery steam generator. An air-to-steam heat exchanger installed on combined-cycle generators.
Increment offers (INC)	Financial offers in the Day-Ahead Energy Market to supply specified amounts of MW at, or above, a given price.
Inframarginal unit	A unit that is operating, with an accepted offer that is less than the clearing price.
Installed capacity	Installed capacity is the as-tested maximum net dependable capability of the generator, measured in MW.
Load	Demand for electricity at a given time.
Load-serving entity (LSE)	Load-serving entities provide electricity to retail customers. Load-serving entities include traditional distribution utilities and new entrants into the competitive power market.
Lost opportunity cost (LOC)	The difference in net compensation from the Energy Market between what a unit receives when providing regulation or synchronized reserve and what it would have received for providing energy output.

Marginal unit	The last generation unit to supply power under a merit order dispatch system.
Market-clearing price	The price that is paid by all load and paid to all suppliers.
Market participant	A PJM market participant can be a market supplier, a market buyer or both. Market buyers and market sellers are members that have met creditworthiness standards as established by the PJM Office of the Interconnection.
Market user interface	A thin client application allowing generation sellers to provide and to view generation data, including bids, unit status and market results.
Mean	The arithmetic average.
Median	The midpoint of data values. Half the values are above and half below the median.
Megawatt (MW)	A unit of power equal to 1,000 kilowatts.
Megawatt-day	One MW of energy flow or capacity for one day.
Megawatt-hour (MWh)	One MWh is a megawatt produced or consumed for one hour.
Megawatt-year	One MW of energy flow or capacity for one calendar year.
Monthly CCM	The capacity credits cleared each month through the PJM Monthly Capacity Credit Market (CCM).
Multimonthly CCM	The capacity credits cleared through PJM Multimonthly Capacity Credit Market (CCM).
Net excess (capacity)	The net of gross excess and gross deficiency, therefore the total PJM capacity resources in excess of the sum of load-serving entities' obligations.
Net exchange (capacity)	Capacity imports less exports.
Net interchange (energy)	Gross import volume less gross export volume in MWh.
Noneconomic generation	Units producing energy at an offer price greater than the LMP.
North American Electric Reliability Council (NERC)	A voluntary organization of U.S. and Canadian utilities and power pools established to assure coordinated operation of the interconnected transmission systems.

Obligation	The sum of all load-serving entities' unforced capacity obligations as determined by summing the weather-adjusted summer coincident peak demands for the prior summer, netting out ALM credits, adding a reserve margin and adjusting for the system average forced outage rate.
Off peak	For the PJM Energy Market, off-peak periods are all NERC holidays (i.e., New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, Christmas Day) and weekend hours plus weekdays from the hour ending at midnight until the hour ending at 0700.
On peak	For the PJM Energy Market, on-peak periods are weekdays, except NERC holidays (i.e., New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, Christmas Day) from the hour ending at 0800 until the hour ending at 2300.
PJM member	Any entity that has completed an application and satisfies the requirements of the PJM Board of Managers to conduct business with PJM, including transmission owners, generating entities, load-serving entities and marketers.
PJM planning year	The calendar period from June 1 through May 31.
Price duration curve	A graphic representation of the percent of hours that a system's price was at or below a given level during the year.
Price-sensitive bid	Purchases of a defined MW level of energy only up to a specified LMP. Above that LMP, the load bid is zero.
Primary operating interfaces	Primary operating interfaces are typically defined by a cross section of transmission paths or single facilities which affect a wide geographic area. These interfaces are modeled as constraints whose operating limits are respected in performing dispatch operations.
Regional Transmission Expansion Planning Protocol	The process by which PJM recommends specific transmission facility enhancements and expansions based on reliability and economic criteria.
Reliability*First* Corporation	Reliability*First* Corporation (RFC) began operation January 1, 2006, as the successor to three other reliability organizations: the Mid-Atlantic Area Council (MAAC), the East Central Area Coordination Agreement (ECAR), and the Mid-American Interconnected Network (MAIN). PJM is registered with RFC to comply with its reliability standards for balancing authority (BA), planning coordinator (PC), reliability coordinator (RC), resource planner (RP), transmission operator (TOP), transmission planner (TP) and transmission service provider (TSP).
Selective catalytic reduction (SCR)	NO_X reduction equipment usually installed on combined-cycle generators.

Self-scheduled generation	Units scheduled to run by their owners regardless of system dispatch signal. Self-scheduled units do not follow system dispatch signal and are not eligible to set LMP. Units can be submitted as a fixed block of MW that must be run, or as a minimum amount of MW that must run plus a dispatchable component above the minimum.
Shadow price	The constraint shadow price represents the incremental reduction in congestion cost achieved by relieving a constraint by 1 MW. The shadow price multiplied by the flow (in MW) on the constrained facility during each hour equals the hourly gross congestion cost for the constraint.
Sources and sinks	Sources are the origins or the injection end of a transmission transaction. Sinks are the destinations or the withdrawal end of a transaction.
Spot market	Transactions made in the Real-Time and Day-Ahead Energy Market at hourly LMP.
Static Var compensator	A static Var compensator (SVC) is an electrical device for providing fast-acting, reactive power compensation on high-voltage electricity transmission networks.
Synchronized reserve	Reserve capability which is required in order to enable an area to restore its tie lines to the pre-contingency state within 10 minutes of a contingency that causes an imbalance between load and generation. During normal operation, these reserves must be provided by increasing energy output on electrically synchronized equipment, by reducing load on pumped storage hydroelectric facilities or by reducing the demand by demand-side resources. During system restoration, customer load may be classified as synchronized reserve.
System installed capacity	System total installed capacity measures the sum of the installed capacity (in installed, not unforced, terms) from all internal and qualified external resources designated as PJM capacity resources.
System lambda	The cost to the PJM system of generating the next unit of output.
Temperature-humidity index (THI)	A temperature-humidity index (THI) gives a single, numerical value reflecting the outdoor atmospheric conditions of temperature and humidity as a measure of comfort (or discomfort) during warm weather. THI is defined as: THI = $T_d - (0.55 - 0.55RH) * (T_d - 58)$ where T_d is the dry-bulb temperature and *RH* is the percentage of relative humidity.

Unforced capacity	Installed capacity adjusted by forced outage rates.
Wheel-through	An energy transaction flowing through a transmission grid whose origination and destination are outside of the transmission grid.
Zone	See “Control zone” (above).

APPENDIX N – LIST OF ACRONYMS

ACE	Area control error
ACR	Avoidable cost rate
AECI	Associated Electric Cooperative Inc.
AECO	Atlantic City Electric Company
AEG	Alliant Energy Corporation
AEP	American Electric Power Company, Inc.
AGC	Automatic generation control
ALM	Active load management
AMIL	Ameren - Illinois
AMRN	Ameren
AP	Allegheny Power Company
ARR	Auction Revenue Right
ARS	Automatic reserve sharing
ATC	Available transfer capability
AU	Associated unit
BAAL	Balancing authority ACE limit
BGE	Baltimore Gas and Electric Company
BGS	Basic generation service
BME	Balancing market evaluation
Btu	British thermal unit

CAISO	California Independent System Operator
C&I	Commercial and industrial customers
CBL	Customer base line
CC	Combined cycle
CCM	Capacity Credit Market
CDR	Capacity deficiency rate
CDTF	Cost Development Task Force
CETL	Capacity emergency transfer limit
CETO	Capacity emergency transfer objective
CF	Coordinated flowgate under the Joint Operating Agreement between PJM and the Midwest Independent Transmission System Operator, Inc.
CILC	Central Illinois Light Company Interface
CILCO	Central Illinois Light Company
CIN	Cinergy Corporation
CLMP	Congestion component of LMP
ComEd	The Commonwealth Edison Company
Con Edison	The Consolidated Edison Company
CONE	Cost of new entry
CP	Pulverized coal-fired generator
CPL	Carolina Power & Light Company
CPS	Control performance standard
CSP	Curtailment service provider

CT	Combustion turbine
CTR	Capacity transfer right
DAY	The Dayton Power & Light Company
DCS	Disturbance control standard
DEC	Decrement bid
DFAX	Distribution factor
DL	Diesel
DLCO	Duquesne Light Company
DPL	Delmarva Power & Light Company
DPLN	Delmarva Peninsula north
DPLS	Delmarva Peninsula south
DR	Demand response
DSR	Demand-side response
DUK	Duke Energy Corp.
EAF	Equivalent availability factor
ECAR	East Central Area Reliability Council
EDC	Electricity distribution company
EDT	Eastern Daylight Time
EEA	Emergency energy alert
EES	Enhanced Energy Scheduler
EFOF	Equivalent forced outage factor

EFORd	Equivalent demand forced outage rate
EHV	Extra-high-voltage
EKPC	East Kentucky Power Cooperative, Inc.
EMAAC	Eastern Mid-Atlantic Area Council
EMOF	Equivalent maintenance outage factor
EPOF	Equivalent planned outage factor
EPT	Eastern Prevailing Time
EST	Eastern Standard Time
ExGen	Exelon Generation Company, L.L.C.
FE	FirstEnergy Corp.
FERC	The United States Federal Energy Regulatory Commission
FMU	Frequently mitigated unit
FPA	Federal Power Act
FPR	Forecast pool requirement
FRR	Fixed resource requirement
FTR	Financial Transmission Right
GE	General Electric Company
GW	Gigawatt
GWh	Gigawatt-hour
HHI	Herfindahl-Hirschman Index
HRSG	Heat recovery steam generator

HVDC	High-voltage direct current
Hz	Hertz
ICAP	Installed capacity
IDC	Interchange distribution calculator
ILR	Interruptible load for reliability
INC	Increment offer
IP	Illinois Power Company
IPL	Indianapolis Power & Light Company
IPP	Independent power producer
IRM	Installed reserve margin
IRR	Internal rate of return
ISA	Interconnection service agreement
ISO	Independent system operator
JCPL	Jersey Central Power & Light Company
JOA	Joint operating agreement
JOU	Jointly owned units
JRCA	Joint Reliability Coordination Agreement
LAS	PJM Load Analysis Subcommittee
LDA	Locational deliverability area
LGEE	LG&E Energy, L.L.C.
LM	Load management

LMP	Locational marginal price
LOC	Lost opportunity cost
LSE	Load-serving entity
MAAC	Mid-Atlantic Area Council
MAAC+APS	Mid-Atlantic Area Council plus the Allegheny Power System
MACRS	Modified accelerated cost recovery schedule
MAIN	Mid-America Interconnected Network, Inc.
MAPP	Mid-Continent Area Power Pool
MCP	Market-clearing price
MEC	MidAmerican Energy Company
MECS	Michigan Electric Coordinated System
Met-Ed	Metropolitan Edison Company
MICHFE	The pricing point for the Michigan Electric Coordinated System and FirstEnergy control areas
Midwest ISO	Midwest Independent Transmission System Operator, Inc.
MIL	Mandatory interruptible load
Mon Power	Monongahela Power
MMU	PJM Market Monitoring Unit
MP	Market participant
MUI	Market user interface
MW	Megawatt
MWh	Megawatt-hour

NAESB	North American Energy Standards Board
NERC	North American Electric Reliability Council
NICA	Northern Illinois Control Area
NIPSCO	Northern Indiana Public Service Company
NNL	Network and native load
NO_x	Nitrogen oxides
NUG	Non-utility generator
NYISO	New York Independent System Operator
OA	Amended and Restated Operating Agreement of PJM Interconnection, L.L.C.
OASIS	Open Access Same-Time Information System
OATI	Open Access Technology International, Inc.
OATT	PJM Open Access Transmission Tariff
ODEC	Old Dominion Electric Cooperative
OEM	Original equipment manufacturer
OI	PJM Office of the Interconnection
Ontario IESO	Ontario Independent Electricity System Operator
OVEC	Ohio Valley Electric Corporation
PAR	Phase angle regulator
PE	PECO zone
PEC	Progress Energy Carolinas, Inc.
PECO	PECO Energy Company

PENELEC	Pennsylvania Electric Company
Pepco	Formerly Potomac Electric Power Company or PEPCO
PJM	PJM Interconnection, L.L.C.
PJM/AEPNI	The interface between the American Electric Power Control Zone and Northern Illinois
PJM/AEPPJM	The interface between the American Electric Power Control Zone and PJM
PJM/AEPVP	The single interface pricing point formed in March 2003 from the combination of two previous interface pricing points: PJM/American Electric Power Company, Inc. and PJM/Dominion Resources, Inc.
PJM/AEPVPEXP	The export direction of the PJM/AEPVP interface pricing point
PJM/AEPVPIMP	The import direction of the PJM/AEPVP interface pricing point
PJM/ALTE	The interface between PJM and the eastern portion of the Alliant Energy Corporation's control area
PJM/ALTW	The interface between PJM and the western portion of the Alliant Energy Corporation's control area
PJM/AMRN	The interface between PJM and the Ameren Corporation's control area
PJM/CILC	The interface between PJM and the Central Illinois Light Company's control area
PJM/CIN	The interface between PJM and the Cinergy Corporation's control area
PJM/CPLE	The interface between PJM and the eastern portion of the Carolina Power & Light Company's control area
PJM/CPLW	The interface between PJM and the western portion of the Carolina Power & Light Company's control area
PJM/CWPL	The interface between PJM and the City Water, Light & Power's (City of Springfield, IL) control area

PJM/DLCO	The interface between PJM and the Duquesne Light Company's control area
PJM/DUK	The interface between PJM and the Duke Energy Corp.'s control area
PJM/EKPC	The interface between PJM and the Eastern Kentucky Power Corporation's control area
PJM/FE	The interface between PJM and the FirstEnergy Corp.'s control area
PJMICC	PJM Industrial Customer Coalition
PJM/IP	The interface between PJM and the Illinois Power Company's control area
PJM/IPL	The interface between PJM and the Indianapolis Power & Light Company's control area
PJM/LGEE	The interface between PJM and the Louisville Gas and Electric Company's control area
PJM/MEC	The interface between PJM and MidAmerican Energy Company's control area
PJM/MECS	The interface between PJM and the Michigan Electric Coordinated System's control area
PJM/MISO	The interface between PJM and the Midwest Independent System Operator
PJM/NIPS	The interface between PJM and the Northern Indiana Public Service Company's control area
PJM/NYIS	The interface between PJM and the New York Independent System Operator
PJM/Ontario IESO	PJM/Ontario IESO pricing point
PJM/OVEC	The interface between PJM and the Ohio Valley Electric Corporation's control area
PJM/TVA	The interface between PJM and the Tennessee Valley Authority's control area

PJM/VAP	The interface between PJM and the Dominion Virginia Power's control area
PJM/WEC	The interface between PJM and the Wisconsin Energy Corporation's control area
PMMS	Preliminary market structure screen
PNNE	PENELEC's northeastern subarea
PNNW	PENELEC's northwestern subarea
PPL	PPL Electric Utilities Corporation
PSE&G	Public Service Electric and Gas Company (a wholly owned subsidiary of PSEG)
PSEG	Public Service Enterprise Group
PSN	PSEG north
PSNC	PSEG northcentral
RAA	Reliability Assurance Agreement among Load-Serving Entities
RCIS	Reliability Coordinator Information System
RECO	Rockland Electric Company zone
RFC	Reliability*First* Corporation
RMCP	Regulation market-clearing price
RPM	Reliability Pricing Model
RSI	Residual supply index
RSI_x	Residual supply index, using "x" pivotal suppliers
RTC	Real-time commitment
RTEP	Regional Transmission Expansion Plan

RTO	Regional transmission organization
SCPA	Southcentral Pennsylvania subarea
SCR	Selective catalytic reduction
SEPJM	Southeastern PJM subarea
SERC	Southeastern Electric Reliability Council
SFT	Simultaneous feasibility test
SMECO	Southern Maryland Electric Cooperative
SMP	System marginal price
SNJ	Southern New Jersey
SO_2	Sulfur dioxide
SOUTHEXP	South Export pricing point
SOUTHIMP	South Import pricing point
SPP	Southwest Power Pool, Inc.
SPREGO	Synchronized reserve and regulation optimizer (market-clearing software)
SRMCP	Synchronized reserve market-clearing price
STD	Standard deviation
SVC	Static Var compensator
SWMAAC	Southwestern Mid-Atlantic Area Council
TEAC	Transmission Expansion Advisory Committee
THI	Temperature-humidity index
TLR	Transmission loading relief

TPS	Three pivotal supplier
TVA	Tennessee Valley Authority
UCAP	Unforced capacity
UDS	Unit dispatch system
UGI	UGI Utilities, Inc.
UPF	Unit participation factor
VACAR	Virginia and Carolinas Area
VAP	Dominion Virginia Power
VOM	Variable operation and maintenance expense
VRR	Variable resource requirement
WEC	Wisconsin Energy Corporation