2007 State of the Market Report

VOLUME 1: INTRODUCTION

MARKET MONITORING UNIT
MARCH 11, 2008

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).

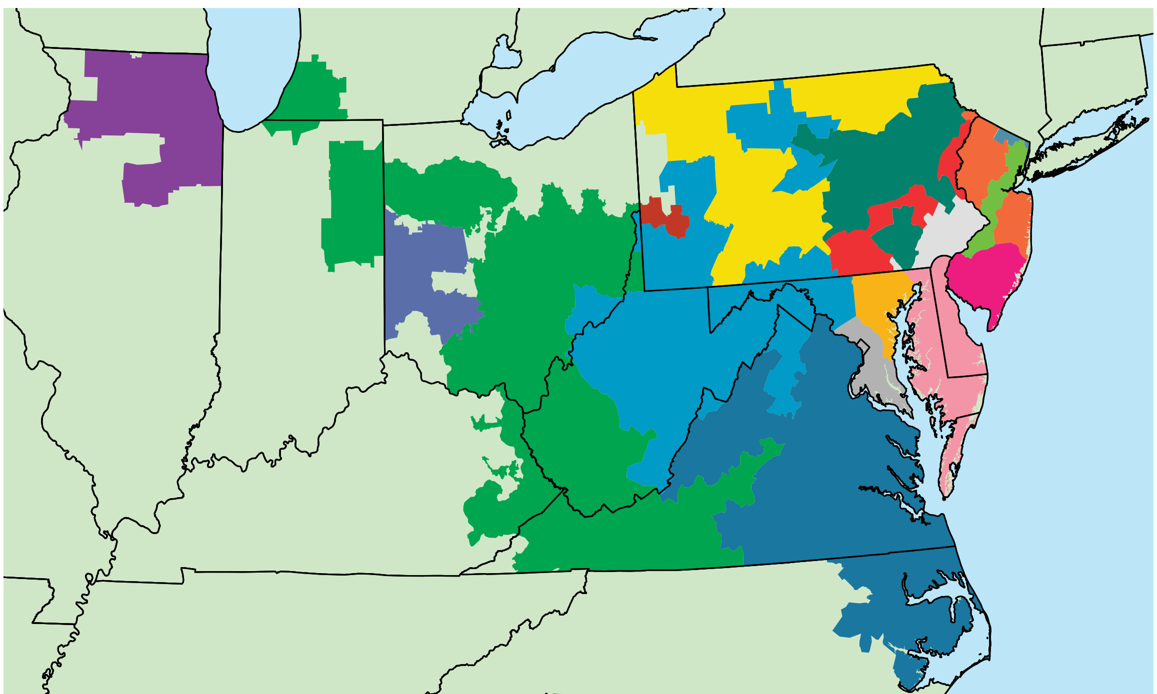
2 96 FERC ¶ 61,061 (2001).

TABLE OF CONTENTS

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. (See Figure 1-1.)[1] As part of that function, PJM coordinates and directs the operation of the transmission grid and plans transmission expansion improvements to maintain grid reliability in this region.

Figure 1-1 PJM's footprint and its zones



Legend

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

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

PJM Market Background

PJM operates the Day-Ahead Energy Market, the Real-Time Energy Market, the 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.

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

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."

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

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).

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 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).

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 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. The MMU concludes that the PJM Energy Market results were competitive in 2007.

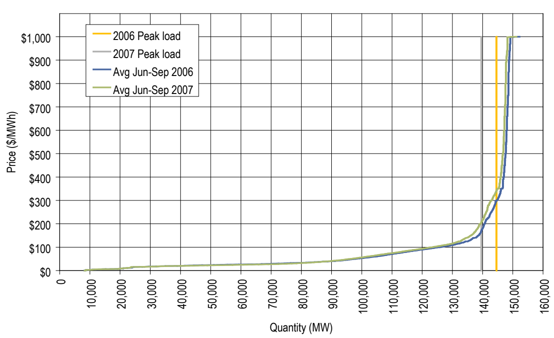
PJM markets are designed to promote competitive outcomes derived from the interaction of supply and demand in each of the PJM markets. Market design itself is the primary means of achieving and promoting competitive outcomes in PJM markets. One of the MMU's primary goals is to identify actual or potential market design flaws.[8] PJM's market power mitigation goals have focused on market designs that promote competition (a structural basis for competitive outcomes) and on limiting market power mitigation to instances where 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.

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

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.[9] 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.[10]

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



- **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.[11] The 2007 peak load was 5,216 MW, or 3.6 percent, lower than the 2006 peak load. (See Figure 1-2.)

- **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. (See Table 1-1.)

- **Local Market Structure.** A summary of the results of PJM's application of the three pivotal supplier test is presented for all constraints which occurred for 100 or more hours during calendar year 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.

9 Calculated values shown in the *2007 State of the Market Report*, Volume 1, "Introduction" are based on unrounded, underlying data and may differ from calculations based on the rounded values shown in tables.

10 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.

11 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).

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.

Table 1-1 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%

- 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.

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 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.[12] 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."[13] 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."[14] 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 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

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

13 110 FERC ¶ 61,053 (2005).

14 110 FERC ¶ 61,053 (2005).

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.

Table 1-2 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%

Energy Market, Part 2

The MMU analyzed measures of PJM Energy Market structure, participant conduct and market performance for 2007. 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.

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 RPM construct. The results from 2007 mark a reversal of the trend from the prior eight-year period, 1999 to 2006. (See Table 1-3.) The increased net revenues in 2007 were the result of higher locational energy prices and of much higher locational capacity prices.[15] 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 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. While the PJM average net revenue in 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

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

	CT		CC		CP	
	Economic Dispatch Net Revenue	20-Year Levelized Fixed Cost	Economic Dispatch Net Revenue	20-Year Levelized Fixed Cost	Economic Dispatch Net Revenue	20-Year Levelized Fixed Cost
1999	$74,537	$72,207	$100,700	$93,549	$118,022	$208,247
2000	$30,946	$72,207	$47,592	$93,549	$134,564	$208,247
2001	$63,462	$72,207	$86,670	$93,549	$129,271	$208,247
2002	$28,260	$72,207	$52,272	$93,549	$112,131	$208,247
2003	$10,566	$72,207	$35,591	$93,549	$169,509	$208,247
2004	$8,543	$72,207	$35,785	$93,549	$133,124	$208,247
2005	$10,437	$72,207	$40,817	$93,549	$228,430	$208,247
2006	$14,948	$80,315	$49,529	$99,230	$182,461	$267,792
2007	$48,530	$90,656	$100,809	$143,600	$277,284	$359,750
Avg.	$32,248	$75,158	$61,085	$99,741	$164,977	$231,697

15 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.

natural gas; 18.9 percent was nuclear; 6.5 percent was oil; 4.5 percent was hydroelectric; and 0.4 percent was solid waste.

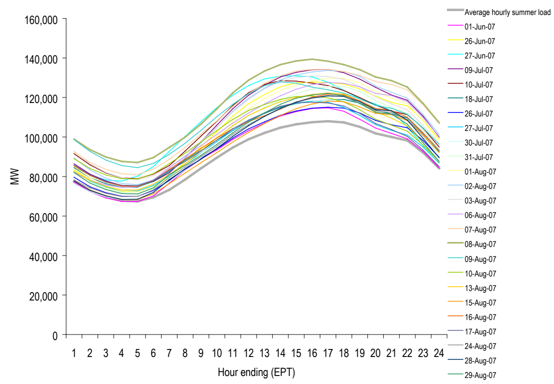
- Generation Fuel Mix. During 2007, coal provided 55.3 percent, nuclear 33.9 percent, natural gas 7.7 percent, oil 0.5 percent, hydroelectric 1.7 percent, solid waste 0.7 percent and wind 0.2 percent of total generation.

- 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.[16] 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.

Figure 1-3 High-load day hourly load and summer average hourly load: June 2007 through August 2007



- 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.[17] 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.

- 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

16 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.

17 114 FERC ¶ 61,076 (2006).

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.

Table 1-4 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%

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.

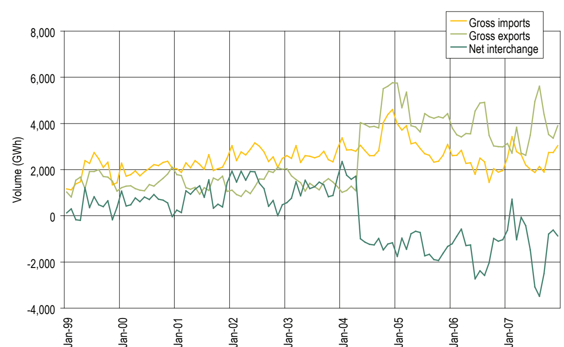
Interchange Transactions

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.

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.[18] Gross monthly import volumes averaged 2,500 GWh while gross monthly exports averaged 3,689 GWh. (See Figure 1-4.)

Figure 1-4 PJM scheduled import and export transaction volume history: Calendar years 1999 to 2007



- **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

18 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.

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.

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).[19] 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.[20]
  - PJM, Midwest ISO and TVA Joint Reliability Coordination Agreement.[21] 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.[22] 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.
  - PJM and Virginia and Carolinas Area (VACAR) South Reliability Coordination Agreement.[23] 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

19 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).

20 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).

21 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).

22 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).

23 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).

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.[24] 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.[25]

- 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.

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 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

24 111 FERC ¶ 61,228 (2005).

25 FERC Order Denying Rehearing, Order, Docket No. EL02-23 (August 15, 2007).

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 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.

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.

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.[26] 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.

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.[27] The CCM consisted of the Daily, Interval, Monthly and Multimonthly CCM.[28] 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.

26 See the *2007 State of the Market Report*, Volume II, Appendix M, "Glossary" and Appendix N, "Acronyms" for definitions of PJM Capacity Market terms.

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

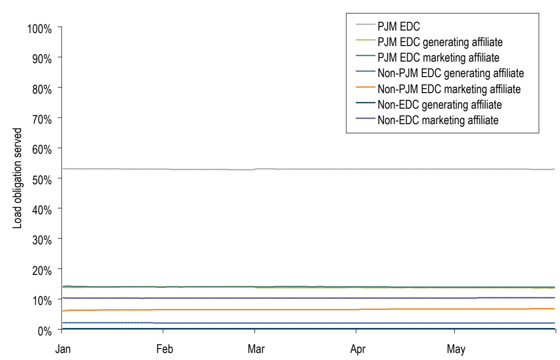
28 PJM defined three intervals for its CCM. The first interval extended for five months and ran from January through May. The second interval extended for four months and ran from June through September. The third interval extended for three months and ran from October through December.

Market Structure

- Supply. Unforced capacity remained relatively constant in the CCM in January through May 2007 compared to 2006.[29] Average unforced capacity increased by 377 MW or 0.2 percent to 152,859 MW. 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. (See Figure 1-5.)

Figure 1-5 PJM Capacity Market load obligation served (Percent): January through May 2007



- 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

29 For information on the CCM during 2006, see the *2006 State of the Market Report*, Volume II, Section 5, "Capacity Market."

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.

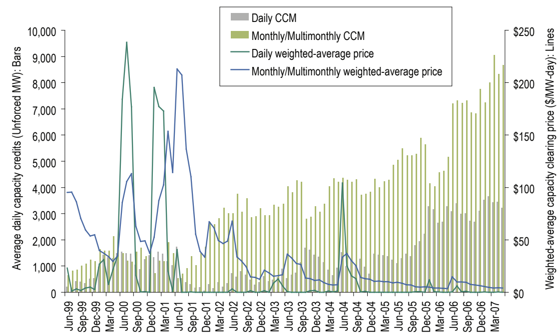
- Active Load Management (ALM). In January through May 2007, ALM credits in the PJM CCM averaged 1,677 MW, down 151 MW (8.3 percent) from 1,828 MW in 2006.

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.

Figure 1-6 PJM Daily and Monthly/Multimonthly CCM performance: June 1999 through May 2007



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.[30] 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,

30 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.

prices are locational and may vary depending on transmission constraints.[31] 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.[32] 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.

Table 1-5 PJM capacity summary (MW): January 1, 2007, through June 1, 2009

		01-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%
RSI3		0.59	0.61	0.59	0.61	0.60
Pivotal suppliers		1	1	1	1	1

31 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.

32 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).

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.

  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.

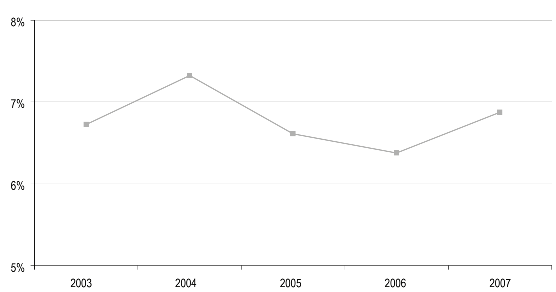
- Southwestern Mid-Atlantic Area Council (SWMAAC). Total internal SWMAAC unforced capacity of 10,352.2 MW includes all generating units and DR that qualified as a PJM capacity resource, excludes external units and reflects owners' modifications to ICAP ratings. There were no imports from outside PJM 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.[33] 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.[34]

Figure 1-7 Trends in the PJM equivalent demand forced outage rate (EFORd): Calendar years 2003 to 2007[35]



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 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

33 Annual EFORd data presented in state of the market reports may be revised based on final data submitted after the publication of the reports.

34 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.

35 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.

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.

Ancillary Service Markets

The FERC defined six ancillary services in Order 888: 1) scheduling, system control and dispatch; 2) reactive supply and voltage control from generation service; 3) regulation and frequency response service; 4) energy imbalance service; 5) operating reserve – synchronized reserve service; and 6) operating reserve – supplemental reserve service.[36] 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.[37] Regulation is provided, independent of economic signal, by generators with a short-term response capability (i.e., less than five minutes) or by 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 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.

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.[38] 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

36 75 FERC ¶ 61,080 (1996).

37 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.

38 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).

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."[39] 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.

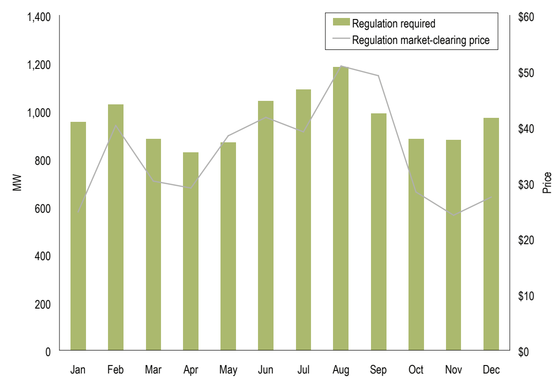
Market Conduct

- 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.

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.

Figure 1-8 Monthly average regulation demand (required) vs. price: Calendar year 2007



Synchronized Reserve Market

In February 2007, PJM restructured the Synchronized Reserve Market.[40] 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

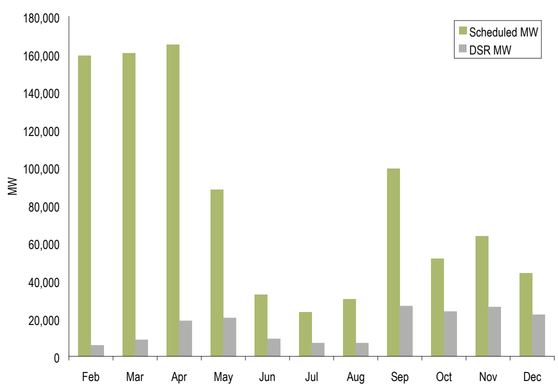
- Supply. During January 2007, the offered and eligible excess supply ratio was 1.28 for the

39 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).

40 In PJM, the term, Synchronized Reserve Market, is used to refer only to Tier 2 synchronized reserve.

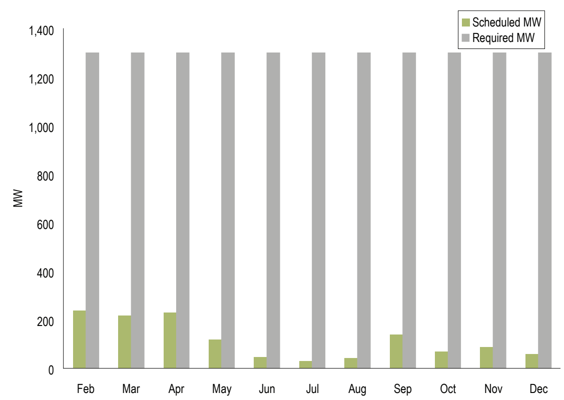
PJM Mid-Atlantic Synchronized Reserve Region and the ratio was 1.24 for the ComEd Synchronized Reserve Control Zone.[41] During February to December 2007, the offered and eligible excess supply ratio was 1.81 for the RFC Synchronized Reserve Zone and the ratio was 1.25 for the Mid-Atlantic Subzone of 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. (See Figure 1-9.)

Figure 1-9 PJM RFC Zone Tier 2 synchronized reserve scheduled MW: February through December 2007



- **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.

Figure 1-10 RFC Synchronized Reserve Zone, Mid-Atlantic Subzone synchronized reserve required vs. scheduled: February through December 2007



- **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.

41 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 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.[42, 43] 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.[44]

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 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.

42 *2005 State of the Market Report* (March 8, 2006), pp. 260-263.

43 *2006 State of the Market Report* (March 8, 2007), p. 247.

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

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.

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.[45] The result is that the price of energy in the constrained area is higher than in the unconstrained area because of the combination of transmission limitations and the cost of local generation. LMPs reflect the price of the lowest-cost resources available to meet loads, taking into account actual delivery constraints imposed by the transmission system. Thus LMP is an efficient way to price energy when transmission constraints exist. Congestion reflects this efficient pricing.

Congestion reflects the underlying features of the power system including the nature and capability of transmission facilities and the cost and geographical distribution of generation facilities. Congestion is neither good nor bad but is a direct measure of the extent to which there are differences in the cost of generation that cannot be equalized because of transmission constraints. A complete set of markets would permit direct competition between investments in transmission and generation. The transmission system provides a physical hedge against congestion. The transmission system is paid for by firm load and, as a result, firm load receives the corollary financial hedge in the form of ARRs and/or FTRs. While the transmission system and, therefore, ARRs/FTRs are not guaranteed to be a complete hedge against congestion, ARRs/FTRs do provide a substantial offset to the cost of congestion to firm load.[46]

45 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.

46 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."

The MMU analyzed congestion and its influence on PJM markets during 2007. In doing so, comparison to 2006 and certain other prior years was required.

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. (See Table 1-6.)

Table 1-6 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%

- 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 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.[47] 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 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.

47 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.

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

Table 1-7 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 1-8 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

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.

Economic Planning Process

- Process Revision. PJM has made multiple filings related to economic metrics for evaluating transmission investments. 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. On October 9, 2007, PJM submitted its compliance filing to address these issues and to provide a formulaic approach for including transmission projects

Table 1-9 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

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.[48] 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.

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.

48 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."

Financial Transmission and Auction Revenue Rights

FTRs and 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 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.[49] 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.

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 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.[50] Market participants can also sell

49 87 FERC ¶ 61,054 (1999).

50 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.”

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 FERC revisions to its Open Access Transmission Tariff (OATT) to improve the credit requirements for FTR market participants.[51] 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.[52] The defaults also raised potential market gaming issues, which were addressed, in part, in a PJM filing.[53] 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.

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

51 *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).

52 *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).

53 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).

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.[54] 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.

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.

54 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).

- **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 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.

Table 1-10 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%

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 addressed, in part, in a PJM filing. These are being investigated.