2008 State of the Market Report for PJM

Volume 1: Introduction

Monitoring Analytics, LLC
Independent Market Monitor for PJM

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PREFACE

Attachment M (PJM Market Monitoring Plan) to the PJM Open Access Transition Tariff provides:

> The Market Monitoring Unit shall prepare and submit contemporaneously to the Commission, the State Commissions, the PJM Board, PJM Management and to the PJM Members Committee, annual state-of-the-market reports on the state of competition within, and the efficiency of, the PJM Markets. In such reports, the Market Monitoring Unit may make recommendations regarding any matter within its purview. These reports shall address, among other things, the extent to which prices in the PJM Markets reflect competitive outcomes, the structural competitiveness of the PJM Markets, the effectiveness of bid mitigation rules, and the effectiveness of the PJM Markets in signaling infrastructure investment. These reports shall include recommendations as to whether changes to the Market Monitoring Unit or the Plan are required.[1]

Accordingly, Monitoring Analytics, LLC, which serves as the Market Monitoring Unit defined in Attachment M, submits this *2008 State of the Market Report*, the eleventh such annual report.

1 PJM, OATT, "Attachment M: PJM Market Monitoring Plan," Fourth Revised Sheet No. 452 (Effective August 1, 2008).

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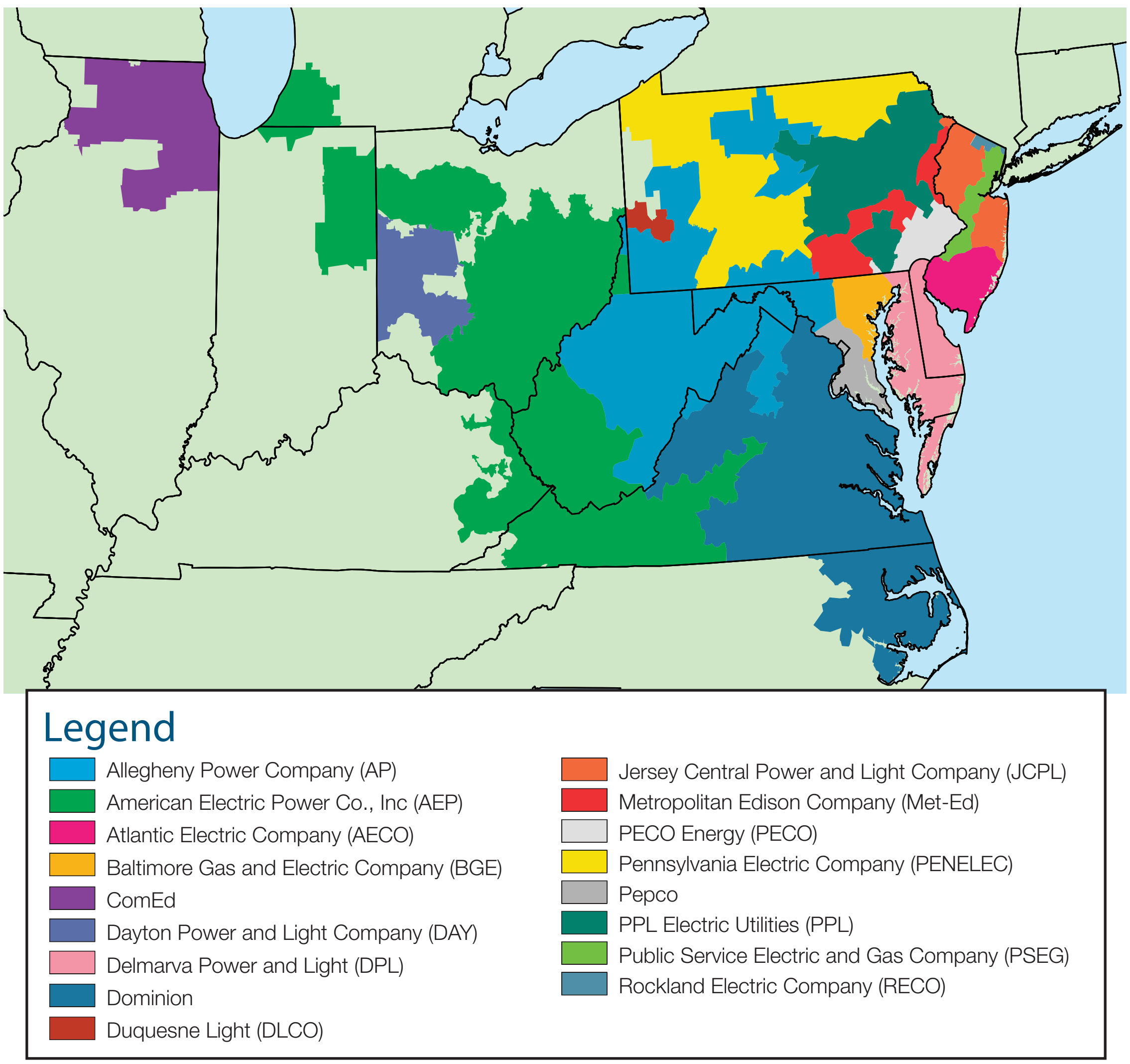
VOLUME 1 – INTRODUCTION

The PJM Interconnection, L.L.C. operates a centrally dispatched, competitive wholesale electric power market that, as of December 31, 2008, had installed generating capacity of 164,895 megawatts (MW) and more than 500 market buyers, sellers and traders of electricity in a region including more than 51 million people in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. (See Figure 1.)[1] 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 PJM's footprint and its 17 control zones



1 See the *2008 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, the Day Ahead Scheduling Reserve (DASR) Market and the Long Term, 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. PJM introduced the RPM Capacity Market effective June 1, 2007. PJM implemented the DASR Market on June 1, 2008.[2]

Volume I of the *2008 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 2008, including market structure, participant behavior and market performance. This report was prepared by and represents the analysis of the independent Market Monitoring Unit (MMU) for PJM.

The MMU concludes that in 2008:

- 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;
- The Day Ahead Scheduling Reserve Market results were competitive; and
- The FTR Auction Market results were competitive.

2 See also the *2008 State of the Market Report*, Volume II, Appendix B, "PJM Market Milestones."

3 Analysis of 2008 market results requires comparison to 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 *2008 State of the Market Report*, Volume II, Appendix A, "PJM Geography."

Recommendations

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

Continued Action

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

  PJM applies the three pivotal supplier test to determine whether local energy markets are structurally competitive. The three pivotal supplier test, as implemented, is consistent with the United States Federal Energy Regulatory Commission's (FERC's) market power tests, encompassed under the delivered price test. The test is a flexible, targeted real-time measure of market structure which replaced the previous mitigation method of offer capping of all units required to relieve a constraint. The application of the three pivotal supplier test successfully limits offer capping in the Energy Market to situations where the local market is structurally noncompetitive and where specific owners have structural market power.

- Retention, application and improvement of the RPM rules included in PJM's 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. RPM rules could be improved by ensuring that capacity payments are made only to units that perform, that the must offer requirement does not permit either physical or economic withholding, that the requirement for capacity resources to make offers in the Day-Ahead Energy Market explicitly require competitive offers and that locational price separation is determined by market fundamentals rather than by rule.

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

In December 2008, PJM implemented the three pivotal supplier test in the Regulation Market, which is expected to successfully address market power issues. The PJM Regulation Market continues to be characterized by structural market power. PJM's application of targeted, flexible, real-time, market power mitigation in the Regulation Market addresses only the hours in which structural market power exists and therefore provides an incentive for the continued development of competition.

- 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 enhancements to rules governing the payment of operating reserve credits to generators and the allocation of operating reserves charges among market participants.

  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. The rules should ensure that market power cannot be exercised to increase operating reserve credits through the use of artificially restrictive unit operating parameters. The rules should base the payment of credits on operating parameters determined by the physical limits of units rather than by offers.

  PJM implemented changes to the operating reserve rules on December 1, 2008. The new operating reserve rules represent positive steps towards the goals of removing the ability to exercise market power and refining the allocation of operating reserves charges to better reflect causal factors.

- 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. There are significant issues with the current approach to measuring demand-side response MW, which is the basis on which program participants are paid. Recent changes to the settlement review process represent clear improvements, but do not go far enough. Additional improvements in measurement and verification methods must be implemented in order to ensure the credibility of PJM demand-side programs. The principal barriers to the further development of demand-side response are in the interface between wholesale and retail markets.

- Reiteration by PJM and the Midwest ISO of their initial recommendation to create an energy schedule tag archive, as this would provide the transparency necessary for a complete loop flow analysis. The MMU recommends that the RTOs request action, and that both NERC and FERC consider taking the action required to make these data available to the RTOs and market monitors to make a full market analysis possible.

PJM continues to face significant loop flows for reasons that continue not to be fully understood because PJM and other balancing authority operators have inadequate access to the data required for a complete analysis of loop flow in the Eastern Interconnection. 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.

- Continued improvement of pricing between PJM and surrounding areas, both market and non market.

  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, as neighboring market areas, should develop market-based congestion management protocols, modeled on the PJM and Midwest ISO JOA, as soon as practicable. 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 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.

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

  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 new spot import rules have incented participant actions to evade the limits and to hoard spot import capability. PJM should reconsider whether the new approach to limiting spot import service is required or whether a return to the prior policy with an explicit system of managing any related congestion is preferable. Up-to congestion service is a market option used to import power to or export power from 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. PJM should consider eliminating all internal PJM buses for use in up-to congestion bidding. In effect, the use of specific buses is equivalent to creating a scheduled transaction which will not equal the actual corresponding power flow.

- 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, but only to the extent consistent with the goal of improving market efficiency and stimulating competition. As an example, PJM should consider posting generator outage data when it becomes available to PJM.

- Continued efforts to incorporate transmission investments into competitive markets.

  PJM has improved its approach to the cost-benefit analysis of transmission investments. PJM should continue to critically evaluate its approach, particularly as it applies to constraints with large and persistent market impacts. Transmission investments have not been fully incorporated into competitive markets. The construction of new transmission facilities, and the lack of existing transmission, can have significant impacts on energy and capacity markets, but there is no market mechanism in place that would require direct competition between transmission and generation to meet loads in an area. PJM has taken a first step towards integrating transmission investments into the market through the use of economic evaluation metrics. Economic evaluation metrics can be used to determine whether there are positive economic benefits associated with an investment in transmission that might warrant the investment even when it is not required for reliability. The goal of transmission planning should ultimately be the incorporation of transmission investment decisions into market driven processes as much as possible.

- Based on the experience of the MMU during its tenth year and its analysis of the PJM markets and based on the outcome of the active, public process that addressed the independence of market monitoring via a public, approved settlement, the MMU is confident that the market monitoring function will continue to be independent, well-organized, well-defined, clear to market participants and consistent with the policies of the FERC.[4, 5]

New Action

- Enhancement of PJM's scarcity pricing rules in the energy market to create regional scarcity signals that reflect stages of scarcity in order to ensure competitive prices when scarcity conditions exist in market regions. Scarcity revenues to generation owners can come entirely from energy markets or they can come from a combination of energy and capacity markets. The approach to scarcity must reflect the fact that revenues in the capacity market are scarcity revenues. If the revenues collected in the RPM market are adequate, it is not essential that a scarcity pricing mechanism exist in the energy market. Nonetheless, it would be preferable to have a scarcity pricing mechanism in the energy market because it provides direct, market-based incentives to load and generation at the margin, as long as the market rules are designed to ensure that scarcity revenues directly offset RPM revenues to prevent double collection of scarcity revenues. The most straightforward way to ensure that such over collection does not occur would be to ensure that capacity resources do not receive scarcity revenues in the

4 PJM. "Open Access Transmission Tariff (OATT)," "Attachment M: PJM Market Monitoring Plan," Fourth Revised Sheet No. 452 (Effective August 1, 2008). 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).

energy market in the first place. The settlements process can remove any scarcity revenues from payments to capacity resources and eliminate the need for a complex, uncertain, after the fact procedure for offsetting scarcity revenues in the capacity market.

The market scarcity 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. More flexible and locational scarcity signals could be implemented via reserve requirements modeled as constraints for scarcity regions, with administrative scarcity penalty factors, in the security constrained dispatch. The level of the penalty factor and the reserve target would be determined by the severity level of the scarcity event. This would provide a means to signal scarcity that is consistent with economic dispatch, consistent with locational pricing and consistent with competitive market outcomes. The trigger for each stage should be based on the level of available operating reserve using a dynamically determined and relevant operating reserve requirement and the progressive use of emergency measures. If implemented using reserve requirement constraints with escalating penalty factors, the scarcity pricing mechanism would eliminate the need to lift offer capping during a scarcity pricing event.

- Implementation of rules governing the definition of final prices to ensure certainty for market participants.

  Changing market prices after the fact should be avoided, even when the reason is a failure to mitigate local market power. Markets depend on prices and market participants depend on the finality and certainty of prices. Ideally, observed prices in real time would be final, but this has not yet been possible in the PJM markets. PJM should consider and implement rules defining when prices are final. This approach to final prices is also consistent with the view that market power mitigation should be done ex ante, whenever possible, to ensure that market price signals are accurate in real time.

- Implementation of improved cost-based data submission to permit better monitoring and better analysis of markets.

  PJM should consider and implement rules requiring the submission of the components of cost-based generation offers. The components should include fuel type and cost, variable operating and maintenance expense and the cost of environmental permits by emission type. Such data will permit better monitoring of generation offers and will permit better analysis of the impacts of environmental regulations on PJM markets.

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 2008, including market size, concentration, residual supply index, price-cost markup, net revenue and price.[6] The MMU concludes that the PJM Energy Market results were competitive in 2008.

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.[7] PJM's market power mitigation goals have focused on market designs that promote competition (a structural basis for competitive outcomes) and on limiting market power mitigation to instances where the market structure is not competitive and thus where market design alone cannot mitigate market power. In the PJM Energy Market, this occurs only in the case of local market power. When a transmission constraint creates the potential for local market power, PJM applies a structural test to determine if the local market is competitive, applies a behavioral test to determine if generator offers exceed competitive levels and applies a market performance test to determine if such generator offers would affect the market price.

Market Structure

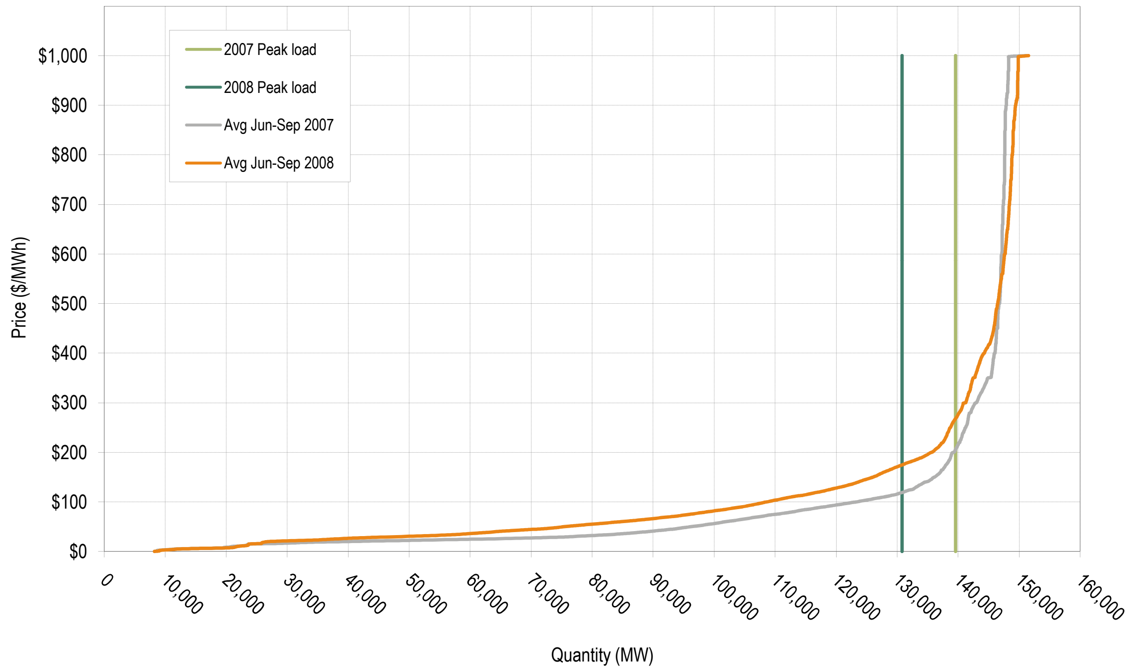
- **Supply.** During the June to September 2008 summer period, the PJM Energy Market received an hourly average of 154,959 MW in supply offers including hydroelectric generation.[8] The summer 2008 average supply offers were 15 MW higher than the summer 2007 average supply of 154,944 MW.

6 Analysis of 2008 market results requires comparison to prior years. During calendar years 2004 and 2005, PJM conducted the phased integration of five control zones: ComEd, American Electric Power (AEP), The Dayton Power & Light Company (DAY), Duquesne Light Company (DLCO) and Dominion. By convention, control zones bear the name of a large utility service provider working within their boundaries. The nomenclature applies to the geographic area, not to any single company. For additional information on the control zones, the integrations, their timing and their impact on the footprint of the PJM service territory, see the *2008 State of the Market Report*, Volume II, Appendix A, "PJM Geography."

7 See PJM. "Open Access Transmission Tariff (OATT)," "Attachment M: Market Monitoring Plan," First Revised Sheet No. 448.05 (Effective August 1, 2008).

8 Calculated values are based on unrounded, underlying data and may differ from calculations based on the rounded values shown in tables.

Figure 2 Average PJM aggregate supply curves: Summers 2007 and 2008



- **Demand.** The PJM system peak load in 2008 was 130,100 MW in the hour ended 1700 EPT on June 9, 2008, while the PJM peak load in 2007 was 139,428 in the hour ended 1600 on August 8, 2007.[9] The 2008 peak load was 9,328 MW, or 6.7 percent, lower than the 2007 peak load.

- **Market Concentration.** Concentration ratios are a summary measure of market share, a key element of market structure. High concentration ratios indicate comparatively smaller numbers of sellers dominating a market, while low concentration ratios mean larger numbers of sellers splitting market sales more equally. High concentration ratios indicate an increased potential for participants to exercise market power, although low concentration ratios do not necessarily mean that a market is competitive or that participants cannot exercise market power. Analysis of the PJM Energy Market indicates moderate market concentration overall. Analyses of supply curve segments indicate moderate concentration in the baseload segment, but high concentration in the intermediate and peaking segments.

- **Local Market Structure and Offer Capping.** Noncompetitive local market structure is the trigger for offer capping. PJM applied a flexible, targeted, real-time approach to offer capping (the three pivotal supplier test) as the trigger for offer capping in 2008. 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 were 0.2 percent in 2008, the same level as 2007. In the Real-Time Energy Market offer-capped unit hours fell from 1.1 percent in 2007 to 1.0 percent in 2008.

9 For the purpose of Volume I and Volume II of the *2008 State of the Market Report*, all hours are presented and all hourly data are analyzed using Eastern Prevailing Time (EPT). See Volume II, Appendix M, "Glossary," for a definition of EPT and its relationship to Eastern Standard Time (EST) and Eastern Daylight Time (EDT).

- **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 2008. The analysis of the application of the three pivotal supplier test to local markets demonstrates that it is working successfully to ensure that owners are not subject to offer capping when the market structure is competitive and to offer cap only pivotal owners when the market structure is noncompetitive.

Table 1 Annual offer-capping statistics: Calendar years 2004 to 2008

	Real Time		Day Ahead	
	Unit Hours Capped	MW Capped	Unit Hours Capped	MW Capped
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%
2008	1.0%	0.2%	0.2%	0.1%

Market Performance: Markup, Load and Locational Marginal Price

- **Markup.** The markup conduct of individual owners and units has an impact on market prices. 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, as such a full redispatch is practically impossible because 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 $2.04 per MWh, or 3 percent. The markup was $3.27 per MWh during peak hours and $.74 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.

- **Load.** On average, PJM real-time load decreased in 2008 by 2.7 percent from 2007, falling from 81,681 MW to 79,515 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 2008 over 2007. The system simple average LMP was 15.3 percent higher in 2008 than in 2007, $66.40 per MWh versus $57.58 per MWh. The load-weighted LMP was 15.4 percent higher in 2008 than in 2007, $71.13 per MWh versus $61.66 per MWh. The fuel-cost-adjusted, load-weighted, average LMP was 16.0 percent lower in 2008 than in 2007, $51.79 per MWh compared to $61.66 per MWh. Fuel costs in 2008 contributed to upward pressure on LMP.

- **Retroactive Change to LMP.** On September 24, 2008, PJM retroactively changed Real-Time LMP for September 4, 2008, for hours ending 15 through 21 and the hour ending 24, and notified PJM members. The largest positive zonal impact was in the Dominion Control Zone, which experienced an average $2.43 per MWh increase as a result of the change, and the largest negative zonal impact occurred in the PECO Control Zone, which experienced an average $2.28 per MWh decrease as a result of the change. The largest positive bus-specific impact occurred at the Mt Laurel 413 KV TX1 bus, in the PSEG Control Zone, which experienced an average $29.86 per MWh increase after the changes, and the largest negative bus-specific impact occurred at the Bonsack 138 KV T1 bus, in the AEP Control Zone, which experienced an average $24.10 per MWh decrease after the changes.

- **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 parent company that serves load, its load could be supplied by any combination of its own generation, net bilateral market purchases and net spot market purchases. In 2008, 14.6 percent of real-time load was supplied by bilateral contracts, 20.1 percent by spot market purchases and 65.2 percent by self-supply. Compared with 2007, reliance on bilateral contracts decreased by 2.0 percentage points; reliance on spot supply increased by 4.2 percentage points; and reliance on self-supply decreased by 2.3 percentage points in 2008.

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 and has resulted in 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. Recent changes to the settlement review process represent clear improvements, but do not go far enough.

  Total demand-side response resources available in PJM on June 9, 2008 (the peak day in 2008), were 4,439.2 MW eligible for capacity credits and 1,898.8 MW eligible for energy payments from the Emergency Load-Response Program and 2,294.7 MW from the Economic Load-Response Program.

Energy Market, Part 1 Conclusion

The MMU analyzed key elements of PJM Energy Market structure, participant conduct and market performance for calendar year 2008, including aggregate supply and demand, concentration ratios, local market concentration ratios, price-cost markup, offer capping, participation in demand-side response programs, loads and prices in this section of the report. The next section continues the analysis of the PJM Energy Market including additional measures of market performance.

Aggregate supply increased by about 15 MW when comparing the summer of 2008 to the summer of 2007 while aggregate peak load decreased by 9,328 MW, modifying the general supply demand balance from 2007 with a corresponding impact on peak Energy Market prices. Overall load was also lower than in 2007. Market concentration levels remained moderate and average markup decreased. This relationship between supply and demand, regardless of the specific market, balanced by market concentration, is referred to as supply-demand fundamentals or economic fundamentals. While the market structure does not guarantee competitive outcomes, overall the market structure of the PJM aggregate Energy Market remains reasonably competitive for most hours.

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. 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.

On September 24, 2008, PJM retroactively changed prices for eight hours for September 4, 2008. Changing market prices after the fact should be avoided, even when the reason is a failure to mitigate local market power, as it was here. Markets depend on prices and market participants depend on the finality and certainty of prices. Ideally, observed prices in real time would be final, but this has not yet been possible in the PJM markets. Nonetheless, PJM makes it a practice to finalize prices for the Real-Time Energy Market by noon the following day. This approach to final and certain prices is also consistent with the view that market power mitigation should be done ex ante, whenever possible, to ensure that market price signals are accurate in real time.

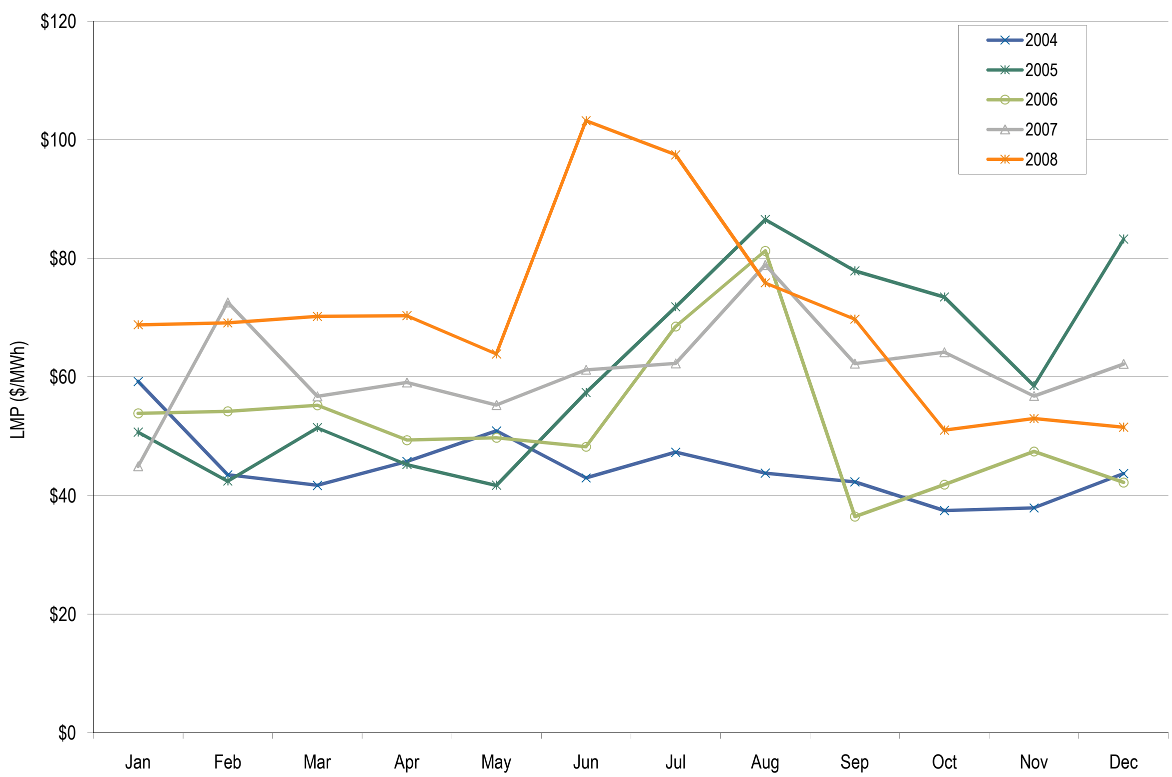
The three pivotal supplier test is applied by PJM on an ongoing basis for local energy markets in order to determine whether offer capping is required for transmission constraints. This is a flexible, targeted real-time measure of market structure which replaced the offer capping of all units required 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.

Energy Market results for 2008 generally reflected supply-demand fundamentals. Higher prices in the Energy Market were the result of higher fuel costs. The load-weighted, average LMP for 2008 was 15.4 percent higher than the load-weighted, average LMP for 2007. The fuel-cost-adjusted, load-weighted, average LMP in 2008 was 16.0 percent lower than the load-weighted LMP in 2007. If fuel costs for the year 2008 had been the same as for 2007, the 2008 load-weighted LMP would have been lower, $51.79 per MWh, instead of the observed $71.13 per MWh. Higher coal, gas and oil prices in 2008 resulted in higher prices in 2008 than would have occurred if fuel prices had remained at 2007 levels.

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 remain potential sources of concern in the Energy Market. The MMU concludes that the PJM Energy Market results were competitive in 2008.

Figure 3 PJM real-time, monthly, load-weighted, average LMP: Calendar years 2004 to 2008



Energy Market, Part 2

The MMU analyzed measures of PJM Energy Market structure, participant conduct and market performance for 2008. As part of the review of market performance, the MMU analyzed the net revenue performance of PJM markets, the characteristics of existing and new capacity in PJM, the definition and existence of scarcity conditions in PJM and the performance of the PJM operating reserve construct.

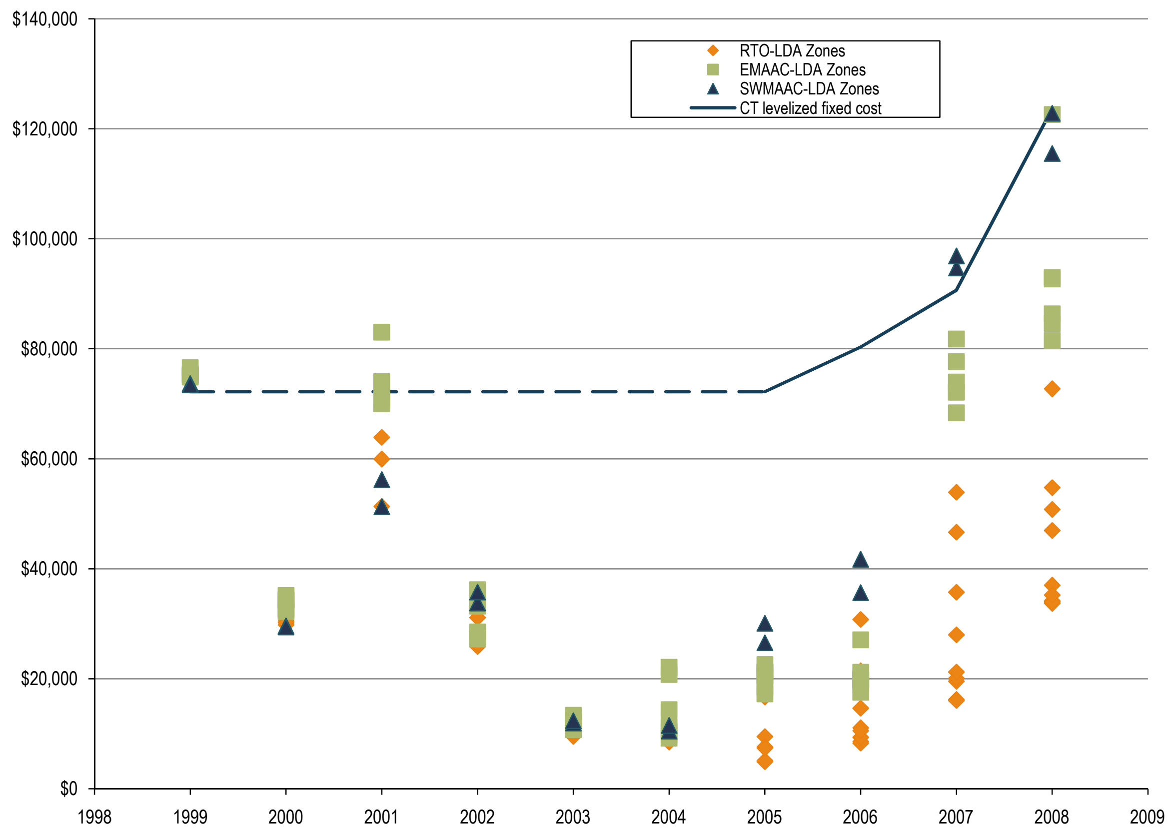
Net Revenue

- **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, 2008 net revenue showed mixed results compared to 2007. For the new entrant combustion turbine (CT), all zones showed an increase in net revenue compared to 2007, which in many cases reflects lower energy revenue offset by increased capacity revenue. For the new entrant combined cycle (CC), all zones showed an increase in net revenue compared to 2007, which reflects an increase in energy and capacity market revenue in most eastern zones and an increase in just capacity market revenue in most western zones. For the new entrant coal plant (CP), most zones showed an increase in net revenue compared to 2007, which in many cases reflects lower energy market revenue offset by increased capacity market revenue. The levels of net revenue in 2008 for these new peaking, midmerit and coal-fired baseload power plants vary significantly by location. Higher energy market prices were offset by higher generation costs, and as a result, there were several zones for each technology that showed a decrease in energy market net revenue, despite higher price levels. However, revenues associated with the sale of capacity resources increased for all zones in 2008 as the RPM construct was in effect for a full calendar year. The fixed costs of constructing a combined-cycle generation resource were fully covered in some, but not all, PJM control zones. The fixed costs of constructing a combustion turbine were 99 percent covered by net revenues in AECO and Pepco Control Zones and 93 percent covered in the BGE Control Zone. There were no zones with revenue adequacy for the CP technology despite the full year of RPM capacity payments, as a result of increased fuel costs. The results from 2008 highlight the significance of the RPM construct's contribution to capital cost recovery and to the incentive to invest in new PJM generation resources in years when energy market and ancillary service revenues are inadequate to cover the costs of this investment.

  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 2008 net revenue using PJM real-time average locational marginal prices (LMPs) was $50,532 per MW-year for a CT, the zonal maximum net revenue was $122,845 in the Pepco Control Zone and the minimum was $33,727 in the AEP Control Zone. While the PJM average net revenue in 2008 was $103,928 per MW-year for a CC, the zonal maximum net revenue was $219,105 in the Pepco Control Zone and the minimum was $61,141 in the DLCO Control Zone. While the PJM average net revenue in 2008 was $218,144 per MW-year for a CP, the zonal maximum net revenue was $397,620 in the Pepco Control Zone and the minimum was $160,462 in the DAY Control Zone.

Figure 4 New entrant CT real-time net revenue and 20-year levelized fixed cost as of 2008 by LDA (Dollars per installed MW-year): Calendar years 1999 to 2008



Existing and Planned Generation

- **PJM Installed Capacity.** During the period January 1, through December 31, 2008, PJM installed capacity resources rose slightly from 164,277 MW on January 1 to 164,895 MW on December 31.

- **PJM Installed Capacity by Fuel Type.** Of the total installed capacity at the end of 2008, 40.7 percent was coal; 29.3 percent was natural gas; 18.5 percent was nuclear; 6.5 percent was oil; 4.5 percent was hydroelectric; 0.4 percent was solid waste, and 0.1 percent was wind.

- **Generation Fuel Mix.** During 2008, coal provided 55.0 percent, nuclear 34.6 percent, gas 7.3 percent, oil 0.3 percent, hydroelectric 1.7 percent, solid waste 0.7 percent and wind 0.5 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 Pricing Events in 2008.** PJM did not declare a scarcity event in 2008.

- **Scarcity.** A wholesale energy market will not consistently result in adequate revenues in the absence of a carefully designed and comprehensive approach to scarcity pricing. This is a result, not of offer capping, but of the fundamentals of wholesale power markets which must carry excess capacity in order to meet externally imposed reliability rules.

  Scarcity revenues to generation owners can come entirely from energy markets or they can come from a combination of energy and capacity markets. The RPM capacity market design reflects the recognition that the energy markets, by themselves and in the absence of a carefully designed expansion of scarcity pricing, will not result in adequate revenues. The RPM design provides an alternate method for collecting scarcity revenues.

  The revenues in the capacity market are scarcity revenues. If the revenues collected in the RPM market are adequate, it is not essential that a scarcity pricing mechanism exist in the energy market. Nonetheless, it would be preferable to have a scarcity pricing mechanism in the energy market because it provides direct, market-based incentives to load and generation, as long as the market rules are designed to ensure that scarcity revenues directly offset RPM revenues to prevent double collection of scarcity revenues.

  A hybrid market design can provide scarcity revenues both via scarcity pricing in the energy market and via the capacity market. However, if scarcity revenues are provided in the energy market, there must be an explicit mechanism to remove those revenues from capacity market revenues. This offset must reflect the actual scarcity revenues and not those reflected in forward curves or forecast by analysts from any organization. The absence of such a mechanism is likely to result in an over collection of scarcity revenues as such revenues are episodic and unlikely to be fully reflected in forward curves, even if such curves were based on a liquid market three years forward and reflected locational results, which they do not. The most straightforward way to ensure that such over collection does not occur would be to ensure that capacity resources do not receive scarcity revenues in the energy market in the first place. The settlements process can remove any scarcity revenues from payments to capacity resources and eliminate the need for a complex, uncertain, after the fact procedure for offsetting scarcity revenues in the capacity market.

- **Modifications to Scarcity Pricing.** While PJM's triggers for administrative scarcity pricing are reasonable measures of scarcity conditions, PJM's 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 current single scarcity price signal should be replaced by locational signals. Locational scarcity signals could be implemented via reserve requirements modeled as constraints for scarcity regions, with administrative scarcity penalty factors, in the security constrained dispatch. The level of the penalty factor and the reserve target would be determined by the severity level of the scarcity event. This would provide a means to signal scarcity that is consistent with economic dispatch, consistent with locational pricing and consistent with competitive market outcomes.

Administrative scarcity pricing should include stages, based on system conditions, with progressive impacts on prices. The trigger for each stage should be based on the level of available operating reserve using a dynamically determined and relevant operating reserve requirement and the progressive use of emergency measures. Implemented as scarcity region specific operating reserve constraints in the security constrained dispatch, the severity of scarcity event should be reflected in a set of increasing, administrative penalty factors.

If implemented using reserve requirement constraints with escalating penalty factors, the scarcity pricing mechanism would eliminate the need to lift offer capping during a scarcity pricing event. Properly set, the penalty factors would increase prices on the system to provide a locational pricing signal reflecting the severity of the shortage. This approach also eliminates the incentive for participants to make non-competitive energy offers in anticipation of scarcity events. Keeping offers consistent during the event would have the added benefit of avoiding the operational issues involved with sudden changes in the economic dispatch order before, during and after a scarcity event.

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 2008.** The level of operating reserve credits and corresponding charges decreased in 2008 by 6.5 percent compared to 2007. This was the result of a large decrease in the amount of synchronous condensing operating reserve credits, a smaller decrease in the amount of balancing operating reserve credits and an increase in the amount of day-ahead operating reserve credits.

- **New Operating Reserve Rules in 2008.** New rules governing the payment of operating reserves credits and the allocation of operating reserves charges became effective on December 1, 2008. The new operating reserve rules represent positive steps towards the goals of removing the ability to exercise market power and refining the allocation of operating reserves charges to better reflect causal factors.

Table 2 Total day-ahead and balancing operating reserve credits: Calendar years 1999 to 2008

	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	62.1%	9.6%	0.3412	NA	0.5346	NA
2001	$290,867,269	34.0%	8.7%	0.2746	(19.5%)	1.0700	100.2%
2002	$237,102,574	(18.5%)	5.0%	0.1635	(40.4%)	0.7873	(26.4%)
2003	$289,510,257	22.1%	4.2%	0.2261	38.2%	1.1971	52.0%
2004	$414,891,790	43.3%	4.8%	0.2300	1.7%	1.2362	3.3%
2005	$682,781,889	64.6%	3.0%	0.0762	(66.9%)	2.7580	123.1%
2006	$322,315,152	(52.8%)	1.5%	0.0781	2.6%	1.3315	(51.7%)
2007	$459,124,502	42.4%	1.5%	0.0570	(27.0%)	2.3310	75.1%
2008	$429,253,836	(6.5%)	1.3%	0.0844	48.0%	2.1132	(9.3%)

Energy Market, Part 2 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 a direct and explicit offset for 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 prior to the RPM construct was generally 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 have been some units in PJM, needed for reliability, with revenues less than annual going-forward costs, which, if it persists, is a signal 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. In 2007, 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.

In 2008, market results were mixed. The cost of fuel inputs eroded the increased revenue from higher price levels, but that effect was less significant in some constrained eastern control zones. The result is that while the Energy Market Net Revenues alone are insufficient to recover capital costs in any control zone, when combined with RPM Capacity revenue, total net revenue in several eastern zones is sufficient to cover the investment costs of a new entrant combined cycle plant and total net revenue in three eastern zones are approximately sufficient to cover the investment costs of a new entrant combustion turbine.

The net revenue results illustrate some fundamentals of the PJM wholesale power market. CTs are generally the highest incremental cost units and therefore tend to be marginal in the energy market and set prices, when they run. When this occurs, CT energy market net revenues are small and there is little contribution to fixed costs. High demand hours result in less efficient CTs setting prices, which results in higher net revenues for more efficient CTs. There were relatively few high demand days in 2008. Scarcity revenues in the energy market contribute to covering fixed costs, when they occur, but scarcity revenues are not a predictable and systematic source of net revenue. In the PJM design, the balance of the net revenue required to cover the fixed costs of peaking units comes from the Capacity Market. However, when the actual fixed costs of capacity increase rapidly, there is a corresponding lag in Capacity Market prices which will tend to lead to an under recovery of the fixed costs of CTs. That is what occurred in 2008. The fixed costs of a CT in 2008 are substantially higher than the fixed costs of a CT in 2007, but the clearing prices in the Capacity Market reflect the prior, lower costs of a CT that were incorporated in the demand curve for the auctions that determined prices in the 2007/2008 and 2008/2009 RPM auctions.

The net revenue performance of combined cycle units (CCs) was significantly better than that of CTs. CCs, like CTs, burn gas but are more efficient than CTs and therefore as clearing prices set by CTs increase, net revenues from the Energy Market increase for CCs. These inframarginal energy revenues were the source of the higher CC net revenues in 2008.

Coal units (CP) are marginal in the PJM system for a substantial number of hours. When this occurs, CP energy market net revenues are small and there is little contribution to fixed costs. When less efficient coal units are on the margin net revenues are higher for more efficient coal units. Coal units also receive higher net revenues as a result of CTs setting prices based on higher gas costs, when they run.

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 and 2008, especially the Capacity Markets, represented a significant improvement over prior performance. The reaction of investors will determine whether the market design modifications are successful.

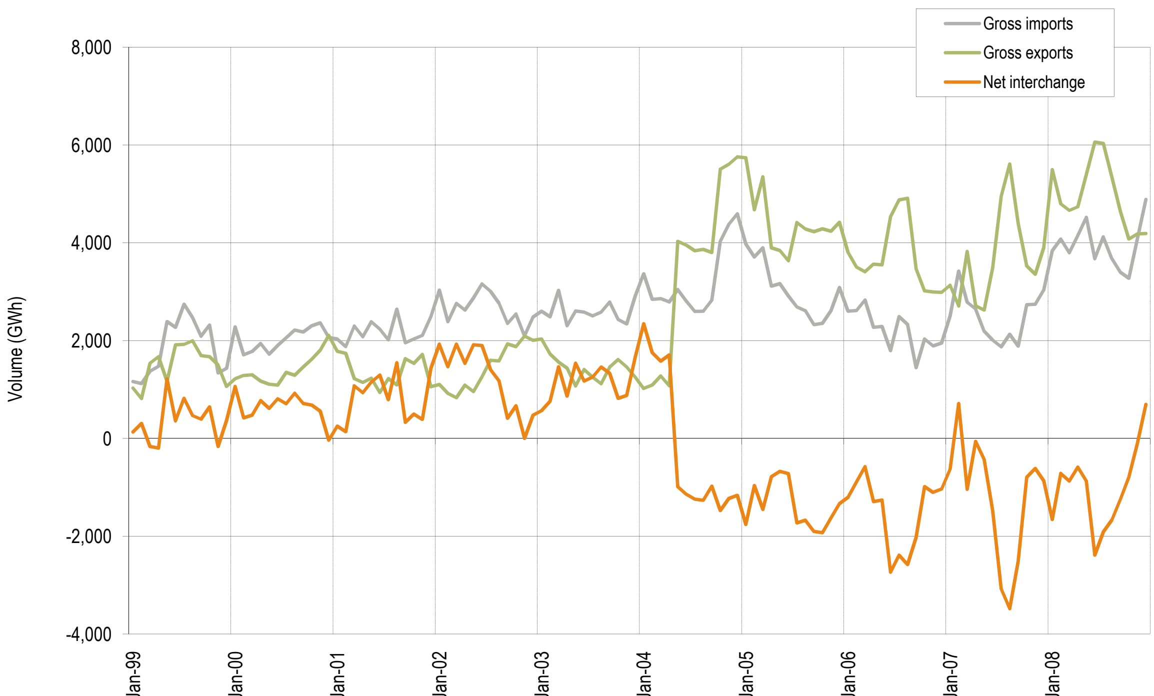
Interchange Transactions

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 balancing authorities.

Interchange Transaction Activity

- **Aggregate Imports and Exports in the Real-Time Energy Market.** During 2008, PJM was a net exporter of energy in the Real-Time Market for all months except December. In the Real-Time Market, monthly net interchange averaged -1,010 GWh.[10] Gross monthly import volumes averaged 3,962 GWh while gross monthly exports averaged 4,972 GWh.

Figure 5 PJM scheduled import and export transaction volume history: Calendar years 1999 to 2008



- **Aggregate Imports and Exports in the Day-Ahead Energy Market.** In 2008, gross imports in the Day-Ahead Energy Market were 90 percent of the Real-Time Market's gross imports (85 percent in 2007) while gross exports in the Day-Ahead Market were 106 percent of the Real-Time Market's gross exports (103 percent in 2007) and net interchange in the Day-Ahead Energy Market exceeded net interchange in the Real-Time Energy Market by 58 percent. In

10 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.

the Day-Ahead Market, monthly net interchange averaged -1,732 GWh. Gross monthly import volumes averaged 3,552 GWh while gross monthly exports averaged 5,284 GWh.

- **Interface Imports and Exports in the Real-Time Market.** In the Real-Time Market in 2008, there were net exports at 16 of PJM's 20 interfaces. The top three net exporting interfaces in the Real-Time Market accounted for 53 percent of the total net exports: PJM/New York Independent System Operator, Inc. (NYIS) with 24 percent, PJM/Neptune (NEPT) with 18 percent, and PJM/Tennessee Valley Authority (TVA) with 11 percent of the net export volume. Four PJM interfaces had net imports, with two importing interfaces accounting for 77 percent of net import volume: PJM/Ohio Valley Electric Corporation (OVEC) with 59 percent and PJM/Michigan Electric Coordinated System (MECS) with 18 percent.

- **Interface Imports and Exports in the Day-Ahead Market.** In the Day-Ahead Market, there were net exports at 16 of PJM's 20 interfaces. The top three net exporting interfaces accounted for 59 percent of the total net exports, PJM/western Alliant Energy Corporation (ALTW) with 26 percent, PJM/Northern Indiana Public Service Company (PJM/NIPS) with 18 percent and PJM/NEPTUNE (NEPT) with 15 percent. There were net imports in the Day-Ahead Market at four of PJM's 20 interfaces. The top two importing interfaces accounted for 92 percent of the total net imports, PJM/OVEC with 75 percent and PJM/Ameren – Illinois (AMIL) with 17 percent.

Interactions with Bordering Areas

- **PJM Interface Pricing with Organized Markets.**

  — **PJM and Midwest ISO Interface Pricing.** During 2008, 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 2008, 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 increased by 87.5 percent, from 80 in 2007 to 150 in 2008. The increase in TLRs declared by PJM can be attributed to transmission line outages caused by storms and tornados. These outages limited the ability to utilize market signals to manage constraints.

- **Operating Agreements with Bordering Areas.**

  — **PJM and New York Independent System Operator, Inc.** Joint Operating Agreement (JOA).[11] On May 22, 2007, the JOA between PJM and the New York Independent System

11 See PJM. "Joint Operating Agreement Among And Between New York Independent System Operator Inc. And PJM Interconnection, L.L.C." (May 22, 2007) (Accessed January 16, 2009) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/20071102-nyiso-pjm.ashx> (208 KB).

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. While the JOA does not include provisions for market-based congestion management or other market-to-market activity, at the request of PJM, PJM and the NYISO began discussion of a market-based congestion management protocol.

— **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., executed on December 31, 2003, continued in 2008. The market-based congestion management process is reviewed and modified as necessary through the Congestion Management Process (CMP) protocols.[12]

— **PJM, Midwest ISO and TVA Joint Reliability Coordination Agreement.**[13] 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 2008.

— **PJM and Progress Energy Carolinas, Inc.** Joint Operating Agreement.[14] 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 2008.

— **PJM and Virginia and Carolinas Area (VACAR) South Reliability Coordination Agreement.**[15] 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 confidential locational interface pricing agreements with Duke Energy Carolinas, Progress Energy Carolinas and North Carolina Municipal Power Agency (NCMPA) in 2007 that provided more advantageous pricing to these companies than the applicable interface pricing rules. Each of these agreements established a locational price for purchases and sales between PJM and the individual company that applies under specified conditions. There are a number of issues with these agreements including that they were not made public until specifically requested by the MMU, that the pricing was not available to other participants in similar circumstances, that the pricing was not designed to reflect actual power flows, that the pricing did not reflect full security constrained economic dispatch in the external areas and that the pricing did not reflect appropriate price signals. PJM recognized that the price signals in the agreements

12 See PJM. "Joint Operating Agreement between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C." (November 1, 2007) (Accessed January 16, 2009) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/joa-complete.ashx> (1,534 KB).

13 See PJM. "Congestion Management Process (CMP) Master" (May 1, 2007) (Accessed January 16, 2009) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/20080502-miso-pjm-tva-baseline-cmp.ashx> (432 KB).

14 See PJM. "Joint Operating Agreement (JOA) between Progress Energy Carolinas, Inc. and PJM" (July 29, 2005) (Accessed January 16, 2009) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/20081114-progress-pjm-joa.ashx> (2.98 MB).

15 See PJM. "Adjacent Reliability Coordinator Coordination Agreement" (May 23, 2007) (Accessed January 16, 2009) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/executed-pjm-vacar-rc-agreement.ashx> (528 KB).

were inappropriate and notified the counterparties that PJM would terminate the agreements effective January 31, 2009.

- **Consolidated Edison Company of New York, Inc.** (Con Edison) and Public Service Electric and Gas Company (PSE&G) Wheeling Contracts. During 2008, PJM continued to operate under the terms of the operating protocol developed in 2005.[16] Significant progress was also made on the 19 items identified in the work plan to improve protocol performance in 2008.

- **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 2008 power flows were only from PJM to New York. The average hourly flow for 2008 was -572 MW.

Interchange Transaction Issues

- **Spot Import.** Prior to April 1, 2007, PJM did not limit non-firm service imports that were willing to pay congestion, including spot imports, secondary network service imports and bilateral imports using non-firm point-to-point service. However, PJM interpreted its Joint Operating Agreement (JOA) with Midwest ISO to require a limitation on cross-border transmission service and energy schedules in order to limit the impact of such transactions on selected external flowgates.[17] The rule caused the availability of spot import service to be limited by ATC on the transmission path. As a result of the rule, requests for service sometimes exceeded the amount of service available to customers. Unlike non-firm point-to-point WPC service, spot import (a network service) is provided at no charge to the market participant offering into the PJM spot market.

  The new spot import rules have incented participant actions to evade the limits and to hoard spot import capability. The MMU recommends that PJM reconsider whether the new approach to limiting spot import service is required or whether a return to the prior policy with an explicit system of managing any related congestion is preferable.

- **Up-To Congestion.** In 2008, market participants requested that PJM increase the maximum value for up-to congestion offers, and to also allow negative offers for these transactions. PJM expressed concerns regarding the mismatch between up-to congestion transactions in the Day-Ahead Market and real-time transactions.[18] 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. Increasing the offer cap, and allowing negative offers, could potentially increase the cleared volume of up-to congestion transactions, and aggravate the issue.

16 111 FERC ¶ 61,228 (2005).

17 See "WPC White Paper" (April 20, 2007) (Accessed December 29, 2008) <http://www.pjm.com/~/media/etools/oasis/wpc-white-paper.ashx> (97 KB).

18 See PJM. "Up-to Congestion Transactions. Proposed Interim Changes Pending Development of a Spread Product" (February 21, 2008) (Accessed February 18, 2009) <http://www.pjm.com/~/media/committees-groups/committees/mrc/20080221-item-03-up-to-congestion-transactions.ashx> (38KB).

On February 21, 2008, the Markets and Reliability Committee (MRC) approved PJM's proposed resolution to the request for implementation on March 1, 2008.[19] The proposal allowed for an increased offer cap from $25 to ± $50, and explicitly allowed for negative offers. PJM also eliminated certain available sources and sinks in an effort to address the mismatches between the Day-Ahead and Real-Time Markets.

The MMU recommends that PJM consider eliminating all internal PJM buses for use in up-to congestion bidding. In effect, the use of specific buses is equivalent to creating a scheduled transaction which will not equal the actual corresponding power flow.

- **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 1.7 percent in 2008, greater differences existed at individual interfaces.[20] Loop flows are a significant concern because they have negative impacts on the efficiency of market areas with explicit locational pricing, including impacts on locational prices, on Financial Transmission Right (FTR) revenue adequacy and on system operations, and can be evidence of attempts to game such markets.

  — **Loop Flows at the PJM/MECS and PJM/TVA Interfaces.** As it had in 2007, the PJM/Michigan Electric Coordinated System (MECS) Interface continued to exhibit large imbalances between scheduled and actual power flows (-14,014 GWh in 2008 and -10,813 GWh in 2007), particularly during the overnight hours. The PJM/TVA Interface also exhibited large mismatches between scheduled and actual power flows (4,065 GWh in 2008 and 5,906 GWh in 2007), 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 improvement 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 in late 2006 and during 2007 was sustained in 2008 although the loop flows across the southern interfaces increased in 2008 from 2007. These improvements followed the changes from the Southeast and Southwest interface pricing points to the SOUTHIMP and SOUTHEXP interface pricing points that occurred on October 1, 2006.

  — **Loop Flows at PJM's Northern Interfaces.** In 2008, new loop flows were created when pricing rules gave participants an incentive to schedule power flows in a manner inconsistent with the associated actual power flows. In 2008, market participants scheduled transactions on a path from the NYISO to PJM through Ontario's Independent Electricity System Operator (IESO) and Midwest ISO systems, rather than reflecting the actual power flows which were

19 See PJM. "20080221-minutes.pdf" (February 21, 2008) (Accessed January 15, 2009) <http://www.pjm.com/Media/committees-groups/committees/mrc/20080221-minutes.pdf > (61KB).

20 The *2007 State of the Market Report* reported the difference between scheduled and actual flows as 0.5 percent. The calculation method incorrectly accounted for some dynamic schedules. The recalculated 2007 difference is 1.6 percent.

primarily directly from NYISO to PJM. The participants faced a price incentive to engage in this behavior. When export transactions were scheduled from NYISO to Ontario, participants paid the lower export price at NYISO's Ontario interface rather than the higher export price at NYISO's PJM interface. The export price differences were more than enough to cover the cost of transmission through Ontario and Midwest ISO into PJM. When the export transactions were approved in the NYISO hourly market, the NYISO committed additional generation to support the transactions. The actual flow of energy that resulted was primarily directly from NYISO to PJM across the PJM/NYISO Interface. PJM's interface pricing calculations correctly reflected the actual power flows, but NYISO's interface pricing did not. One result was increased congestion charges in the NYISO system. PJM's interface pricing rules eliminated the incentive to schedule power flows on paths inconsistent with actual power flows in order to take advantage of price differences. In this case, PJM interface pricing rules resulted in PJM paying for the import based on its source in the NYISO and disregarded the scheduled path.

— **Data Required for Full Loop Flow Analysis.** A complete analysis of loop flow across the Eastern Interconnection could enhance overall market efficiency and shed light on the interactions among market and non market areas. This is important because loop flows have negative impacts on the efficiency of market prices in markets with explicit locational pricing and can be evidence of attempts to game such markets. Loop flows also have poorly understood impacts on non market areas. More broadly, a complete analysis of loop flow could advance the overall transparency of electricity transactions. The term non market area is a misnomer in the sense that all electricity transactions are part of the broad energy market in the Eastern Interconnection. There are areas with transparent markets, and there are areas with less transparent markets, but these areas together comprise a market, and overall market efficiency would benefit from the increased transparency that would derive from a better understanding of loop flow.

The MMU recommends that PJM and the Midwest ISO reiterate their initial recommendation to create an energy schedule tag archive, as this would provide the transparency necessary for a complete loop flow analysis. The data required for a meaningful loop flow analysis include tag data, market flow impact data, actual flowgate flows data and balancing authority ACE data for the Eastern Interconnection. The MMU recommends that the RTOs request action, and that both NERC and FERC consider taking the action required to make these data available to the RTOs and market monitors to make a full market analysis possible.

Interchange Transactions Conclusion

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

The MMU analyzed the transactions between PJM and neighboring balancing authorities for 2008, 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 53 percent of the total real-time net exports and two interfaces accounted for 77 percent of the real-time net import volume. Three interfaces accounted for 59 percent of the total day-ahead net exports and two interfaces accounted for 92 percent of the day-ahead net import volume.

As the data show, there is a substantial level of transactions between PJM and the contiguous balancing authorities. 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. 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 balancing authorities. 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. However, more needs to be done to assure that market signals 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 their appropriate share of the costs of redispatch.

In order to manage interactions with non market areas, PJM has entered into coordination agreements with other balancing authorities 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 balancing authorities 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 balancing authorities 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 balancing authorities. 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. The MMU recommends that the RTOs request action, and that both NERC and FERC consider taking the action required to make these data available to the RTOs and market monitors to make a full market analysis possible.

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 to or export power from 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

Each organization serving PJM load must meet its capacity obligations by acquiring capacity resources through the PJM Capacity Market where load serving entities (LSEs) must pay the locational capacity price for their zone. LSEs can affect the financial consequences of purchasing capacity in the capacity market by constructing generation and offering it into the capacity market, by developing demand-side resources and offering them into the capacity market, or constructing transmission upgrades and offering them into the capacity market

The MMU analyzed market structure, participant conduct and market performance in the PJM Capacity Market for calendar year 2008, including supply, demand, concentration ratios, pivotal suppliers, volumes, prices, outage rates and reliability.

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. The RPM design 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.

Under RPM, capacity obligations are annual. Base Residual Auctions (BRA) are held for delivery years that are three years in the future. First, Second and Third Incremental RPM Auctions may be held for each delivery year, occurring 23, 13 and four months, respectively, prior to the delivery year. RPM prices are locational and may vary depending on transmission constraints.[21] Existing generation capable of qualifying as a capacity resource must be offered into RPM Auctions, except for the fixed resource requirement (FRR) option. Under RPM, participation by LSEs is mandatory, except for the FRR option. 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 in each BRA. Under RPM there are performance incentives for generation. Under RPM there are explicit market power mitigation rules that define the must offer requirement, 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 RPM, demand-side resources may be offered directly into RPM auctions and receive the clearing price.

Market Structure

- **Supply.** Total internal capacity increased 1,762.0 MW from 155,206.0 MW on June 1, 2007, to 156,968.0 MW on June 1, 2008.[22] This increase was the result of 89.4 MW of new generation, 112.6 MW from resources which came out of retirement, and 146.2 MW from generation

21 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.

22 Unless otherwise specified, all volumes are in terms of UCAP.

uprates. DR offers increased 595.3 MW. Improvements in the net equivalent demand forced outage rate (EFORd) effect added 818.5 MW.

In the 2009/2010, 2010/2011 and 2011/2012 auctions, new generation increased 3,049.8 MW; 651.9 MW came out of retirement and net generation deratings were 1,407.7 MW, for a total of 2,294.0 MW. DR offers increased 948.7 MW through June 1, 2011 offset in part by 328.0 MW from higher EFORds. The net effect from June 1, 2008, through June 1, 2011, was an increase in total internal capacity of 2,914.7 MW (1.9 percent) from 156,968.0 MW to 159,882.7 MW.

In the 2008/2009 auction, 15 more generating resources made offers than in the 2007/2008 RPM Auction. The increase included five new wind resources (66.1 MW), three new diesel resources (23.3 MW) and two resources (112.6 MW) which came out of retirement while the remaining five resources were the result of a reclassification of external resources.

In the 2009/2010 auction, 17 more generating resources made offers than in the 2008/2009 RPM Auction. The increase included eight new combustion turbine (CT) resources (380.2 MW), two new diesel resources (9.2 MW) and one new steam resource (49.8 MW) while the remaining six resources included more resources imported, fewer resources exported, a decrease in resources excused from offering into the auction and fewer resources removed from the auction under the fixed resource requirement (FRR) option.

In the 2010/2011 auction, 11 more generating resources made offers than in the 2009/2010 RPM auction. The net increase of 11 resources consisted of 15 new resources, four reactivated resources and three resources from the FRR participant, offset by three retired resources, four deactivated resources, three resources exported from PJM and one resource excused from offering. There were seven new CT resources (270.5 MW), three new diesel resources (16.4 MW), five new wind resources (120.0 MW) and four reactivated resources (165.0 MW) for a total of 19 resources. There were three resources that retired (358.3 MW), four resources that were deactivated (52.9 MW) and an additional three resources exported out of PJM (521.5 MW) for a total of 10 resources.

In the 2011/2012 auction, 21 more generating resources made offers than in the 2010/2011 RPM auction. The net increase of 21 resources consisted of 20 new resources (2,203.7 MW), four reactivated resources (486.9 MW), three fewer excused resources (126.3 MW), and one additional resource imported (663.2 MW), offset by five additional FRR resources (64.2 MW) and two retired resources (85.8 MW). The new resources consisted of 11 new CT resources (728.7 MW), four new wind resources (75.2 MW), two new steam resources (838.0 MW), one new combined cycle resource (556.5 MW), one new diesel resource (4.2 MW) and one new solar resource (1.1 MW).

Table 3 PJM capacity summary (MW): June1, 2007, through June 1, 2011

	01-Jun-07	01-Jun-08	01-Jun-09	01-Jun-10	01-Jun-11
Installed capacity (ICAP)	163,721.1	164,444.1	166,916.0	168,061.5	172,666.6
Unforced capacity	154,076.7	155,590.2	157,628.7	158,634.2	163,144.3
Cleared capacity	129,409.2	129,597.6	132,231.8	132,190.4	132,221.5
RPM reliability requirement (pre-FRR)	148,277.3	150,934.6	153,480.1	156,636.8	154,251.1
RPM reliability requirement (less FRR)	125,805.0	128,194.6	130,447.8	132,698.8	130,658.7
RPM net excess	5,240.5	5,011.1	3,403.3	1,149.2	3,156.6
Imports	2,809.2	2,460.3	2,505.4	2,750.7	6,420.0
Exports	(3,938.5)	(3,838.1)	(2,194.9)	(3,147.4)	(3,158.4)
Net exchange	(1,129.3)	(1,377.8)	310.5	(396.7)	3,261.6
DR cleared	127.6	536.2	892.9	939.0	1,364.9
ILR	1,636.3	3,608.1	2,107.5	2,110.5	1,593.8
FRR DR	445.6	452.8	488.2	452.9	452.9

- **Demand.** There was a 2,657.3 MW increase in the RPM reliability requirement from 148,277.3 MW on June 1, 2007 to 150,934.6 MW on June 1, 2008. On June 1, 2008, PJM EDCs and their affiliates maintained an 80.1 percent market share of load obligations under RPM, up from 77.5 percent on June 1, 2007.

- **Market Concentration.** For the 2008/2009, 2009/2010, 2010/2011, and 2011/2012 RPM Auctions, all defined markets failed the preliminary market structure screen (PMSS). In each BRA 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 auctions. In the 2008/2009 Third Incremental Auction, 22 of 40 participants in the RTO/EMAAC RPM market and all three participants in the SWMAAC RPM market failed the market structure test. Offer caps were applied to those sellers that failed the test.

- **Imports and Exports.** Net exchange decreased 248.5 MW from June 1, 2007 to June 1, 2008. Net exchange, which is imports less exports, decreased due to a decrease in exports of 100.4 MW and a larger decrease in imports of 348.9 MW.

- **Demand-Side Resources.** Under RPM, demand-side resources in the Capacity Market, a combination of DR cleared in the RPM Auctions and certified/forecast interruptible load for reliability (ILR), increased by 2,403.6 MW from 1,763.9 MW on June 1, 2007 to 4,167.5 MW on June 1, 2008.

- **Net Excess.** Net excess decreased 229.42 MW from 5,240.5 MW on June 1, 2007 to 5,011.1 MW on June 1, 2008.

Market Conduct

- **2008/2009 RPM Base Residual Auction.** Of the 1,076 generating resources which submitted offers, unit-specific offer caps were calculated for 117 resources (10.9 percent). Offer caps of all kinds were calculated for 567 resources (52.7 percent), of which 399 were based on the technology specific default (proxy) ACR posted by the MMU.

- **2008/2009 RPM Third Incremental Auction.** Of the 327 generating resources which submitted offers, unit-specific offer caps were calculated for 24 resources (7.3 percent). Offer caps of all kinds calculated for 170 resources (51.9 percent), of which 123 were based on the technology specific default (proxy) ACR posted by the MMU.

- **2009/2010 RPM Base Residual Auction.** Of the 1,093 generating resources which submitted offers, unit-specific offer caps were calculated for 151 resources (13.8 percent). Offer caps of all kinds were calculated for 550 resources (50.3 percent), of which 377 were based on the technology specific default (proxy) ACR posted by the MMU.

- **2010/2011 RPM Base Residual Auction.** Of the 1,104 generating resources which submitted offers, unit-specific offer caps were calculated for 154 resources (13.9 percent). Offer caps of all kinds were calculated for 532 resources (48.1 percent), of which 370 were based on the technology specific default (proxy) ACR posted by the MMU.

- **2011/2012 RPM Base Residual Auction.** Of the 1,125 generating resources which submitted offers, unit-specific offer caps were calculated for 145 resources (12.9 percent). Offer caps of all kinds were calculated for 472 resources (42.0 percent), of which 301 were based on the technology specific default (proxy) ACR posted by the MMU.

Market Performance

2008/2009 RPM Base Residual Auction

- **RTO.** Total internal RTO unforced capacity of 156,968.0 MW includes all generating units and DR that qualified as a PJM capacity resource for the 2008/2009 RPM base residual auction, excludes external units and reflects owners' modifications to installed capacity (ICAP) ratings. Including FRR, committed resources and imports, RPM capacity was 136.237.3 MW. The 129,597.6 MW of cleared resources for the entire RTO represented a reserve margin of 17.5 percent, which was 1,403.0 MW greater than the reliability requirement of 128,194.6 MW (installed reserve margin (IRM) of 15.0 percent) and resulted in a clearing price of $111.92 per MW-day.

  Total cleared resources in the RTO were 129,597.6 MW which resulted in a net excess of 5,011.1 MW, a decrease of 229.4 MW from the net excess of 5,240.5 MW in the 2007/2008 RPM base residual auction. Certified interruptible load for reliability (ILR) was 3,608.1 MW.

Cleared resources across the entire RTO will receive a total of $6.1 billion based on the unforced MW cleared and the prices in the 2008/2009 RPM BRA, an increase of approximately $1.8 billion from the 2007/2008 planning year.

- **EMAAC.**[23] Total internal EMAAC unforced capacity of 31,379.1 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 31,396.7 MW. Of the 1,549.5 MW of incremental supply, 401.4 MW cleared, which resulted in a resource-clearing price of $148.80 per MW-day.

  Total resources in EMAAC were 38,161.3 MW, which when combined with certified ILR of 622.6 MW resulted in a net excess of 893.2 MW (2.3 percent) greater than the reliability requirement of 37,890.7 MW.

- **SWMAAC.** Total internal SWMAAC unforced capacity of 10,777.1 MW includes all generating units and DR that qualified as a PJM capacity resource, excludes external units and reflects owners' modifications to ICAP ratings. There were no imports from outside PJM into SWMAAC. Of the 290.5 MW of incremental supply, 285.6 cleared, which resulted in a resource-clearing price of $210.11 per MW-day.

  Total resources in SWMAAC were 16,231.2 MW, which when combined with certified ILR of 219.7 MW resulted in a net deficit of 111.0 MW (0.7 percent) less than the reliability requirement of 16,561.9 MW.

2008/2009 RPM Third Incremental Auction

- **RTO.** There were 2,339.4 MW offered into the Third Incremental Auction while buy bids totaled 2,251.8 MW. Cleared volumes in the RTO were 1,011.6 MW, resulting in an RTO clearing price of $10.00 per MW-day. The price was set by the transition adder. The 1,307.2 MW of uncleared volumes can be used as replacement capacity or traded bilaterally.

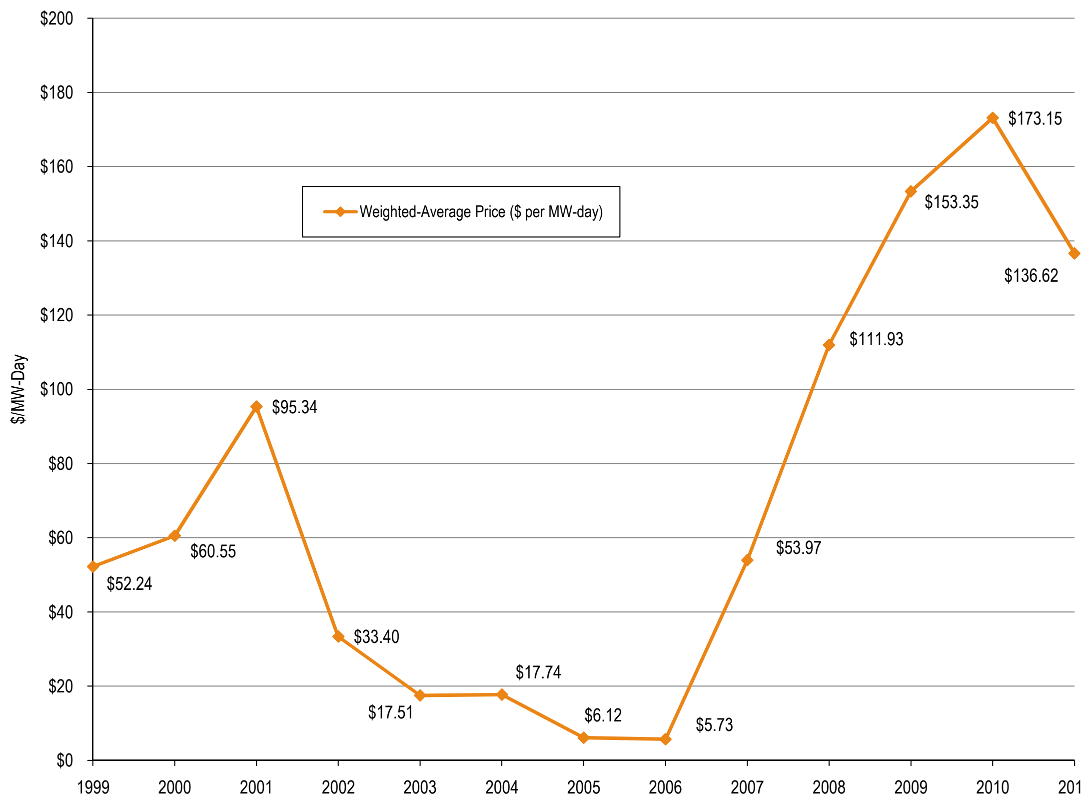
  Cleared resources across the entire RTO will receive a total of $5.4 million based on the unforced MW cleared and the prices in the 2008/2009 RPM Third Incremental Auction.

- **EMAAC.** Although EMAAC was a constrained LDA in the 2008/2009 BRA, supply and demand curves resulted in a price less than the RTO clearing price. Supply offers in the incremental auction in EMAAC (1,142.8 MW) exceeded EMAAC demand bids (191.0 MW). The result was that all of EMAAC supply which cleared received the RTO clearing price.

- **SWMAAC.** In SWMAAC, 20.6 MW were offered into the auction while buy bids in SWMAAC totaled 237.5 MW. SWMAAC was a constrained LDA for the 2008/2009 delivery year, so the 20.6 MW was the only supply available to meet SWMAAC demand. Since supply was less than demand, the price was set by a vertical extension of the supply curve to meet demand, resulting in a clearing price of $223.85 per MW-day.

23 EMAAC was an acronym for Eastern Mid-Atlantic Area Council and SWMAAC was an acronym for Southwestern Mid-Atlantic Area Council. MAAC no longer exists as its role was taken on by Reliabilty*First* Corporation. EMAAC and SWMAAC are now regions of PJM.

Figure 6 History of Capacity prices: 1999 through 2008



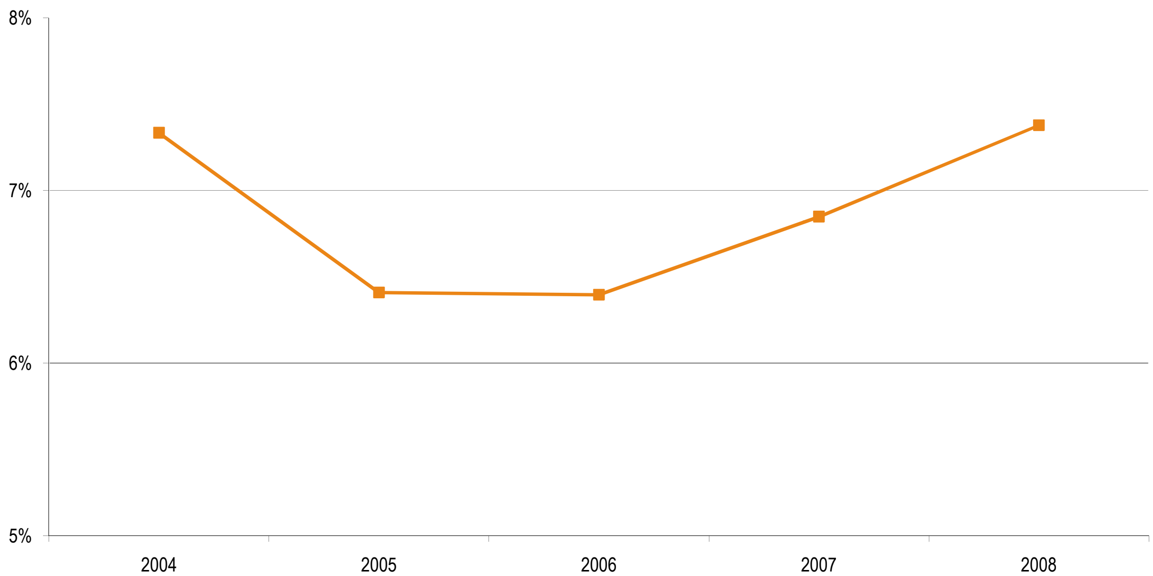
Generator Performance

- **Forced Outage Rates.** The average PJM EFORd decreased from 7.3 percent in 2005 to 6.4 percent in 2005 and 2006 and increased to 6.8 percent in 2007 and 7.4 percent in 2008.[24] The increase in EFORd from 2007 to 2008 was the result of increased forced outage rates for steam and nuclear generating units. The forced outage rates are for the entire PJM footprint.

- **Outages Outside of Management Control (OMC).** PJM permits units to use a forced outage rate (XEFORd) for purposes of selling unforced capacity in the Capacity Market, calculated using outages that are designated outside management control. The MMU questions whether the use of the OMC outage designation in this manner is reasonable, particularly given that most of the OMC outages are based on lack of fuel. A forced outage is a forced outage, from the perspective of system reliability, regardless of the cause.

24 Data are for the 12 months ended December 31, 2008, as downloaded from the PJM GADS database on January 23, 2009. Annual EFORd data presented in state of the market reports may be revised based on data submitted after the publication of the reports as generation owners may submit corrections at any time with permission from PJM GADS administrators.

Figure 7 Trends in the PJM equivalent demand forced outage rate (EFORd): Calendar years 2004 to 2008



Capacity Market Conclusion

Market Design

The wholesale power markets, in order to be viable, must be competitive and they must provide adequate revenues to ensure an incentive to invest in new capacity. A wholesale energy market will not consistently produce competitive results in the absence of local market power mitigation rules. This is the result, not of a fundamental flaw in the market design, but of the fact that transmission constraints in a network create local markets where there is structural market power. A wholesale energy market will not consistently result in adequate revenues in the absence of a carefully designed and comprehensive approach to scarcity pricing. This is a result, not of offer capping, but of the fundamentals of wholesale power markets which must carry excess capacity in order to meet externally imposed reliability rules.

Scarcity revenues to generation owners can come entirely from energy markets or they can come from a combination of energy and capacity markets. The RPM design reflects the recognition that the energy markets, by themselves and in the absence of a carefully designed expansion of scarcity pricing, will not result in adequate revenues. The RPM design provides an alternate method for collecting scarcity revenues. The revenues in the capacity market are scarcity revenues.

If the revenues collected in the RPM market are adequate, it is not essential that a scarcity pricing mechanism exist in the energy market. Nonetheless, it would be preferable to also have a scarcity pricing mechanism in the energy market because it provides direct, market-based incentives to load and generation, as long as it is designed to ensure that scarcity revenues directly offset RPM revenues. This hybrid approach would include both a capacity market and scarcity pricing in the energy market.

The definition of the capacity product is central to refining the market rules governing the sale and purchase of capacity. The current definition of capacity includes several components: the obligation to offer the energy of the unit into the day ahead market; the obligation to permit PJM to recall the energy from the unit under emergency procedures; the obligation to provide outage data to PJM; the obligation to provide energy during the defined high demand hours each year; and the obligation that the energy output from the resource be deliverable to load in PJM.

The most critical of these components of the definition of capacity is the obligation to offer the energy of the unit into the day ahead market. If buyers are to pay the high prices associated with RPM, it must be clear what they are buying and what the obligations of the sellers are. The fundamental energy market design should assure all market participants that the outcomes are competitive. This works to the ultimate advantage of all market participants including existing and prospective load and existing and prospective generation. The market rules should explicitly require that offers into the day ahead energy market be competitive, where competitive is defined to be the short run marginal cost of the units. The short run marginal cost should reflect opportunity cost when and where appropriate.

An offer that exceeds short run marginal cost is not a competitive offer in the day ahead energy market. Such an offer assumes the need to exercise market power to ensure revenue adequacy. An offer to provide energy only in an emergency is not a competitive offer in the day ahead energy market. A unit which is not capable of supplying energy consistent with its day-ahead offer should reflect an appropriate outage rather than indicating its availability to supply energy.

Capacity market design should reflect the fact that the capacity market is a mechanism for the collection of scarcity revenues and thus reflect the incentive structure of energy markets to the maximum extent possible. For example, if a generation unit does not produce power during a high price hour, it receives no revenues from the energy market. It does not receive some revenues simply for existing, it receives zero revenues. The reason that the unit does not produce energy is not relevant. It does not receive revenues if it does not produce energy even if the reason for non performance is outside management's control. That is the basic performance incentive structure of energy markets. The same performance incentive structure should be replicated in capacity market design. If a unit that is a capacity resource does not produce energy during the hours defined as critical, it will receive no energy revenues for those hours. If a unit defined as a capacity resource does not produce energy during any of the hours defined as critical, it should receive no capacity revenues. This approach to performance is also consistent with the reduction or elimination of administrative penalties associated with failure to meet capacity tests, for example.

A hybrid market design can provide scarcity revenues both via scarcity pricing in the energy market and via the capacity market. However, if there is scarcity pricing in the energy market, the market design must ensure that units receiving scarcity revenues in the capacity market do not also receive scarcity revenues in the energy market. This would be double payment of scarcity revenues. This offset must reflect the actual scarcity revenues and not those reflected in forward curves or forecasts, or those reflected in results from prior years. Scarcity revenues are episodic and unlikely to be fully reflected in historical data or in forward curves, even if such curves were based on a liquid market three years forward, which they are not, and reflected locational results, which they do not. The most straightforward way to ensure that such double payment does not occur would be to ensure that capacity resources do not receive scarcity revenues in the energy market in the first place. The settlements process can remove any scarcity revenues from payments to capacity resources and eliminate the need for a complex, uncertain, after the fact procedure for offsetting scarcity revenues in the capacity market.

Market Power

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. 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 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.

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 by limiting the exercise of market power via the application of the three pivotal supplier test.

Competitive prices are the lowest possible prices, consistent with the resource costs. But, competitive prices are not necessarily low prices. In the Capacity Market, it is essential that the cost of new entry (CONE) be based on the actual resource costs of bringing a new capacity resource into service. If RPM is to provide appropriate incentives for new entry, the marginal price signal must reflect the actual cost of new entry.

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. 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.

Results

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 examines participant behavior within that market structure. In a competitive market structure, market participants are constrained to behave competitively. The analysis examines market performance, measured by price and the relationship between price and marginal cost, that results from the interaction of market structure and participant behavior.

The MMU found serious market structure issues, but no exercise of market power in the PJM Capacity Market in 2008. 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 2008.

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.[25] Of these, PJM currently provides regulation, energy imbalance, synchronized reserve, and operating reserve – supplemental 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 resources up and down via an automatic control signal.[26] 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.

On June 1, 2008 PJM introduced the Day-Ahead Scheduling Reserve Market (DASR), as required by the settlement in the RPM case.[27] The purpose of this market is to satisfy supplemental (30-minute) reserve requirements with a market-based mechanism that allows generation resources to offer their reserve energy at a price and compensates cleared supply at the market clearing price.

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.

PJM does not provide a market for black start services, which are procured and paid zonally, but does ensure that there are adequate black start resources.

The MMU analyzed measures of market structure, conduct and performance of the PJM Regulation Market and of its two Synchronized Reserve Markets for 2008, comparing market results to 2007.

25 75 FERC ¶ 61,080 (1996).

26 Regulation is used to help control the area control error (ACE). See *2008 State of the Market Report,* Volume II, Appendix F, “Ancillary Service Markets,” for a full definition and discussion of ACE. Regulation resources were almost exclusively generating units in 2008.

27 See PJM Interconnection, L.L.C., 117 FERC ¶ 61,331 (2006).

The MMU also analyzed measures of market structure, conduct and performance of the PJM DASR Market from June 1 through December 31, 2008.

Regulation Market

There were no major structural changes to the PJM Regulation Market in 2008 which continues to be operated as a single market. On December 1, 2008, PJM implemented several changes to the Regulation Market including the introduction of the three pivotal supplier test for market power, a change to the calculation of lost opportunity cost and a change to the treatment of regulation revenues with respect to operating reserve credits.

Market Structure

- **Supply.** During 2008, 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 2008. The ratio of eligible regulation offered to regulation required averaged 2.39 throughout 2008.

- **Demand.** From January 1 through August 7, 2008, PJM calculated the regulation requirement for all hours of the day as 1.0 percent of the peak load forecast for the operating day. This requirement was established in August 2006. Beginning August 7, PJM began to calculate on-peak and off-peak regulation requirement. The on-peak requirement is equal to 1.0 percent of the forecast peak load for the PJM RTO for the day. The PJM RTO off-peak Regulation Requirement is equal to 1.0 percent of the forecast valley load for the PJM RTO for the day. The average hourly regulation demand in 2008 was 922 MW. For the winter the demand was 960 MW; for the spring it was 834 MW; for the summer it was 1,064 MW; and for the fall it was 815 MW. For the months of August through December, average off-peak regulation demand was 665 MW while average on-peak demand was 881 MW.

- **Market Concentration.** During 2008, the PJM Regulation Market had a load weighted, average Herfindahl-Hirschman Index (HHI) of 1283 which is classified as “moderately concentrated.”[28] The load weighted average HHI before August 1 (when the requirement was fixed for all hours of the day) was 1226. The load weighted average HHI after August 1 when the requirement was lower for off-peak hours, was 1397. The minimum hourly HHI was 707 and the maximum hourly HHI was 2767. The largest hourly market share in any single hour was 58 percent, and 63 percent of all hours had a maximum market share greater than 20 percent. In 2008, 82 percent of hours had three or fewer pivotal suppliers. The MMU concludes from these results that the PJM Regulation Market in 2008 was characterized by structural market power in 82 percent of the hours.

Market Conduct

- **Offers.** From January through November 2008 regulation offer prices were provided by the unit owner, applicable for the entire operating day and, with lost opportunity cost (LOC), comprised

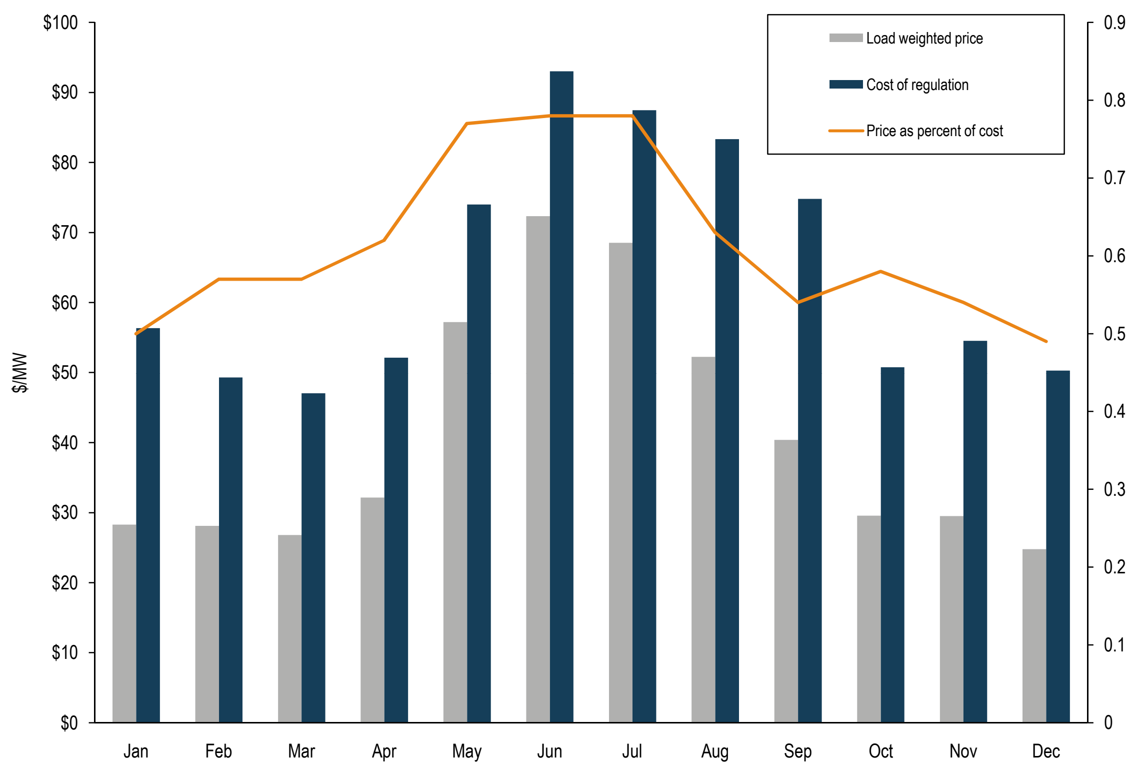
28 See the *2008 State of the Market Report*, Volume II, Section 2, “Energy Market, Part I,” at “Market Concentration” for a more complete discussion of concentration ratios and the Herfindahl-Hirschman Index (HHI).

the total offer to the Regulation Market. The regulation offer price was subject to a $100 per MWh offer cap, with the exception of the two dominant suppliers, whose offers were capped at marginal cost plus $7.50 per MWh plus LOC. All suppliers are paid the market-clearing price. Beginning December 1, 2008 PJM implemented a three pivotal supplier test in the regulation market. As part of the implementation, owners are required to submit unit specific cost based offers which may include up to a $12/MWh margin adder and owners have the option to submit price based offers. All offers remain subject to the $100 per MWh cap. All units owned by owners who fail the three pivotal supplier test for an hour are dispatched at the lesser of their cost based or price based offer. As part of the changes to the regulation market implemented on December 1, 2008, PJM no longer nets regulation revenue above offer price against operating reserve revenue and PJM now calculates lost opportunity costs using the lower of cost based or price based offers as the reference rather than the cost based offer.

Market Performance

- **Price.** For the PJM Regulation Market during 2008 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 $42.09. This represents an increase of $5.37 from the average price for regulation during 2007. From January through November 2008, 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 18 percent of all hours. On December 1, 2008, PJM implemented new Regulation Market rules that cost cap units offered by suppliers which are pivotal and allow price based offers for units whose suppliers are not.

Figure 8 Monthly load-weighted, average regulation cost and price: Calendar year 2008



Synchronized Reserve Market

There were no major structural changes to the PJM Synchronized Reserve Market in 2008.[29] Throughout 2008 PJM retained the two synchronized reserve markets it implemented on February 1, 2007. The RFC Synchronized Reserve Zone reliability requirements are set by the Reliability*First* Corporation. The Southern Synchronized Reserve Zone (Dominion) reliability requirements are set by the Southeastern Electric Reliability Council (SERC).

In September 2008, PJM made a change to the market clearing software, Synchronized Reserve and Regulation Optimizer (SPREGO), designed to improve the accuracy of Tier 1 estimates and reduce the amount of Tier 2 synchronized reserve called by PJM dispatchers after the market cleared. These additional assignments made by the dispatchers are to meet increases in required synchronized reserves that occur after needed synchronized reserve is first forecast 90 minutes before the operating hour. The changes were made to address a problem in the Synchronized Reserve Market that has been persistent since late 2007.

In mid-January 2009, PJM Market Operations took the unusual step of recalculating, revising, and reposting synchronized reserve market clearing prices for November and early December 2008. Some hours had been erroneously calculated because validation data required by a software change had not been entered. In all, nine hours were reposted. The price changes ranged from a reduction of $30.38 to a reduction of $429.83 and included one hour where there was a price increase of $11.23.

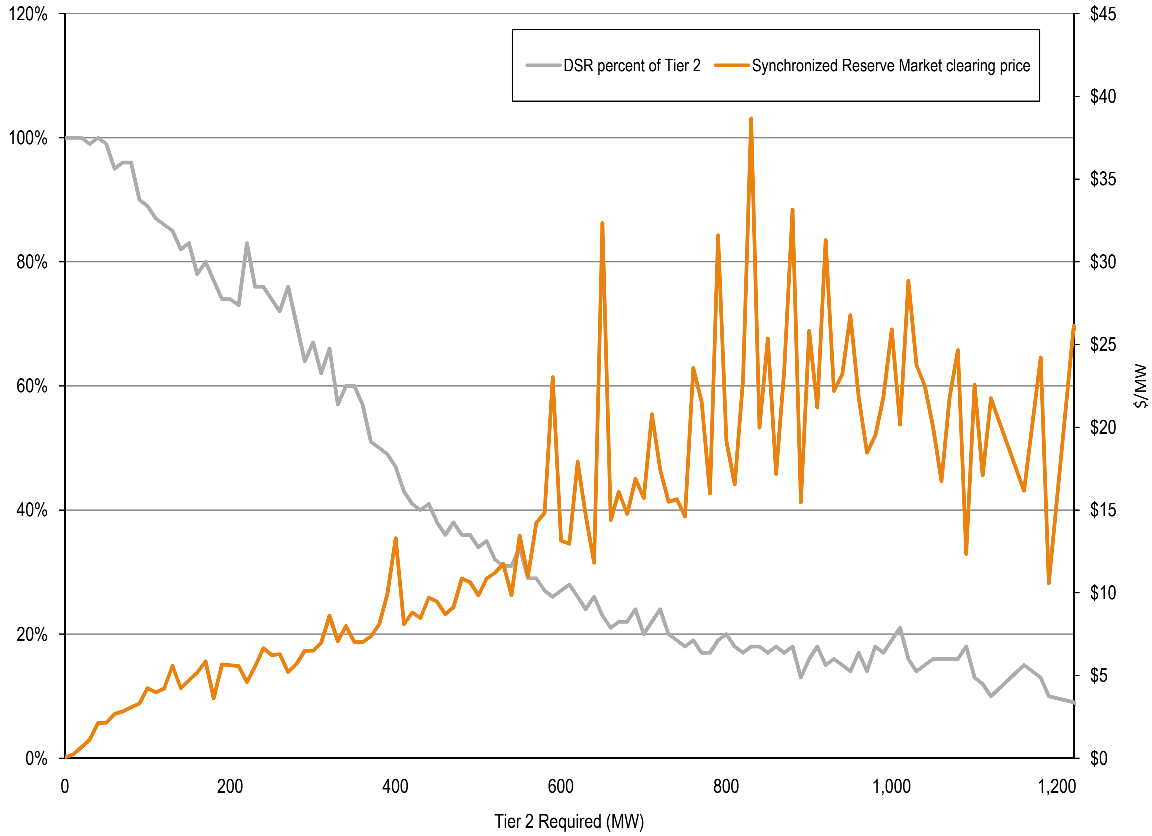
Market Structure

- **Supply.** During 2008, the offered and eligible excess supply ratio was 1.41 for the PJM Mid-Atlantic Synchronized Reserve Region.[30] The excess supply ratio is 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. Throughout 2008, the MW contribution of DSR resources to the Synchronized Reserve Market remained significant and resulted in lower overall Synchronized Reserve prices.

29 In PJM, the term, Synchronized Reserve Market, refers to Tier 2 synchronized reserve. Synchronized Reserve as it is used here is 10-minute operating reserve.

30 The Synchronized Reserve Market in the Southern Region cleared in so few hours that related data for that market is not meaningful.

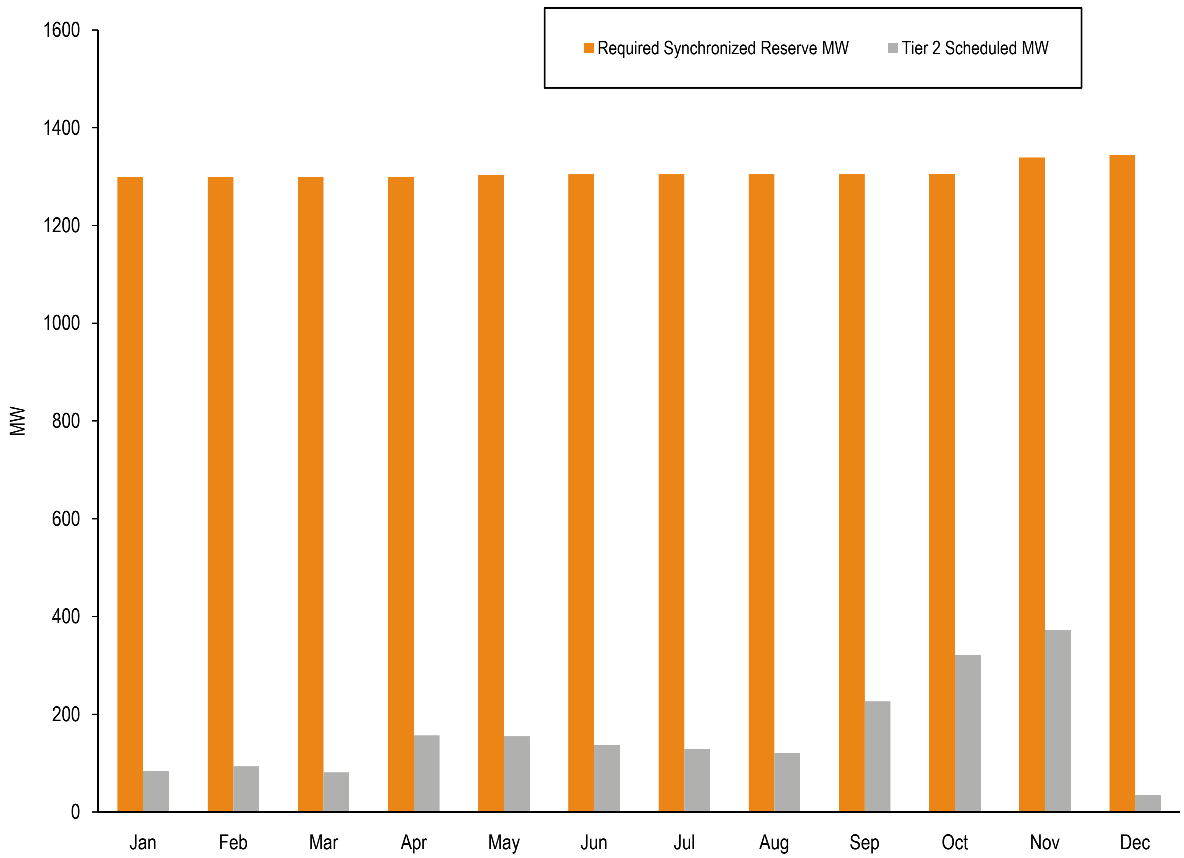
Figure 9 Required Tier 2 synchronized reserve, synchronized reserve market clearing price, and DSR percent of Tier 2



- **Demand.** The average synchronized reserve requirements were 1,310 MW for the RFC Synchronized Reserve Zone and 1,160 MW for the Mid-Atlantic Subzone. These requirements are a function of administratively determined, regional requirements established by each market zone's reliability council. Since there was usually enough Tier 1 in the RFC Synchronized Reserve Zone to cover the requirement, only 5 percent of hours cleared a Tier 2 Synchronized Reserve market in the RFC. For the Southern Synchronized Reserve Zone only 1.5 percent of the hours had a non-zero Tier 2 requirement in 2008. Market demand is less than the requirement by the amount of forecast 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 153 MW. Demand for Tier 2 Synchronized Reserve fell sharply in December as a result of a large increase in the forecast Tier 1 available. The average demand for Tier 2 synchronized reserve in the Southern Synchronized Reserve Zone was 1.5 MW. All demand for Tier 2 in the Southern Synchronized Reserve Zone was satisfied by 15-minute quick start units. A Southern Synchronized Reserve Zone market did not clear in any hours in 2008.

  The purchase of additional Tier 2 synchronized reserves by dispatchers after synchronized reserve market settlement continued to be an issue in 2008. In 2008, 44 percent of all Tier 2 synchronized reserves were added after the market cleared. It is clear that, in actual operations, PJM dispatch identifies a need for more Tier 2 synchronized reserve, or differently located synchronized reserve, than is being forecast and scheduled through the Tier 2 Synchronized Reserve Market. It is clear that there is a difference in the calculation of the need for Tier 2 synchronized reserves between the market solution and the operators. The reason remains under investigation.

Figure 10 RFC Synchronized Reserve Zone monthly average synchronized reserve required vs. Tier 2 scheduled MW: Calendar year 2008



- **Market Concentration.** Although lower than in 2007, market concentration in the Tier 2 Synchronized Reserve Markets remained high in 2008. The average load weighted cleared Synchronized Reserve Market HHI for the Mid-Atlantic Subzone of the RFC Synchronized Reserve Zone throughout 2008 was 2844. Slightly less than one percent of all hours had a market share of 100 percent. In 56 percent of hours the maximum market share was greater than 40 percent (compared to 76 percent of hours in 2007). In the Mid-Atlantic Subzone of the RFC Synchronized Reserve Market, in 2008, 96 percent of hours had three or fewer pivotal suppliers. The MMU concludes from these results that the PJM Synchronized Reserve Markets in 2008 were characterized by structural market power.

Market Conduct

- **Offers.** The offer price is provided by the unit owner, is applicable for the entire operating day and, with lost opportunity cost calculated by PJM, comprises the merit order price to the Synchronized Reserve Market. The synchronized reserve offer made by the unit owner is subject to an offer cap of marginal cost plus $7.50 per MW, 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 $10.65 per MW in 2008, a $5.63 per MW decrease from 2007.

- **Demand.** 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. This continued throughout 2008. The increase in out of market purchases indicates that the Synchronized Reserve Market is not functioning to adequately coordinate supply and demand. It is not clear why the demand identified in the market solution is consistently less than the demand identified by the system operators.

- **DSR.** Demand side resources began participating in the Synchronized Reserve Markets in August 2006. Participation of demand response grew significantly in late 2007, leveled off through August of 2008 and rose significantly in September through December of 2008. In 32 percent of hours during 2008 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 2008.

DASR

On June 1, 2008 PJM introduced the Day-Ahead Scheduling Reserve Market (DASR), as required by the RPM settlement.[31] The purpose of this market is to satisfy supplemental (30-minute) reserve requirements with a market-based mechanism that allows generation resources to offer their reserve energy at a price and compensates cleared supply at a single market clearing price. The DASR 30-minute reserve requirements are determined by the reliability region.[32] The RFC and Dominion DASR requirements are added together to form a single RTO DASR Requirement which is obtained via the DASR Market. The requirement is applicable for all hours of the operating day. If the DASR Market does not result in procuring adequate scheduling reserves, PJM is required to schedule additional operating reserves.

31 See PJM Interconnection, L.L.C., 117 FERC ¶ 61,331 (2006).
32 PJM Manual 13, Emergency Requirements, Rev 35, 11/07/2008; pp 11-12.

Market Structure

The DASR Market in 2008 had three pivotal suppliers in a monthly average of 45 percent of all hours. The number of hours in which the DASR Market had three pivotal suppliers declined in November and December. The MMU concludes from these results that the PJM DASR Market in 2008 was characterized by structural market power.

Market Conduct

In December, about 6 percent of all units engaged in economic withholding from the DASR Market by providing high offer prices. Conversely, about 48 percent of units had offers of $0.00, either by choice or by default.

Market Performance

For June 2008 through December 2008, the load weighted price of DASR was $0.26. DASR prices declined in the last three months of 2008. Demand side resources began to offer and clear in the DASR Market in November and became significant in December.

Black Start

Black start service is necessary to help ensure the reliable restoration of the grid following a black out. Black start service is the ability of a generating unit to start without an outside electrical supply, or is the demonstrated ability of a generating unit with a high operating factor to automatically remain operating at reduced levels when disconnected from the grid.[33]

Individual transmission owners, with PJM, identify the black start units included in each transmission owner's system restoration plan. PJM defines required black start capability zonally and ensures the availability of black start service by charging transmission customers according to their zonal load ratio share and compensating black start unit owners.

PJM does not have a market to provide black start reserve, but compensates black start resource owners for all costs associated with providing this service, as defined in the tariff. For 2008, charges to PJM members for providing black start services were just over $13 million.

As a consequence of PJM's filing to revise its formula rate for black start service to allow for the recovery of the costs of compliance with Critical Infrastructure Protection standards, these costs likely will increase substantially. The revised rates also better match the sellers' commitment period with the period for cost recovery.

The MMU recommends that PJM, FERC and state regulators reevaluate the way in which black start service is procured in order to ensure that procurement is done in a globally least cost manner.

33 PJM, "Open Access Transmission Tariff" (OATT), "Common Service Provisions", Second Revised Sheet No. 33.01 (Effective March 1, 2007).

Ancillary Services 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 2008, 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, where the MMU finds that prices were set by offers above the competitive level in 18 percent of the hours. The absence of a definitive conclusion is a result of the fact that the cost data are based on MMU estimates rather than data submitted by market participants. It is expected that the application of the three pivotal supplier test will mean that the results of the Regulation Market will be competitive in 2009.

In 2008, PJM and its stakeholders addressed the issue of market power mitigation for the Regulation Market in the Three Pivotal Supplier Task Force (TPSTF), which was convened pursuant to PJM's 2007 Strategic Report to review market power mitigation issues.[34] The TPSTF achieved a consensus supporting the application of the three pivotal supplier (TPS) test to the Regulation Market, provided that three adjustments to the rules were included, all of which increased margins for regulation units. PJM filed the proposed revisions on October 1, 2008.[35] A number of parties filed comments, including the MMU on October 20, 2008.[36] The MMU supported the consensus but requested that the Commission direct the MMU to report on the three adjustments to the rules: increasing the current $7.50 adder to cost based offers to $12; modifying the calculation of opportunity costs to use the lower of cost based or price based offers as the reference; and eliminating the netting of revenues from the Regulation Market from make whole balancing operating reserve payments. The Commission, in accepting PJM's filing on November 26, 2008, directed the MMU to prepare a report due on November 26, 2009.[37]

On December 1, 2008, the three pivotal supplier test was implemented in the Regulation Market to address the identified market power problems. The one month of data for December 2008, is inadequate to permit a meaningful assessment of the impact of the modifications on the PJM Regulation Market.

The implementation of the three pivotal supplier test is consistent with the longstanding MMU recommendation 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. This more flexible and real-time approach to mitigation represents an improvement over the approach to mitigation which had been in place from August 2005 through November 2008 which required cost based offers from the two dominant suppliers at all times. The three pivotal supplier 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

34 See PJM 2007 Strategic Report at 65 (April 2, 2007). This report is posted on PJM's Website at: http://www2.pjm.com/documents/downloads/strategic-responses/report/20070402-pjm-strategic-report.pdf.

35 PJM submitted its initial filing in FERC Docket No. ER09-13-000.

36 Comments and Motion for Leave to Intervene of the Independent Market Monitor for PJM, Docket No. ER09-13-000. These comments are posted on the Monitoring Analytics' Website at http://www.monitoringanalytics.com.

37 *PJM Interconnection, L.L.C.*, 125 FERC ¶ 61,231, at P 18 (2008).

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 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.

The issue of Tier 2 synchronized reserve purchases after market clearing began in the last quarter of 2007. Beginning in October and increasing substantially in November and December 2007, there was an increase in the amount of combustion turbine, synchronized condenser MW added by PJM market operations to the Synchronized Reserve Market after market clearing.

In 2008 PJM continued to rely on non-economic, out of market Tier 2 resources added to the resources procured in the synchronized reserve market. Tier 2 synchronized reserve added after the market cleared accounted for approximately 44 percent of total Tier 2 synchronized reserve purchased in 2008. In September, PJM attempted to address this issue by improving the forecast of Tier 1. PJM added a second Tier 1 estimate performed 30 minutes prior to the operating hour. This did not succeed in reducing the amount of Tier 2 added after market clearing.

In December, a significant increase in the amount of estimated Tier 1 reduced the amount of Tier 2 needed to meet the required synchronized reserve. The increase in the amount of estimated Tier 1 appears to have been the result of a mistake in identifying available Tier 1 resources prior to December. The increase in Tier 1 resources did not reduce the amount of Tier 2 synchronized reserve added to the synchronized reserve market after market clearing. In December, the amount of Tier 2 cleared fell substantially, while the proportion of synchronized reserve added out of market increased significantly.

The continued reliance on out of market purchases indicates that the Synchronized Reserve Market is not functioning to coordinate supply and demand in a way consistent with the need identified for these reserves in real time by PJM operations. It is clear that, in actual operations, PJM dispatch identifies a need for more Tier 2 synchronized reserve, or differently located synchronized reserve, than is being forecast and scheduled through the Tier 2 Synchronized Reserve Market. It is clear that there is a difference in the calculation of the need for Tier 2 synchronized reserves in the Mid-Atlantic subzone between the market solution and the operators. The reason remains under investigation.

The MMU concludes that the DASR Market is not structurally competitive, based on the results in 2008. The MMU recommends that the DASR Market rules be modified to incorporate the application of the three pivotal supplier test. The MMU also concludes that the DASR Market results were competitive in 2008.

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, although the implementation of the three pivotal supplier test in the Regulation Market on December 1 is expected to improve the results. The MMU concludes that the Synchronized Reserve Markets' results were competitive and that the differences between the market demand and the operational demand for Synchronized Reserves need to be addressed. The MMU concludes that the DASR Market's 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.[38] The result is that the price of energy in the constrained area is higher than in the unconstrained area because of the combination of transmission limitations and the cost of local generation. Locational marginal prices (LMPs) reflect the price of the lowest-cost resources available to meet loads, taking into account actual delivery constraints imposed by the transmission system. Thus LMP is an efficient way to price energy when transmission constraints exist. Congestion reflects this efficient pricing.

Congestion reflects the underlying characteristics 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 require direct competition between investments in transmission and generation. The transmission system provides a physical hedge against congestion. The transmission system is paid for by firm load and, as a result, firm load receives the corollary financial hedge in the form of Auction Revenue Rights (ARRs) and/or Financial Transmission Rights (FTRs). While the transmission system and, therefore, ARRs/FTRs are not guaranteed to be a complete hedge against congestion, ARRs/FTRs do provide a substantial offset to the cost of congestion to firm load.[39]

The MMU analyzed congestion and its influence on PJM markets during 2008.

Congestion Cost

- **Total Congestion.** Total congestion costs increased by $271 million or 15 percent, from $1.846 billion in calendar year 2007 to $2.117 billion in calendar year 2008. Day-ahead congestion costs increased by $586 million or 28 percent, from $2.075 billion in calendar year 2007 to $2.661 billion in calendar year 2008. Balancing congestion costs decreased by $315.6 million or 137 percent, from -$229 million in calendar year 2007 to -$544.6 million in calendar year 2008. 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 2008, as was the case in 2007. Total PJM billings for 2008 were $34.306 billion, a 12 percent increase from the $30.556 billion billed in 2007.

38 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 the next unit in merit order cannot be used and a higher cost unit must be used in its place.

39 See the *2008 State of the Market Report*, Volume II, Section 8, "Financial Transmission and Auction Revenue Rights," at "ARR and FTR Revenue and Congestion."

Table 4 Total annual PJM congestion (Dollars (Millions)): Calendar years 2003 to 2008

	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	$1,846	15%	$30,556	6%
2008	$2,117	15%	$34,306	6%
Total	$8,872		$124,037	7%

- **Monthly Congestion.** Fluctuations in monthly congestion costs continued to be substantial. In 2008, these differences were driven by varying load and energy import levels, different patterns of generation, weather-induced changes in demand and variations in congestion frequency on constraints affecting large portions of PJM load.

Congestion Component of LMP and Facility or Zonal Congestion

- **Congestion Component of Locational Marginal Price (LMP).** To provide an indication of the geographic dispersion of congestion costs, the congestion component of LMP (CLMP) was calculated for control zones in PJM. Price separation between eastern, southern and western control zones in PJM was primarily a result of congestion on the AP South interface. This interface had the effect of increasing prices in eastern and southern 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 2007, congestion frequency was significantly higher in the Day-Ahead Market than in the Real-Time Market in 2008.[40] Day-ahead congestion frequency increased in calendar year 2008 compared to 2007. In 2008, there were 74,742 day-ahead, congestion-event hours compared to 62,616 congestion-event hours in 2007. Day-ahead, congestion-event hours increased on PJM transmission lines, transformers and the flowgates between PJM and the Midwest ISO while congestion frequency on internal PJM interfaces decreased in 2008 compared to 2007. Real-time congestion frequency increased in calendar year 2008 compared to 2007. In 2008, there were 21,651 real-time, congestion-event hours compared to 19,527 congestion-event hours in 2007. Real-time, congestion-event hours increased on PJM transmission lines, transformers and on the flowgates between PJM and the Midwest ISO, while interfaces saw decreases. The AP South Interface was the largest contributor to congestion costs in 2008. With $558 million in total congestion costs, it accounted for 26 percent of the total PJM congestion costs in 2008. The top five constraints in terms of congestion costs together contributed $1.282 billion, or 61 percent, of the total PJM congestion costs in 2008. The top five constraints included the AP South Interface, the

40 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 *2008 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.

Cloverdale – Lexington line, the Mount Storm – Pruntytown line and the Bedington – Black Oak and West interface constraints.

Table 5 Congestion summary (By facility type): Calendar year 2008

	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	$9.6	($14.3)	$11.8	$35.7	($7.2)	$3.5	($44.8)	($55.5)	($19.9)	2,417	2,031
Interface	$368.3	($579.2)	$44.7	$992.2	($18.2)	$20.3	($16.3)	($54.8)	$937.4	8,866	2,196
Line	$597.5	($423.0)	$120.0	$1,140.6	($129.1)	$27.6	($146.4)	($303.1)	$837.4	50,637	12,710
Transformer	$299.9	($139.6)	$29.9	$469.4	($71.4)	$27.7	($32.0)	($131.2)	$338.2	12,822	4,714
Unclassified	$10.9	($10.6)	$2.0	$23.4	$0.0	$0.0	($0.0)	($0.0)	$23.4	NA	NA
Total	$1,286.1	($1,166.7)	$208.4	$2,661.2	($225.9)	$79.2	($239.5)	($544.6)	$2,116.6	74,742	21,651

- **Zonal Congestion.** In calendar year 2008, the AP Control Zone experienced the highest congestion costs of the control zones in PJM. The $487.1 million in congestion costs in the AP Control Zone represented a 9 percent increase from the $448.6 million in congestion costs the zone had experienced in 2007. The AP South Interface contributed $145.3 million, or 30 percent of the total AP Control Zone congestion cost. The Dominion Control Zone had the second highest congestion cost in PJM in 2008. The $322.6 million in congestion costs in the Dominion Control Zone represented an 11 percent increase from the $290.8 million in congestion costs the zone had experienced in 2007. The AP South Interface contributed $177.1 million, or 55 percent of the total Dominion Control Zone congestion cost.

Table 6 Congestion cost summary (By control zone): Calendar year 2008

	Congestion Costs (Millions)								
	Day Ahead				Balancing				
Control Zone	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total
AECO	$111.1	$31.8	$1.2	$80.5	($12.9)	$8.1	($2.0)	($23.0)	$57.5
AEP	($367.1)	($671.0)	$15.7	$319.6	($85.2)	$4.0	($6.9)	($96.1)	$223.6
AP	$124.4	($391.6)	$38.7	$554.7	($13.6)	$21.5	($32.6)	($67.7)	$487.1
BGE	$314.3	$245.3	$3.2	$72.2	$10.1	($14.2)	($4.5)	$19.8	$92.0
ComEd	($480.9)	($820.9)	$4.8	$344.8	($54.9)	$0.4	($5.2)	($60.6)	$284.2
DAY	($45.5)	($56.5)	$0.2	$11.1	$3.5	$2.6	($0.3)	$0.6	$11.8
DLCO	($159.2)	($249.2)	$1.1	$91.2	($49.4)	$22.2	$0.3	($71.3)	$19.9
Dominion	$337.2	$5.2	$33.0	$364.9	($9.3)	($0.9)	($33.9)	($42.3)	$322.6
DPL	$149.5	$54.1	$1.1	$96.5	$8.0	$6.2	($1.8)	($0.1)	$96.4
External	($59.5)	($51.5)	$35.6	$27.5	($31.6)	($36.4)	($107.5)	($102.7)	($75.2)
JCPL	$260.6	$72.1	$9.1	$197.6	($0.0)	($0.4)	($8.9)	($8.5)	$189.0
Met-Ed	$104.9	$104.5	$3.3	$3.8	$2.3	$0.8	$10.4	$12.0	$15.7
PECO	$70.9	$118.1	$0.5	($46.8)	($0.5)	$15.5	($0.7)	($16.8)	($63.5)
PENELEC	($43.2)	($224.3)	$4.8	$186.0	($4.8)	$13.6	($1.4)	($19.9)	$166.1
Pepco	$642.4	$436.2	$8.4	$214.7	$6.6	($3.7)	($9.1)	$1.2	$215.9
PPL	$29.0	$39.9	$12.7	$1.8	$0.2	$5.6	($5.2)	($10.6)	($8.8)
PSEG	$287.3	$190.9	$33.3	$129.7	$5.2	$34.5	($27.9)	($57.3)	$72.5
RECO	$10.0	$0.1	$1.5	$11.4	$0.5	($0.2)	($2.2)	($1.5)	$9.9
Total	$1,286.1	($1,166.7)	$208.4	$2,661.2	($225.9)	$79.2	($239.5)	($544.6)	$2,116.6

Economic Planning Process

- **Transmission and Markets.** As a general matter, transmission investments have not been fully incorporated into competitive markets. The construction of new transmission facilities can have significant impacts on energy and capacity markets, but there is no market mechanism in place that would require direct competition between transmission and generation to meet loads in an area. While the RPM construct does provide that qualifying transmission upgrades may be submitted as offers, there have been no such offers. More generally, network transmission is not built based directly on market signals because the owners of network transmission are compensated through a non market mechanism. PJM has taken a first step towards integrating transmission investments into the market through the use of economic evaluation metrics. Economic evaluation metrics can be used to determine whether there are positive economic benefits associated with an investment in transmission that might warrant the investment even when it is not required for reliability. The goal of transmission planning should ultimately be the incorporation of transmission investment decisions into market driven processes as much as possible.

- **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. The FERC has recently accepted the latest PJM filing in Docket No. ER06-1474.

Congestion 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 $271 million or 15 percent, from $1.846 billion in calendar year 2007 to $2.117 billion in calendar year 2008. Day-ahead congestion costs increased by $586 million or 28 percent, from $2.075 billion in calendar year 2007 to $2.661 billion in calendar year 2008. Balancing congestion costs decreased by $315.6 million or 138 percent, from -$229 million in calendar year 2007 to -$544.6 million in calendar year 2008. 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 2008, there were 74,742 congestion-event hours compared to 62,616 congestion-event hours in 2007. In the Real-Time Energy Market in 2008, there were 21,651 congestion-event hours compared to 19,527 congestion-event hours in 2007.

As a result of the geographic growth of PJM, efficient redispatch displaced the less efficient management of power flows across multiple borders via transmission loading relief (TLR) procedures and ramp limits. (Power flows across the new, external borders continue to be managed, in part, via TLRs 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, but not total, hedge against congestion. ARR and FTR revenues hedged 97.4 percent of the total congestion costs in the Day-Ahead Energy Market and the balancing energy market within PJM for the 2007 to 2008 planning period. For the first seven months of the 2008 to 2009 planning period, ARR and FTR revenue hedged 97.2 percent of the total congestion costs within PJM.[41] FTRs were paid at 100 percent of their target allocation for the planning year ended May 31, 2008, and at 99.6 percent of their target allocation for the first seven months of the current planning year.

One constraint accounted for over a quarter of total congestion costs in 2008 and the top five constraints accounted for nearly two-thirds of total congestion costs. The AP South interface displaced the Bedington – Black Oak interface as the largest contributor to congestion costs in 2008 due to system upgrades on the Bedington – Black Oak circuit in December 2007 and the

41 See the *2008 State of the Market Report*, Volume II, Section 8, "Financial Transmission and Auction Revenue Rights," at Table 8-28, "ARR and FTR congestion hedging: Planning periods 2007 to 2008 and 2008 to 2009."

associated redefinition of the AP South interface on September 1, 2008.[42] The Bedington – Black Oak constraint has been a persistent source of large congestion costs for several years, but decreased in both congestion costs and frequency in 2008. The AP South interface is now the primary west to east transfer constraint.

The congestion metric requires careful review. Net congestion, which includes both load congestion payments and generation congestion credits, is not a good measure of the congestion costs paid by load from the perspective of the wholesale market.[43] While total congestion costs represent the overall charge or credit to a zone, the components of congestion costs measure the extent to which load or generation bear total congestion costs. Load congestion payments, when positive, measure the total congestion cost to load in an area. Load congestion payments, when negative, measure the total congestion credit to load in an area. Negative load congestion payments result when load is on the lower priced side of a constraint or constraints. For example, congestion across the AP South interface means lower prices in western control zones and higher prices in eastern and southern control zones. Load in western control zones will benefit from lower prices and receive a congestion credit (negative load congestion payment). Load in the eastern and southern control zones will incur a congestion charge (positive load congestion payment). The reverse is true for generation congestion credits. Generation congestion credits, when positive, measure the total congestion credit to generation in an area. Generation congestion credits, when negative, measure the total congestion cost to generation in an area. Negative generation congestion credits result when generation is on the lower priced side of a constraint or constraints. For example, congestion across the AP South interface means lower prices in the western control zones and higher prices in the eastern and southern control zones. Generation in the western control zones will receive lower prices and incur a congestion charge (negative generation congestion credit). Generation in the eastern and southern control zones will receive higher prices and receive a congestion credit (positive generation congestion credit).

As an example, total congestion in 2008 in PJM was $2.117 billion, which was comprised of load congestion payments of $1.060 billion, negative generation credits of $1.089 billion and explicit congestion of -$31.1 million.

42 See "APSouth Transfer Interface," PJM Presentation to the Markets Implementation Committee (July 23, 2008) <http://www.pjm.com/~/media/committees-groups/committees/mic/20080723-item-08-apsouth-interface-changes.ashx>(554.44 kb)

43 The actual congestion payments by retail customers are a function of retail ratemaking policies and may or may not reflect an offset for congestion credits.

Financial Transmission and Auction Revenue Rights

Financial Transmission Rights (FTRs) and Auction Revenue Rights (ARRs) give transmission service customers and PJM members an offset against congestion costs in the Day-Ahead Energy Market. An FTR provides the holder with revenues, or charges, equal to the difference in congestion prices in the Day-Ahead Energy Market across the specific FTR transmission path. An ARR is a related product that provides the holder with revenues, or charges, based on the price differences across the specific ARR transmission path that result from the Annual FTR Auction. FTRs and ARRs provide a hedge against congestion costs, but neither FTRs nor ARRs provide a guarantee that transmission service customers will not pay congestion charges. ARR and FTR holders do not need to physically deliver energy to receive ARR or FTR credits and neither instrument represents a right to the physical delivery of energy.

In PJM, FTRs have been available to network service and long-term, firm, point-to-point transmission service customers as a hedge against congestion costs since the inception of locational marginal pricing (LMP) on April 1, 1998. Effective June 1, 2003, PJM replaced the allocation of FTRs with an allocation of ARRs and an associated Annual FTR Auction.[44] 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 *2008 State of the Market Report* focuses on the annual ARR allocations, the Annual FTR Auctions and the Monthly Balance of Planning Period FTR Auctions during two FTR/ARR planning periods: the 2007 to 2008 planning period which covers June 1, 2007, through May 31, 2008, and the 2008 to 2009 planning period which covers June 1, 2008, through May 31, 2009. The *2008 State of the Market Report* also analyzes the results of the 2009 to 2012 Long Term FTR Auction that covers three consecutive planning periods: June 1, 2009 through May 31, 2010, June 1, 2010 through May 31, 2011 and June 1, 2011 through May 31, 2012.

Financial Transmission Rights

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 runs a Long Term FTR Auction for the three consecutive planning years immediately

44 87 FERC ¶ 61,054 (1999).

following the planning year during which the Long Term FTR Auction is conducted. The first Long Term FTR Auction was conducted during the 2008 to 2009 planning period and covers three consecutive planning periods between 2009 and 2012. In addition, PJM administers a secondary bilateral market to allow participants to buy and sell existing FTRs. FTR products include FTR obligations and FTR options. FTR options are not available in the Long Term FTR Auction. For each time period, there are three FTR products: 24-hour, on peak and off peak. FTRs have terms varying from one month to three years. 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 2009 to 2012 Long Term FTR Auction include the East Sayre — North Waverly and the Farmers Valley — Two Mile lines. The principal binding constraints limiting the supply of FTRs in the Annual FTR Auction for the 2008 to 2009 planning period include the Double Toll Gate — Old Chapel line and the AP South Interface.[45] Market participants can also sell FTRs. In the 2009 to 2012 Long Term FTR Auction, total FTR sell offers were 15,757 MW. In the Annual FTR Auction for the 2008 to 2009 planning period, total FTR sell offers were 83,453 MW, down from 117,199 MW during the 2007 to 2008 planning period. In the Monthly Balance of Planning Period FTR Auctions for the first seven months (June through December 2008) of the 2008 to 2009 planning period, there were 1,436,957 MW of FTR sell offers.

- **Demand.** There is no limit on FTR demand in any FTR auction. In the 2009 to 2012 Long Term FTR Auction, total FTR buy bids were 803,911 MW. In the Annual FTR Auction for the 2008 to 2009 planning period, total FTR buy bids were 2,181,273 MW, down from 2,223,687 MW during the 2007 to 2008 planning period. Total FTR self scheduled bids were 72,851 MW for the 2008 to 2009 planning period, an increase from 71,360 MW for the 2007 to 2008 planning period. In the Monthly Balance of Planning Period FTR Auctions for the first seven months (June through December 2008) of the 2008 to 2009 planning period, total FTR buy bids were 7,593,736 MW.

- **FTR Credit Issues.** Six participants had FTR related payment obligations in default in 2008. Three of those participants had defaulted on their FTR related payment obligations in 2007. There were four participants who defaulted in 2007, after accounting for collateral. The magnitude of the defaults was the result of both the size of the FTR positions defaulted and of the PJM credit policies, which did not require sufficient collateral to cover the participants' losses. The 2007 defaults made it clear that PJM credit polices related to FTRs and particularly to counter flow FTRs were inadequate. PJM made multiple filings in 2008 to reform its credit policies, focusing particularly on ensuring an appropriate level of credit to cover positions acquired by market participants in counter flow FTRs. The defaults also raised potential market gaming issues, which were addressed, in part, in a PJM filing.[46] These are being investigated.

- **Patterns of Ownership.** The ownership concentration of cleared FTR buy bids resulting from the 2008 to 2009 Annual FTR Auction was low to moderate for FTR obligations and high for FTR options. 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

45 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 or the 2008 to 2009 planning period. For additional information on the integrations, their timing and their impact on the footprint of the PJM service territory, see the *2008 State of the Market Report,* Volume II, Appendix A, "PJM Geography."

46 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).

auction. In order to evaluate the ownership of prevailing flow and counter flow 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 more than half of prevailing flow Annual FTRs while financial entities own almost three quarters of counter flow Annual FTRs. The ownership of all Annual FTRs is about evenly split between physical and financial entities. Financial entities own almost two thirds of prevailing flow Long Term FTRs and more than half of counter flow Long Term FTRs. Financial entities own about 61 percent of all Long Term FTRs. Financial entities own two thirds of prevailing flow and about three quarters of counter flow Monthly Balance of Planning Period FTRs. Overall, financial entities own about 70 percent of all Monthly Balance of Planning Period FTRs.

Market Performance

- **Volume.** The 2009 to 2012 Long Term FTR Auction cleared 52,369 MW (6.5 percent of demand) of FTR buy bids and 1,010 MW (6.4 percent) of FTR sell offers. For the 2008 to 2009 planning period, the Annual FTR Auction cleared 204,349 MW (9.4 percent) of FTR buy bids, down from 208,637 MW (9.4 percent of demand) for the 2007 to 2008 planning period. The Annual FTR Auction also cleared 4,534 MW (5.4 percent) of FTR sell offers for the 2008 to 2009 planning period, down from 6,495 MW (5.5 percent) for the 2007 to 2008 planning period. For the first seven months of the 2008 to 2009 planning period, the Monthly Balance of Planning Period FTR Auctions cleared 545,189 MW (7.2 percent) of FTR buy bids and 183,322 MW (12.8 percent) of FTR sell offers.

- **Price.** In the 2009 to 2012 Long Term FTR Auction, 90.7 percent of the Long Term FTRs were purchased for less than $1 per MWh and 94.5 percent for less than $2 per MWh. The weighted-average prices paid for Long Term buy-bid FTRs were $0.76 per MWh for 24-hour FTRs, $0.10 per MWh for on peak FTRs and $0.01 per MWh for off peak FTRs. For the 2008 to 2009 planning period, 83.5 percent of the Annual FTRs were purchased for less than $1 per MWh and 88.8 percent for less than $2 per MWh. For the 2008 to 2009 planning period, the weighted-average prices paid for annual buy-bid FTR obligations were $1.96 per MWh for 24-hour FTRs, $0.55 per MWh for on peak FTRs and $0.26 per MWh for off peak FTRs. Comparable, weighted-average prices paid for annual buy-bid FTR obligations for the 2007 to 2008 planning period were $0.35 per MWh for 24-hour FTRs and $0.57 per MWh for on peak FTRs and $0.47 per MWh for off peak FTRs. The weighted-average prices paid for 2008 to 2009 planning period annual buy-bid FTR obligations and options were $0.69 per MWh and $0.24 per MWh, respectively, compared to $0.47 per MWh and $0.37 per MWh, respectively, in the 2007 to 2008 planning period.[47] The weighted-average price paid for buy-bid FTRs in the Monthly Balance of Planning Period FTR Auctions for the first seven months of the 2008 to 2009 planning period was $0.35 per MWh, compared with $0.21 per MWh in the Monthly Balance of Planning Period FTR Auctions for the full 12-month 2007 to 2008 planning period.

47 Weighted-average prices for FTRs in the Long Term FTR Auction, 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 2008 to 2009 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 (4,064 hours) and off peak (4,696 hours).

- **Revenue.** The 2009 to 2012 Long Term FTR Auction generated $38.93 million of net revenue for all FTRs. The Annual FTR Auction generated $2,422.55 million of net revenue for all FTRs during the 2008 to 2009 planning period, up from $1,698.03 million for the 2007 to 2008 planning period. The Monthly Balance of Planning Period FTR Auctions generated $62.2 million in net revenue for all FTRs during the first seven months of the 2008 to 2009 planning period.

- **Revenue Adequacy.** FTRs were 100 percent revenue adequate for the 2007 to 2008 planning period. FTRs were paid at 99.6 percent of the target allocation level for the first seven months of the 2008 to 2009 planning period. Congestion revenues are allocated to FTR holders based on FTR target allocations. PJM collected $1,354.8 million of FTR revenues during the first seven months of the 2008 to 2009 planning period and $2,059.2 million during the 2007 to 2008 planning period. For the first seven months of the 2008 to 2009 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 Northern Illinois Hub and the Pepco Control Zone, respectively.

Auction Revenue Rights

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 2008 to 2009 planning period were the AP South Interface and the Cedar Grove — Clifton line. A new ARR product was added for the 2007 to 2008 planning period. Long Term ARRs are in effect for 10 consecutive planning periods and are available in Stage 1A of the annual ARR allocation. Residual ARRs were also introduced and are available to holders with prorated Stage 1A or 1B ARRs if additional transmission capability is added during the planning period.

- **Demand.** Total demand in the annual ARR allocation was 140,668 MW for the 2008 to 2009 planning period with 64,546 MW bid in Stage 1A, 27,291 MW bid in Stage 1B and 48,831 MW bid in Stage 2. This is down from 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. ARR demand is limited by the total amount of network service and firm point-to-point transmission service.

- **ARR Reassignment for Retail Load Switching.** When retail load switches among load-serving entities (LSEs), a proportional share of the ARRs and their associated revenue are reassigned from the LSE losing load to the LSE gaining load. ARR reassignment occurs only if the LSE losing load has ARRs with a net positive economic value. An LSE gaining load in the same control zone is allocated a proportional share of positively valued ARRs within the control zone based on the shifted load. There were 10,017 MW of ARRs associated with approximately $353,300 per MW-day of revenue that were reassigned in the first seven months of the 2008 to 2009 planning period.

Market Performance

- **Volume.** Of 140,668 MW in ARR requests for the 2008 to 2009 planning period, 112,011 MW (79.6 percent) were allocated. There were 64,520 MW allocated in Stage 1A, 26,685 MW allocated in Stage 1B and 20,806 MW allocated in Stage 2. Eligible market participants self scheduled 72,851 MW (65.0 percent) of these allocated ARRs as Annual FTRs. 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.

- **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 2008 to 2009 planning period, ARR holders will receive $2,361.3 million in ARR credits, with an average hourly ARR credit of $2.41 per MWh. During the 2008 to 2009 planning period, the ARR target allocations were $2,361.3 million while PJM collected $2,484.8 million from the combined Annual and Monthly Balance of Planning Period FTR Auctions through December 31, 2008, making ARRs revenue adequate. During the 2007 to 2008 planning period, ARR holders received $1,640.5 million in ARR credits, with an average hourly ARR credit of $1.73 per MWh. For the 2007 to 2008 planning period, the ARR target allocations were $1,640.5 million while PJM collected $1,736.1 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 2008 to 2009 planning period, some of the requested ARRs were prorated as a result of binding transmission constraints. For the 2008 to 2009 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 605.4 MW of Stage 1B ARRs denied to participants whose requested ARRs affected that binding transmission constraint. 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.

- **ARRs and FTRs as a Hedge against 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 to the congestion costs experienced by these ARR holders. The second is to compare the revenue received by FTR holders to 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 2007 to 2008 planning period, total ARR and FTR revenues hedged 97.4 percent of the congestion costs within PJM. For the first seven months of the 2008 to 2009 planning period, all ARRs and FTRs hedged 97.2 percent of the congestion costs within PJM.

Table 7 ARR and FTR congestion hedging by control zone: Planning period 2007 to 2008

Control Zone	ARR Credits	FTR Credits	FTR Auction Revenue	Total ARR and FTR Hedge	Congestion	Total Hedge - Congestion Difference	Percent Hedged
AECO	$30,399,517	$33,818,154	$26,487,534	$37,730,137	$48,611,136	($10,880,999)	77.6%
AEP	$235,192,904	$74,060,394	$122,461,520	$186,791,778	$224,108,931	($37,317,153)	83.3%
AP	$585,103,411	$592,512,119	$491,764,536	$685,850,994	$462,376,328	$223,474,666	>100%
BGE	$75,854,553	$63,409,285	$63,365,238	$75,898,600	$74,161,439	$1,737,161	>100%
ComEd	$22,605,389	($64,942,926)	($30,250,928)	($12,086,609)	$215,858,584	($227,945,193)	<0%
DAY	$10,283,638	($35,353,881)	($25,729,852)	$659,609	$17,884,456	($17,224,847)	3.7%
DLCO	$1,861,518	($24,829,264)	($27,921,904)	$4,954,158	$11,410,848	($6,456,690)	43.4%
Dominion	$184,589,565	$253,021,344	$196,207,169	$241,403,740	$283,479,504	($42,075,764)	85.2%
DPL	$24,582,545	$27,834,839	$41,345,962	$11,071,422	$56,034,968	($44,963,546)	19.8%
JCPL	$44,530,720	$289,812,635	$87,916,212	$246,427,143	$228,011,843	$18,415,300	>100%
Met-Ed	$40,542,857	$56,186,522	$56,735,375	$39,994,004	$52,663,379	($12,669,375)	75.9%
PECO	$89,541,114	$42,270,945	$94,973,373	$36,838,686	($55,027,453)	$91,866,139	>100%
PENELEC	$35,825,762	$242,914,519	$139,361,603	$139,378,678	$186,535,306	($47,156,628)	74.7%
Pepco	$45,765,395	$266,025,285	$218,553,668	$93,237,012	$177,145,206	($83,908,194)	52.6%
PJM	$15,188,162	$13,724,519	$13,853,916	$15,058,765	($85,980,478)	$101,039,243	>100%
PPL	$53,816,218	$53,460,555	$57,050,864	$50,225,909	($14,546,632)	$64,772,541	>100%
PSEG	$142,818,598	$148,445,275	$206,565,360	$84,698,513	$102,416,667	($17,718,154)	82.7%
RECO	$1,951,540	$6,541,812	$3,398,262	$5,095,090	$10,333,202	($5,238,112)	49.3%
Total	$1,640,453,406	$2,038,912,131	$1,736,137,908	$1,943,227,629	$1,995,477,234	($52,249,605)	97.4%

FTR and ARR Conclusion

The annual ARR allocation and the FTR auctions provide market participants with hedging instruments. These instruments can be used for hedging positions or for speculation. The Long Term FTR Auction, 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 2008 to 2009 planning period were competitive and succeeded in providing all qualified market participants with equal access to FTRs. The MMU recommends that the rules for ARR reassignment when load shifts should address the fact that in the case of ARRs self scheduled as FTRs, the underlying FTRs do not follow the load while the ARRs do.

ARRs were 100 percent revenue adequate for both the 2007 to 2008 and the 2008 to 2009 planning periods. FTRs were paid at 100 percent of the target allocation level for the 12-month period of the 2007 to 2008 planning period, and at 99.6 percent of the target allocation level for the first seven months of the 2008 to 2009 planning period.

The total of ARR and FTR revenues hedged 97.4 percent of the congestion costs in the Day-Ahead Energy Market and the balancing energy market within PJM for the 2007 to 2008 planning period and 97.2 percent of the congestion costs in PJM in the first seven months of the 2008 to 2009 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 and 2008 as a result of participant counter flow positions in the FTR markets and inadequate participant financial resources. The magnitude of the defaults was the result of both the size of the FTR positions defaulted and of the PJM credit policies, which did not require sufficient collateral to cover the participants' losses. PJM also faced additional defaults in 2008. 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.