Q1

State of the Market Report for PJM

Monitoring Analytics, LLC

Independent
Market Monitor
for PJM

5.18.2015

2015

Preface

The PJM Market Monitoring Plan 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, and quarterly reports that update selected portions of the annual report and which may focus on certain topics of particular interest to the Market Monitoring Unit. The quarterly reports shall not be as extensive as the annual reports. In its annual, quarterly and other reports, the Market Monitoring Unit may make recommendations regarding any matter within its purview. The annual reports shall, and the quarterly reports may, 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 annual reports shall, and the quarterly reports may 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 (MMU) for PJM Interconnection, L.L.C. (PJM),[2] and is also known as the Independent Market Monitor for PJM (IMM), submits this *2015 Quarterly State of the Market Report for PJM: January through March*.[3]

1 PJM Open Access Transmission Tariff (OATT) Attachment M (PJM Market Monitoring Plan) § VI.A. Capitalized terms used herein and not otherwise defined have the meaning provided in the OATT, PJM Operating Agreement, PJM Reliability Assurance Agreement or other tariff that PJM has on file with the Federal Energy Regulatory Commission (FERC or Commission).
2 OATT Attachment M § II(f).
3 All references to this report should refer to the source as Monitoring Analytics, LLC, and should include the complete name of the report: *2015 Quarterly State of the Market Report for PJM: January through March*.

Introduction

2015 Q1 in Review

The results of the energy market, the results of the capacity market and the results of the regulation market were competitive in the first three months of 2015. The PJM markets work. The PJM markets bring customers the benefits of competition. The goal of competition is to provide customers wholesale power at the lowest possible price, but no lower. The state of the PJM markets in the first three months of 2015 reflected the winter weather in February 2015 which was unusually cold, although not as extreme as the conditions in January 2014. The stress on the markets during the winter weather was a reminder that markets must work during extreme conditions as well as more normal conditions. PJM markets did work during the extreme conditions but the experience continues to highlight areas of market design that need improvement.

The PJM market design must be robust to stress. Markets that only work under normal conditions are not effective markets. Continued success requires markets that are flexible and adaptive. However, wholesale power markets are defined by complex rules. Markets do not automatically provide competitive and efficient outcomes. Despite the complex rules, these are markets and not administrative constructs, and have all the potential efficiency benefits of markets. There are areas of market design that need further improvement in order to ensure that the PJM markets continue to adapt successfully to changing conditions. The details of market design matter.

The overall energy market results support the conclusion that energy prices in PJM are set, generally, by marginal units offering at, or close to, their marginal costs, although this was not always the case during the high demand hours in February 2015 and January 2014. This is evidence of generally competitive behavior, although the behavior of some participants during the high demand periods in 2014 and 2015 raises concerns about economic withholding. The performance of the PJM markets under high load conditions raised a number of concerns related to capacity market incentives, participant offer behavior in the energy market under tight market conditions, natural gas availability and pricing, demand response and interchange transactions. In particular, there are issues related to the ability to increase markups substantially in tight market conditions, to the uncertainties about the pricing and availability of natural gas, and to the lack of adequate incentives for unit owners to take all necessary actions to acquire fuel and generate power rather than take an outage.

The energy market in the first three months of 2015 reflected the combination of weather related demand and fuel costs in relatively high energy market prices. The load-weighted average real-time LMP was 45.2 percent lower in the first three months of 2015 than in the first three months of 2014, $50.91 per MWh versus $92.98 per MWh. But the load-weighted average LMP in the first three months of 2015 was 36.1 percent higher than in the first three months of 2013 and was higher than the load-weighted average LMP in the first three months of 2009 through 2013 and for 11 of 16 first quarters since the markets began in 1999.

Energy market prices decreased significantly from the first three months of 2014 as a combined result of lower fuel prices, lower demand and improved grid operations. If fuel costs in the first three months of 2015 had been the same as in the first three months of 2014, holding everything else constant, the real time load-weighted LMP in 2015 would have been 26.1 percent higher, $64.20 per MWh instead of the observed $50.91 per MWh, but still lower than in 2014.

The markup conduct of individual owners and units has an identifiable impact on market prices. In the Real-Time Energy Market, although the adjusted markup component of LMP decreased from $6.37 in the first three months of 2014 to $3.78 in the first three months of 2015, the markup was a larger percent of LMP (7.4 percent) in the first three months of 2015 than in the first three months of 2014 (6.8 percent). The adjusted markup contribution of coal units in the first three months of 2015 was $1.21. Although the price of natural gas was substantially lower in the first three months of 2015 than in 2014, the adjusted mark-up component of all gas-fired units in the first three months of 2015 was $2.10, an increase of $0.75 from the first three months of 2014. Although markups continued to be significant in the first three months of 2015, participant behavior was evaluated as competitive because marginal units generally make offers at, or close to, their marginal costs.

While total energy uplift charges decreased by $560.6 million or 75.0 percent in the first three months of 2015 compared to the first three months of 2014, from $747.5 million to $186.9 million, total uplift was still high compared to prior years, reflecting, among other things, inflexible gas supply arrangements.

Net revenue is a key measure of overall market performance as well as a measure of the incentive to invest in new generation to serve PJM markets. Net revenues are significantly affected by fuel prices, energy prices and capacity prices. Coal and natural gas prices and energy prices were lower in the first three months of 2015 than in the first three months of 2014. Net revenues from the energy market for all plant types were significantly affected by the lower prices.

While net revenues were uniformly lower in the first three months of 2015 than in the first three months of 2014, net revenues were higher than in the first quarter of 2013. The comparison to the first three months of 2014 reflects the very high net revenues in January 2014. In the first three months of 2015, average energy market net revenues decreased by 50 percent for a new CT, 44 percent for a new CC, 61 percent for a new CP, 72 percent for a new DS, 50 percent for a new nuclear plant, 26 percent for a new wind installation, and 13 percent for a new solar installation.

Particularly in times of stress on markets and when some flaws in markets are revealed, non-market solutions may appear attractive. Top down, integrated resource planning approaches are tempting because it is easy to think that experts know exactly the right mix and location of generation resources and the appropriate definition of resource diversity and therefore which technologies should be favored through exceptions to market rules. The provision of subsidies to favored technologies, whether solar, wind, coal or nuclear, is tempting for those who would benefit, but subsidies are a form of integrated resource planning that is not consistent with markets. Subsidies to existing units are no different in concept than subsidies to planned units and are equally inconsistent with markets. Cost of service regulation is tempting because guaranteed rates of return and fixed prices may look attractive to asset owners in uncertain markets and because cost of service regulation incorporates integrated resource planning.

But the market paradigm and the non-market paradigm are mutually exclusive. Once the decision is made that market outcomes must be fundamentally modified, it will be virtually impossible to return to markets.

Much of the reason that market outcomes are subject to legitimate criticism is that the markets have not been permitted to reveal the underlying supply and demand fundamentals in prices. Before market outcomes are rejected in favor of non-market choices, markets should be permitted to work. It is more critical than ever to get capacity market prices correct. A number of capacity market design elements have resulted in a substantial suppression of capacity market prices for multiple years.

These market design choices have substantial impacts. PJM is addressing the fundamental issues of the capacity market design in its Capacity Performance proposal, including price formation, product definition and performance incentives.

The price of energy must also reflect supply and demand fundamentals. While the rules on gas procurement and the inclusion of gas costs in energy market offers need clarification, cost-based offer caps should be increased to ensure that offer caps reflect actual marginal costs, even when those marginal costs are well in excess of $1,000 per MWh. But when cost based offers are greater than $1,000 per MWh, price based offers should not exceed cost based offers and cost based offers should not include a ten percent adder. PJM's reserve requirements should reflect dispatchers' actual need for reserves to maintain reliability and those reserve requirements should be reflected in prices and should trigger scarcity pricing when they are not met. Better energy market pricing will help reduce uplift and a broader allocation of uplift to all participants, including UTCs, will help reduce uplift to the level of noise rather than the significant friction on markets that it is today.

There has been a substantial decline in UTC activity beginning in September 2014, as a result of a FERC order setting September 8, 2014, as the effective date for any uplift charges ultimately assigned to UTCs.[1] To date, there have not been negative impacts on market outcomes as a result of the reduction in cleared UTC MW and there have been some positive impacts. The MMU will continue to evaluate the market results and to report on them.

While it is difficult to predict all the ramifications of the Court's EPSA decision, and the Supreme Court's review of that decision, on jurisdiction over demand side resources, the decision does create an opportunity to rethink the ways in which demand side resources can most effectively participate in wholesale power markets based on market principles.[2] Demand response should be on the demand side of the capacity market rather than on the supply side. Customers would avoid paying for capacity by interrupting designated load when PJM indicates that it is a critical hour. Customers would pay for actual load on the system during PJM-defined critical hours, e.g. maximum generation alerts, rather than relying on flawed measurement and verification methods. Capacity costs would be assigned to LSEs and by LSEs to customers, based on actual load on the system during these critical hours. Demand resources should be provided a fair opportunity to compete, but demand resources should no longer be provided special advantages inconsistent with competitive markets. This approach would work regardless of the final decision in the EPSA case.

The PJM markets and PJM market participants from all sectors face significant challenges, some of which were clearly revealed in January 2014 and February 2015 and some of which continue to be revealed. PJM and its market participants will need to continue to work constructively to address these challenges to ensure the continued effectiveness of PJM markets. A successful redesign of the PJM capacity market to address its identified flaws is the most critical initiative currently being considered by PJM stakeholders.

While the market performance in the first three months of 2015 was improved over the first three months of 2014, the underlying capacity market issues have not been addressed. For example, uplift remained high in large part as a result of inflexible unit parameters which were based, in many cases, on inflexible gas supply arrangements, outages were high, performance incentives remain weak, prices in the capacity market remain well below replacement costs and there is no resolution of the disconnect between the incentives facing electric generating units and the incentives facing gas pipelines which is a barrier to the construction of new pipeline capacity.

PJM Market Summary Statistics

Table 1-1 shows selected summary statistics describing PJM markets.

Table 1-1 PJM Market Summary Statistics, January through March, 2014 and 2015[3]

	Q1, 2014	Q1, 2015	Percent Change
Load	212,267 GWh	211,444 GWh	(0.4%)
Generation	220,017 GWh	213,119 GWh	(3.1%)
Net Actual Interchange	(243)GWh	5,021 GWh	2,166%
Losses	5,352 GWh	5,127 GWh	(4.2%)
Regulation Requirement*	664 MW	664 MW	0.0%
RTO Primary Reserve Requirement	2,063 MW	2,175 MW	5.4%
Total Billing	$21.07 Billion	$14.04 Billion	(33.4%)
Peak	**Jan 7, 2014 18:00**	**Feb 20, 2015 7:00**	
Peak Load	140,467 MW	143,086 MW	1.9%
Load Factor	0.70	0.68	(2.2%)
Installed Capacity	**As of 3/31/2014**	**As of 3/31/2015**	
Installed Capacity	182,894 MW	183,790 MW	0.5%

* This is an hourly average stated in effective MW.

1 See "PJM Interconnection, L.L.C.; Notice of Institution of Section 206 Proceeding and Refund Effective Date," Docket No. EL14-37-000 (September 8, 2014).

2 In a panel decision issued May 23, 2014, the U.S. Court of Appeals for the District of Columbia Circuit vacated in its entirety Order No. 745, which provided for payment of full LMP to demand-side resources. The decision calls into question the jurisdictional foundation for all demand response programs currently subject to FERC oversight, and, in particular, those in the energy and capacity markets. Electric Power Supply Association v. FERC, No. 11-1486, *petition for en banc review denied*; *see Demand Response Compensation in Organized Wholesale Energy Markets*, Order No. 745, FERC Stats. & Regs. ¶ 31,322 (2011); *order on reh'g*, Order No. 745-A, 137 FERC ¶ 61,215 (2011); *order on reh'g*, Order No. 745-B, 138 FERC 61,148 (2012).

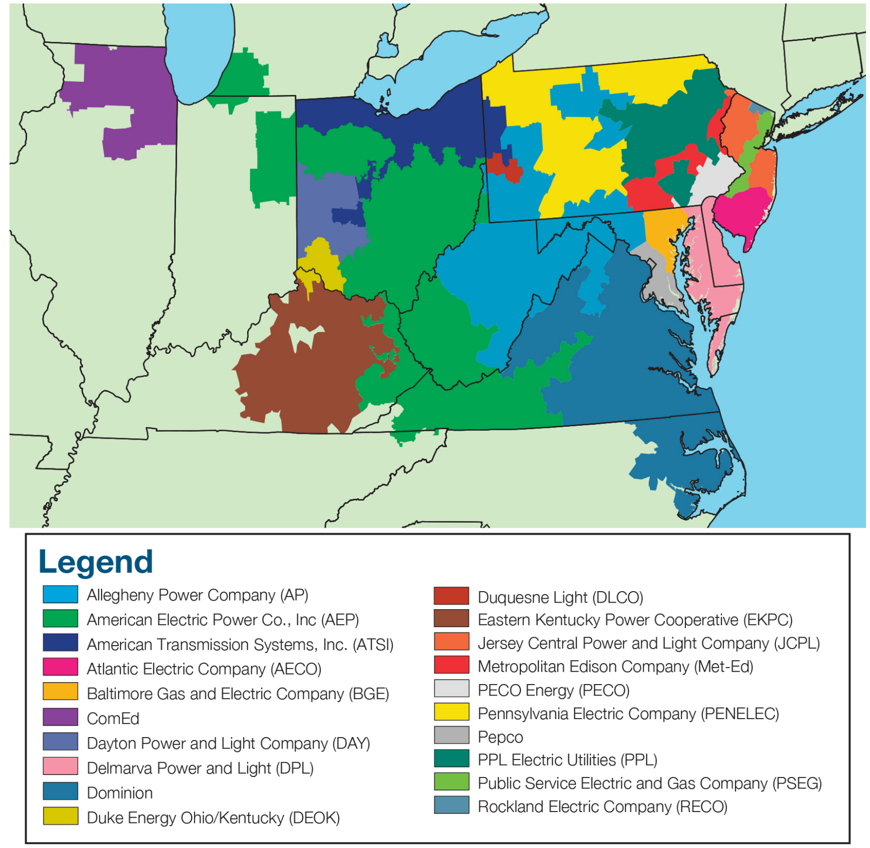
3 The load reported in this table is the accounting load plus net withdrawals at generator buses. The average hourly accounting load is reported in Section 3, "Energy Market."

PJM Market Background

The PJM Interconnection, L.L.C. (PJM) operates a centrally dispatched, competitive wholesale electric power market that, as of March 31, 2015, had installed generating capacity of 183,790 megawatts (MW) and 945 members including market buyers, sellers and traders of electricity in a region including more than 61 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 (Figure 1-1).[4,5,6]

As part of the market operator function, PJM coordinates and directs the operation of the transmission grid and plans transmission expansion improvements to maintain grid reliability in this region.

Figure 1-1 PJM's footprint and its 20 control zones

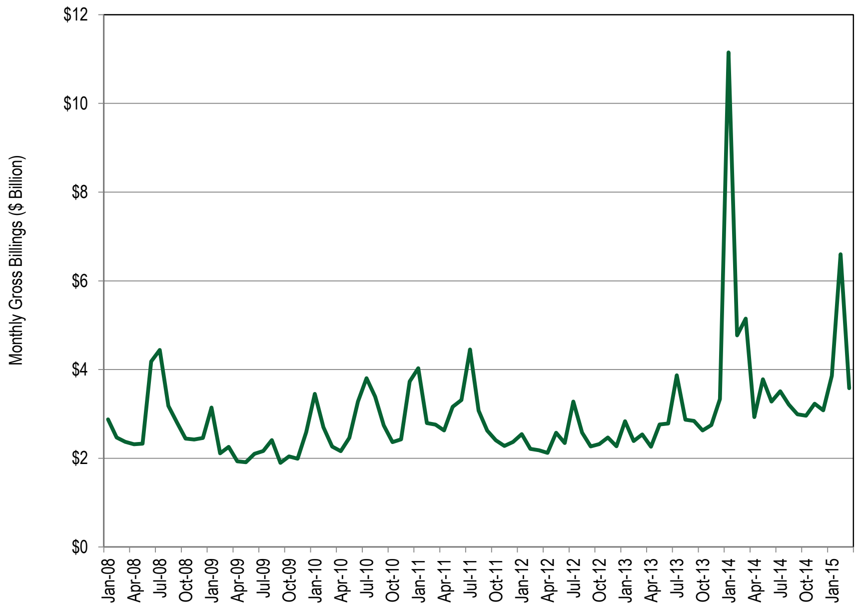


In the first three months of 2015, PJM had total billings of $14.04 billion, down 33 percent from $21.07 billion in the first three months of 2014 (Figure 1-2).[7] Despite the drop from the first quarter of 2014, the total billings in the first three months of 2015 were the second highest quarterly PJM billings, behind only the first quarter of 2014.

4 See PJM's "Member List," which can be accessed at: <http://pjm.com/about-pjm/member-services/member-list.aspx>.
5 See PJM's "Who We Are," which can be accessed at: <http://pjm.com/about-pjm/who-we-are.aspx>.
6 See the *2014 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography" for maps showing the PJM footprint and its evolution prior to 2014.

7 Monthly billing values are provided by PJM.

Figure 1-2 PJM reported monthly billings ($ Billions): 2008 through March, 2015



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 for the January through May 1999 period. 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 synchronized 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.[8,9]

Conclusions

This report assesses the competitiveness of the markets managed by PJM in the first three months of 2015, including market structure, participant behavior and market performance. This report was prepared by and represents the analysis of the Independent Market Monitor for PJM, also referred to as the Market Monitoring Unit or MMU.

For each PJM market, the market structure is evaluated as competitive or not competitive, and participant behavior is evaluated as competitive or not competitive. Most important, the outcome of each market, market performance, is evaluated as competitive or not competitive.

The MMU also evaluates the market design for each market. The market design serves as the vehicle for translating participant behavior within the market structure into market performance. This report evaluates the effectiveness of the market design of each PJM market in providing market performance consistent with competitive results.

Market structure refers to the ownership structure of the market. The three pivotal supplier (TPS) test is the most relevant measure of market structure because it accounts for both the ownership of assets and the relationship between the pattern of ownership among multiple entities and the market demand using actual market conditions with both temporal and geographic granularity. Market shares and the related Herfindahl-Hirschman Index (HHI) are also measures of market structure.

8 See also the *2014 State of the Market Report for PJM*, Volume II, Appendix B, "PJM Market Milestones."
9 Analysis of 2015 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. In June 2011, the American Transmission Systems, Inc. (ATSI) Control Zone joined PJM. In January 2012, the Duke Energy Ohio/Kentucky Control Zone joined PJM. In June 2013, the Eastern Kentucky Power Cooperative (EKPC) joined PJM. 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 prior to 2013, see *2014 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography."

Participant behavior refers to the actions of individual market participants, also sometimes referred to as participant conduct.

Market performance refers to the outcome of the market. Market performance reflects the behavior of market participants within a market structure, mediated by market design.

Market design means the rules under which the entire relevant market operates, including the software that implements the market rules. Market rules include the definition of the product, the definition of marginal cost, rules governing offer behavior, market power mitigation rules, and the definition of demand. Market design is characterized as effective, mixed or flawed. An effective market design provides incentives for competitive behavior and permits competitive outcomes. A mixed market design has significant issues that constrain the potential for competitive behavior to result in competitive market outcomes, and does not have adequate rules to mitigate market power or incent competitive behavior. A flawed market design produces inefficient outcomes which cannot be corrected by competitive behavior.

The MMU concludes for the first three months of 2015:

Table 1-2 The Energy Market results were competitive

Market Element	Evaluation	Market Design
Market Structure: Aggregate Market	Competitive	
Market Structure: Local Market	Not Competitive	
Participant Behavior	Competitive	
Market Performance	Competitive	Effective

- The aggregate market structure was evaluated as competitive because the calculations for hourly HHI (Herfindahl-Hirschman Index) indicate that by the FERC standards, the PJM Energy Market in the first three months of 2015 was moderately concentrated. Average HHI was 1087 with a minimum of 922 and a maximum of 1269 in the first three months of 2015.
- The local market structure was evaluated as not competitive due to the highly concentrated ownership of supply in local markets created by transmission constraints. The results of the three pivotal supplier (TPS) test, used to test local market structure, indicate the existence of market power in local markets created by transmission constraints. The local market performance is competitive as a result of the application of the TPS test. While transmission constraints create the potential for the exercise of local market power, PJM's application of the three pivotal supplier test mitigated local market power and forced competitive offers, correcting for structural issues created by local transmission constraints.
- Participant behavior was evaluated as competitive because the analysis of markup shows that marginal units generally make offers at, or close to, their marginal costs in both Day-Ahead and Real-Time Energy Markets, although the behavior of some participants during periods of high demand raises concerns about economic withholding.
- Market performance was evaluated as competitive because market results in the Energy Market reflect the outcome of a competitive market, as PJM prices are set, on average, by marginal units operating at, or close to, their marginal costs in both Day-Ahead and Real-Time Energy Markets, although high markups during periods of high demand did affect prices.
- Market design was evaluated as effective because the analysis shows that the PJM Energy Market resulted in competitive market outcomes. In aggregate, PJM's Energy Market design provides incentives for competitive behavior and results in competitive outcomes. In local markets, where market power is an issue, the market design mitigates market power and causes the market to provide competitive market outcomes. The role of UTCs in the Day-Ahead Energy Market continues to cause concerns. Issues related to the definition of gas costs includable in offers and the impact of the uncertainty around gas costs during high demand periods also need to be addressed.

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.[10] The approach to market power mitigation in PJM has 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.[11] There are currently no market power mitigation rules in place that limit the ability to exercise market power when aggregate market conditions are extremely tight. If market-based offer caps are raised, aggregate market power mitigation rules need to be developed.

Table 1-3 The Capacity Market results were competitive

Market Element	Evaluation	Market Design
Market Structure: Aggregate Market	Not Competitive	
Market Structure: Local Market	Not Competitive	
Participant Behavior	Competitive	
Market Performance	Competitive	Mixed

- The aggregate market structure was evaluated as not competitive. For almost all auctions held from 2007 to the present, the PJM region failed the three pivotal supplier test (TPS), which is conducted at the time of the auction.[12]
- The local market structure was evaluated as not competitive. For almost every auction held, all LDAs have failed the TPS test, which is conducted at the time of the auction.[13]
- Participant behavior was evaluated as competitive. Market power mitigation measures were applied when the Capacity Market Seller failed the market power test for the auction, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, would increase the market clearing price. Market power mitigation rules were also applied when the Capacity Market Seller submitted a sell offer for a new resource or uprate that was below the Minimum Offer Price Rule (MOPR) threshold.
- Market performance was evaluated as competitive. Although structural market power exists in the Capacity Market, a competitive outcome resulted from the application of market power mitigation rules.
- Market design was evaluated as mixed because while there are many positive features of the Reliability Pricing Model (RPM) design, there are several features of the RPM design which threaten competitive outcomes. These include the 2.5 percent reduction in demand in Base Residual Auctions, the definition of DR which permits inferior products to substitute for capacity, the replacement capacity issue, the inclusion of imports which are not substitutes for internal capacity resources and inadequate performance incentives.

Table 1-4 The Regulation Market results were competitive

Market Element	Evaluation	Market Design
Market Structure	Not Competitive	
Participant Behavior	Competitive	
Market Performance	Competitive	Flawed

- The Regulation Market structure was evaluated as not competitive for the year because the Regulation Market had one or more pivotal suppliers which failed PJM's three pivotal supplier (TPS) test in 97 percent of the hours in the first three months of 2015.
- Participant behavior in the Regulation Market was evaluated as competitive for the first three months of 2015 because market power mitigation requires competitive offers when the three pivotal supplier test is failed and there was no evidence of generation owners engaging in anti-competitive behavior.

10 PJM. OATT Attachment M (PJM Market Monitoring Plan).
11 The market performance test means that offer capping is not applied if the offer does not exceed the competitive level and therefore market power would not affect market performance.
12 In the 2008/2009 RPM Third Incremental Auction, 18 participants in the RTO market passed the TPS test.
13 In the 2012/2013 RPM Base Residual Auction, six participants included in the incremental supply of EMAAC passed the TPS test. In the 2014/2015 RPM Base Residual Auction, seven participants in the incremental supply in MAAC passed the TPS test.

- Market performance was evaluated as competitive, after the introduction of the new market design, despite significant issues with the market design.
- Market design was evaluated as flawed. While the design of the Regulation Market was significantly improved with changes introduced October 1, 2012, a number of issues remain. The market results continue to include the incorrect definition of opportunity cost. Further, the market design has failed to correctly incorporate a consistent implementation of the marginal benefit factor in optimization, pricing and settlement. In addition, the market results indicate that PJM's current marginal benefit function is, in some hours, overvaluing RegD as a substitute for RegA in the optimization.

Table 1-5 The Tier 2 Synchronized Reserve Markets results were competitive

Market Element	Evaluation	Market Design
Market Structure: Regional Markets	Not Competitive	
Participant Behavior	Competitive	
Market Performance	Competitive	Mixed

- The Synchronized Reserve Market structure was evaluated as not competitive because of high levels of supplier concentration.
- Participant behavior was evaluated as competitive because the market rules require competitive, cost based offers.
- Market performance was evaluated as competitive because the interaction of participant behavior with the market design results in competitive prices.
- Market design was evaluated as mixed. Market power mitigation rules result in competitive outcomes despite high levels of supplier concentration. However, Tier 1 reserves are inappropriately compensated when the non-synchronized reserve market clears with a non-zero price.

Table 1-6 The Day-Ahead Scheduling Reserve Market results were competitive

Market Element	Evaluation	Market Design
Market Structure	Competitive	
Participant Behavior	Mixed	
Market Performance	Competitive	Mixed

- The Day-Ahead Scheduling Reserve Market structure was evaluated as competitive because market participants did not fail the three pivotal supplier test.
- Participant behavior was evaluated as mixed because while most offers appeared consistent with marginal costs, a significant proportion of offers reflected economic withholding.
- Market performance was evaluated as competitive because there were adequate offers at reasonable levels in every hour to satisfy the requirement and the clearing price reflected those offers.
- Market design was evaluated as mixed because while the market is functioning effectively to provide DASR, the three pivotal supplier test, and cost-based offer capping when the test is failed, should be added to the market to ensure that market power cannot be exercised at times of system stress.

Table 1-7 The FTR Auction Markets results were competitive

Market Element	Evaluation	Market Design
Market Structure	Competitive	
Participant Behavior	Competitive	
Market Performance	Competitive	Mixed

- Market structure was evaluated as competitive because the FTR auction is voluntary and the ownership positions resulted from the distribution of ARRs and voluntary participation.
- Participant behavior was evaluated as competitive because there was no evidence of anti-competitive behavior.

- Market performance was evaluated as competitive because it reflected the interaction between participant demand behavior and FTR supply, limited by PJM's analysis of system feasibility.
- Market design was evaluated as mixed because while there are many positive features of the ARR/FTR design including a wide range of options for market participants to acquire FTRs and a competitive auction mechanism, there are several problematic features of the ARR/FTR design which need to be addressed. The market design incorporates widespread cross subsidies which are not consistent with an efficient market design and the market design as implemented results in overselling FTRs. FTR funding levels are reduced as a result of these factors.

Role of MMU

The FERC assigns three core functions to MMUs: reporting, monitoring and market design.[14] These functions are interrelated and overlap. The PJM Market Monitoring Plan establishes these functions, providing that the MMU is responsible for monitoring: compliance with the PJM Market Rules; actual or potential design flaws in the PJM Market Rules; structural problems in the PJM Markets that may inhibit a robust and competitive market; the actual or potential exercise of market power or violation of the market rules by a Market Participant; PJM's implementation of the PJM Market Rules or operation of the PJM Markets; and such matters as are necessary to prepare reports.[15]

Reporting

The MMU performs its reporting function primarily by issuing and filing annual and quarterly state of the market reports; regular reports on market issues; such as RPM auction reports; reports responding to requests from regulators and other authorities; and ad hoc reports on specific topics. The state of the market reports provide a comprehensive analysis of the structure, behavior and performance of PJM markets. State of the market reports and other reports are intended to inform PJM, the PJM Board, FERC, other regulators, other authorities, market participants, stakeholders and the general public about how well PJM markets achieve the competitive outcomes necessary to realize the goals of regulation through competition, and how the markets can be improved.

Monitoring

To perform its monitoring function, the MMU screens and monitors the conduct of Market Participants under the MMU's broad purview to monitor, investigate, evaluate and report on the PJM Markets.[16] The MMU has direct, confidential access to the FERC.[17] The MMU may also refer matters to the attention of state commissions.[18]

The MMU monitors market behavior for violations of FERC Market Rules.[19] The MMU will investigate and refer "Market Violations," which refers to any of "a tariff violation, violation of a Commission-approved order, rule or regulation, market manipulation, or inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies…"[20,21,22] The MMU also monitors PJM for compliance with the rules, in addition to market participants.[23]

14 18 CFR § 35.28(g)(3)(ii); see also *Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, *FERC Stats. & Regs. ¶31,281 (2008) ("Order No. 719"), order on reh'g, Order No. 719-A, FERC Stats. & Regs. ¶31,292 (2009), reh'g denied*, Order No. 719-B, 129 FERC ¶ 61,252 (2009).

15 OATT Attachment M § IV; 18 CFR § 1c.2.

16 OATT Attachment M § IV.

17 OATT Attachment M § IV.K.3.

18 OATT Attachment M § IV.H.

19 OATT Attachment M § II(d)&(q) ("FERC Market Rules" mean the market behavior rules and the prohibition against electric energy market manipulation codified by the Commission in its Rules and Regulations at 18 CFR §§ 1c.2 and 35.37, respectively; the Commission-approved PJM Market Rules and any related proscriptions or any successor rules that the Commission from time to time may issue, approve or otherwise establish… "PJM Market Rules" mean the rules, standards, procedures, and practices of the PJM Markets set forth in the PJM Tariff, the PJM Operating Agreement, the PJM Reliability Assurance Agreement, the PJM Consolidated Transmission Owners Agreement, the PJM Manuals, the PJM Regional Practices Document, the PJM-Midwest Independent Transmission System Operator Joint Operating Agreement or any other document setting forth market rules.")

20 The FERC defines manipulation as engaging "in any act, practice, or course of business that operates or would operate as a fraud or deceit upon any entity." 18 CFR § 1c.2(a)(3). Manipulation may involve behavior that is consistent with the letter of the rules, but violates their spirit. An example is market behavior that is economically meaningless, such as equal and opposite transactions, which may entitle the transacting party to a benefit associated with volume. Unlike market power or rule violations, manipulation must be intentional. The MMU must build its case, including an inference of intent, on the basis of market data.

21 OATT Attachment M § II(h-1).

22 The MMU has no prosecutorial or enforcement authority. The MMU notifies the FERC when it identifies a significant market problem or market violation. OATT Attachment M § IV.I.1. If the problem or violation involves a market participant, the MMU discusses the matter with the participant(s) involved and analyzes relevant market data. If that investigation produces sufficient credible evidence of a violation, the MMU prepares a formal referral and thereafter undertakes additional investigation of the specific matter only at the direction of FERC staff. *Id.* If the problem involves an existing or proposed law, rule or practice that exposes PJM markets to the risk that market power or market manipulation could compromise the integrity of the markets, the MMU explains the issue, as appropriate, to the FERC, state regulators, stakeholders or other authorities. The MMU may also participate as a party or provide information or testimony in regulatory or other proceedings.

23 OATT Attachment M § IV.C.

Another important component of the monitoring function is the review of inputs to mitigation. The actual or potential exercise of market power is addressed in part through *ex ante* mitigation rules incorporated in PJM's market clearing software for the energy market, the capacity market and the regulation market. If a market participant fails the TPS test in any of these markets its offer is set to the lower of its price based or cost based offer. This prevents the exercise of market power and ensures competitive pricing, provided that the cost based offer accurately reflects short run marginal cost. Cost based offers for the energy market and the regulation market are based on incremental costs as defined in the PJM Cost Development Guidelines (PJM Manual 15).[24] The MMU evaluates every offer in each capacity market (RPM) auction using data submitted to the MMU through web-based data input systems developed by the MMU.[25]

The MMU also reviews operational parameter limits included with unit offers, evaluates compliance with the requirement to offer into the energy and capacity markets, evaluates the economic basis for unit retirement requests and evaluates and compares offers in the Day-Ahead and Real-Time Energy Markets.[26,27,28,29]

The MMU reviews offers and inputs in order to evaluate whether those offers raise market power concerns.[30] Market participants, not the MMU, determine and take responsibility for offers that they submit and the market conduct that those offers represent.[31] If the MMU has a concern about an offer, the MMU may raise that concern with the FERC or other regulatory authorities. The FERC and other regulators have enforcement and regulatory authority that they may exercise with respect to offers submitted by market participants. PJM also reviews offers, but it does so in order to determine whether offers comply with the PJM tariff and manuals.[32] PJM, in its role as the market operator, may reject an offer that fails to comply with the market rules. The respective reviews performed by the MMU and PJM are separate and non-sequential.

The PJM Markets monitored by the MMU include market related procurement processes conducted by PJM, such as for Black Start resources included in the PJM system restoration plan.[33.34] With the introduction of competitive transmission development policy in Order No. 1000, a competitive procurement process for including projects in PJM Regional Transmission Expansion Plan is now in place.[35]

Market Design

In order to perform its role in PJM market design, the MMU evaluates existing and proposed PJM Market Rules and the design of the PJM Markets.[36] The MMU initiates and proposes changes to the design of such markets or the PJM Market Rules in stakeholder or regulatory proceedings.[37] In support of this function, the MMU engages in discussions with stakeholders, State Commissions, PJM Management, and the PJM Board; participates in PJM stakeholder meetings or working groups regarding market design matters; publishes proposals, reports or studies on such market design issues; and makes filings with the Commission on market design issues.[38] The MMU also recommends changes to the PJM Market Rules to the staff of the Commission's Office of Energy Market Regulation, State Commissions, and the PJM Board.[39] The MMU may provide in its annual, quarterly and other reports "recommendations regarding any matter within its purview."[40]

24 See OATT Attachment M-Appendix § II.A.
25 OATT Attachment M-Appendix § II.E.
26 OATT Attachment M-Appendix § II.B.
27 OATT Attachment M-Appendix § II.C.
28 OATT Attachment M-Appendix § IV.
29 OATT Attachment M-Appendix § VII.
30 OATT Attachment M § IV.
31 OATT § 12A.
32 OATT § 12A.
33 See OATT Attachment M-Appendix § II(p).
34 See OATT Attachment M-Appendix § III.
35 OA Schedule 6 § 1.5.
36 OATT Attachment M § IV.D.
37 *Id.*
38 *Id.*
39 *Id.*
40 OATT Attachment M § VI.A.

Recommendations

Consistent with its core function to "[e]valuate existing and proposed market rules, tariff provisions and market design elements and recommend proposed rule and tariff changes,"[41] the MMU recommends specific enhancements to existing market rules and implementation of new rules that are required for competitive results in PJM markets and for continued improvements in the functioning of PJM markets.

As of March 31, 2015, PJM has adopted or partially adopted 13 percent of all current MMU recommendations, and 10 percent of current high priority recommendations. (Table 2-1) Seventy-two percent of high priority recommendations are pending FERC or stakeholder action. The MMU recognizes that these results reflect progress on current recommendations and do not include prior recommendations that may have been adopted. The MMU is in the process of evaluating all prior and current recommendations made and will report on the results.

In this *2015 Quarterly State of the Market Report for PJM: January through March*, there are no new recommendations, and the MMU reports the following summarized recommendations.[42]

Table 1-8 Summarized list of MMU recommendations

Priority	Section	Summary Description	First Reported	Adopted/Status
Medium	3 – Energy Market	Eliminate FMU and AU adders.	2012	Adopted partially, Q4, 2014
Low	3 – Energy Market	Require that all generating units identify the fuel type associated with offered schedules.	Q2, 2014	Adopted in full, Q4, 2014.
Medium	3 – Energy Market	Apply Tariff definition of max emergency at all times, not just during max emergency events.	2012	Not adopted.
Medium	3 – Energy Market	Do not use ATSI Interface or similar interfaces to set zonal capacity prices to accommodate inadequacy of DR product.	2013	Not adopted.
Low	3 – Energy Market	Review transmission facility ratings to ensure normal, emergency, and load dump ratings in transmission system modeling are accurate.	2013	Not adopted.
Low	3 – Energy Market	Update outage impact studies, RPM reliability analyses for capacity deliverability and reliability analyses used in RTEP for transmission upgrades to be consistent with the more conservative emergency operations implemented in June 2013.	2013	Not adopted.
Low	3 – Energy Market	Clarify roles of PJM and the transmission owners in the decision making process to control for local contingencies. Strengthen PJM's role and make the process transparent.	2013	Not adopted.
Low	3 – Energy Market	Coordinate interchange optimization with neighboring regions that does not require the scheduling of physical power.	2013	Not adopted.
Low	3 – Energy Market	Explain in the appropriate manual the initial creation of hubs, the process for modifying hub definitions and a description of how hub definitions have changed.	2013	Not adopted.
Low	3 – Energy Market	Treat hours with net withdrawal at a gen bus as load for calculating load and load weighted LMP. Conversely, treat injections as generation.	2013	Not adopted.
Low	3 – Energy Market	Identify and collect data on available behind the meter generation resources, including nodal location information and relevant operating parameters.	2013	Not adopted.
Medium	3 – Energy Market	Permit generators to submit cost based offers above $1,000/MWh if consistent with Cost Development Guidelines, excluding 10% adder.	2014 Annual	Not adopted. Pending before FERC.
Medium	3 – Energy Market	Create and implement clear, explicit and detailed rules for recalling energy from PJM capacity resources, prohibiting new energy exports from PJM capacity resources, and purchasing emergency energy.	Q1, 2014	Not adopted.

41 18 CFR § 35.28(g)(3)(ii)(A); see also OATT Attachment M § IV.D.
42 For more detail on the recommendations, and their priority and adoption status, see Section 2, "Recommendations."

Priority	Section	Summary Description	First Reported	Adopted/Status
Medium	4 – Energy Uplift	Do not use closed loop interface prices to set zonal prices to accommodate inferior DR product or to accommodate reactive issues in the LMP model.	2014 Annual	Not adopted.
Medium	4 – Energy Uplift	Study closed loop interface issues to ensure the results are consistent with energy market fundamentals, and provide advanced notification to markets before implementing closed loop interfaces.	2014 Annual	Not adopted. Stakeholder process.
Medium	4 – Energy Uplift	Identify and classify all reasons for incurring operating reserves in DA and RT markets to improve transparency.	2012	Adopted partially
High	4 – Energy Uplift	Revise operating reserve confidentiality rules to improve transparency.	2013	Not adopted.
Medium	4 – Energy Uplift	Eliminate day-ahead operating reserves, and base energy uplift payments on real-time output.	2013	Not adopted. Stakeholder process.
Medium	4 – Energy Uplift	Use regulation net revenues as an offset in BOR credit calculations.	2013	Not adopted. Stakeholder process.
Low	4 – Energy Uplift	Do not compensate self-scheduled units for startup costs when scheduled to start before self-scheduled hours.	2013	Not adopted. Stakeholder process.
High	4 – Energy Uplift	Calculate Energy and Ancillary Service LOC using Energy Market schedule.	2012	Not adopted. Stakeholder process.
Medium	4 – Energy Uplift	Include no load and startup costs as avoidable in calculation of LOC paid to CTs and diesels scheduled in DA but not committed in RT.	2012	Not adopted. Stakeholder process.
Medium	4 – Energy Uplift	Calculate LOC paid to CTs and diesels scheduled in DA but not committed in RT based on segments of hours, not hourly.	2014 Annual	Not adopted.
Medium	4 – Energy Uplift	Use the entire offer curve and not a single point on the offer curve to calculate energy LOC.	2012	Not adopted. Stakeholder process.
High	4 – Energy Uplift	Require UTCs to pay operating reserves.	2013	Not adopted. Stakeholder process.
High	4 – Energy Uplift	Eliminate using IBTs in calculating deviations used to calculate BOR charges.	2013	Not adopted. Stakeholder process.
Medium	4 – Energy Uplift	Allocate energy uplift payments (other than voltage/reactive or black start) to units scheduled as must run in DA as a reliability charge to RT load, exports, and wheels.	2014 Annual	Not adopted. Stakeholder process.
Medium	4 – Energy Uplift	Reallocate operating reserve credits paid to units supporting the Con Edison -- PJM Transmission Service Agreements.	2013	Not adopted.
Medium	4 – Energy Uplift	Categorize and allocate the total cost of providing reactive support as reactive services. Calculate reactive service credits consistent with operating reserve credits.	2012	Not adopted. Stakeholder process.
Low	4 – Energy Uplift	Include RT exports and wheels in cost of providing reactive support to 500 kV system or above, which currently supports RT RTO load.	Q2, 2014	Not adopted.
High	4 – Energy Uplift	Enhance uplift rules to reflect the elimination of DA uplift, and the timing and reasons of commitment decisions.	Q1, 2014	Not adopted. Stakeholder process.
High	5 – Capacity	Enforce a consistent definition of capacity resource to be a physical resource at time of auction and in the relevant delivery year. Apply requirement to all resource types, including planned generation, demand to all resource types, including planned generation, demand resources and imports. resources and imports.	2013	Not adopted. Pending before FERC.
High	5 – Capacity	Modify definition of DR to be substitutable for other generation capacity resources. Eliminate Limited and Extended Summer DR so DR has the same obligation to provide capacity year round as generation capacity resources.	2013	Not adopted. Pending before FERC.
Medium	5 – Capacity	Terminate the 2.5 percent demand adjustment (Short Term Resource Procurement Target) and add it back to the demand curve.	2013	Not adopted. Pending before FERC.
Medium	5 – Capacity	Redefine LDA test, and include reliability analysis in redefined model.	2013	Not adopted.
Low	5 – Capacity	Require that capacity resource offers in DA market be competitive (short run marginal cost of units.)	2013	Not adopted.
Low	5 – Capacity	Clearly define operational details of protocols for recalling energy output of capacity resources in emergency conditions.	2010	Not adopted.
High	5 – Capacity	Require that all capacity have firm transmission to the PJM border acquired prior to the offering in an RPM auction.	2014	Not adopted. Pending before FERC.
High	5 – Capacity	Require that all capacity imports be pseudo tied so imports are full substitutes for internal, physical capacity resources.	2014	Not adopted. Pending before FERC.
High	5 – Capacity	Require that all resources importing capacity into PJM accept a must offer commitment.	2014	Not adopted. Pending before FERC.

Priority	Section	Summary Description	First Reported	Adopted/Status
High	5 – Capacity	Require that the net revenue calculation used by PJM to calculate the Net CONE VRR parameter reflect the actual flexibility of units in responding to price signals rather than using assumed fixed operating blocks that are not a result of actual unit limitations.	2013	Not adopted.
Low	5 – Capacity	Remove the rule that exempts from offer capping small proposed increases in the capability of a Generation Capacity Resource.	2013	Not adopted.
High	5 – Capacity	As part of the MOPR unit specific standard of review, require that all projects use the same basic modeling assumptions.	2013	Not adopted.
Medium	5 – Capacity	Change the RPM solution to explicitly incorporate the cost of make-whole payments in the objective function.	2014	Not adopted.
Medium	5 – Capacity	Change the RPM solution to define variables for the BRA optimization model directly rather than employing the current iterative approach.	2014	Not adopted.
High	5 – Capacity	Pay capacity resources on basis of whether they produce energy when called upon in critical hours.	2013	Not adopted. Pending before FERC.
Medium	5 – Capacity	Units not capable of supplying energy consistent with DA offer should reflect outage.	2013	Not adopted. Pending before FERC.
Medium	5 – Capacity	Eliminate all OMC outages from market impacting forced outage rate calculations.	2013	Not adopted. Pending before FERC.
Medium	5 – Capacity	Eliminate the exception related to lack of gas during the winter period for single-fuel, natural gas-fired units.	2013	Not adopted. Pending before FERC.
High	6 – Demand Response	Allow only one demand resources product, with an obligation to respond when called for all hours of the year.	2013	Not adopted. Pending before FERC.
High	6 – Demand Response	Emergency Load Response should be classified as an economic program and not an emergency program.	2012	Partially adopted.
High	6 – Demand Response	Apply daily must offer requirement to demand resources comparably to generation capacity resources.	2013	Not adopted. Pending before FERC.
High	6 – Demand Response	Apply $1,000 offer cap requirement to demand resources comparably to cap on energy offers of generation capacity resources.	2013	Not adopted. Pending before FERC.
Medium	6 – Demand Response	Shorten demand resource lead time to 30 minutes, with one hour minimum dispatch.	2013	Adopted in full, Q1, 2014
High	6 – Demand Response	Require demand resources to provide nodal location on grid.	2013	Not adopted.
Medium	6 – Demand Response	Measurement and verification should reflect compliance.	2012	Not adopted.
Medium	6 – Demand Response	Compliance rules should be revised to include submittal of hourly load data, and negative values when calculating compliance across hours and registrations.	2012	Not adopted.
Medium	6 – Demand Response	Adopt the ISO-NE metering requirements so dispatchers have information for reliability and so DR market payments be calculated based on interval meter data at the site of the demand reductions.	2013	Not adopted.
Medium	6 – Demand Response	DR event compliance and penalties should be calculated hourly.	2013	Not adopted. Pending before FERC.
Low	6 – Demand Response	DR load drop designated as "Other" should record the method of load drop.	2013	Adopted in full, Q2, 2014
Low	6 – Demand Response	Initiate load management testing with limited warning to CSPs.	2013	Not adopted.
High	6 – Demand Response	Customers should be able to avoid capacity and energy charges by not using capacity and energy at their discretion and, customer payments should be determined only by metered load.	2014 Annual	Not adopted. Pending before FERC.
Medium	9 – Interchange Transactions	Eliminate IMO Interface Pricing Point, assign MISO pricing point to IESO transactions.	2013	Not adopted.
Low	9 – Interchange Transactions	Monitor and adjust interface component weighting and pricing point mappings to keep interface prices consistent with system conditions and topology changes, and to account for loop flows.	2009	Adopted partially, Q2, 2014
Medium	9 – Interchange Transactions	Change RT dispatchable transaction submission deadline from 12:00 day prior to 3 hours prior to start. Change minimum duration from one hour to 15 minutes.	Q3, 2014	Not adopted.
Medium	9 – Interchange Transactions	Collaborate with adjacent regions to remove need for market partcipants to schedule physical transactions across seams. Optimize joint dispatch to treat seams as a constraint similar to constraints within an LMP market.	Q3, 2014	Not adopted.
Medium	9 – Interchange Transactions	PJM should permit unlimited spot market imports and exports at all PJM Interfaces.	2012	Not adopted.
Medium	9 – Interchange Transactions	Validate submitted transactions to prohibit disaggregation that defeats the interface pricing rule by obscuring the true source or sink.	2013	Not adopted.
Medium	9 – Interchange Transactions	Require market participants to submit transactions on market paths that reflect expected actual flow.	2013	Not adopted.
High	9 – Interchange Transactions	Implement rules to prevent sham scheduling.	2012	Not adopted. Stakeholder process.

Priority	Section	Summary Description	First Reported	Adopted/Status
Low	9 – Interchange Transactions	Eliminate NIPSCO and Southeast interface pricing points from DA and RT energy markets. With VACAR, assign SouthIMP/EXP to transactions created under reserve sharing agreement.	2013	Not adopted.
Low	9 – Interchange Transactions	Provide the required 12-month notice to DEP to unilaterally terminate the Joint Operating Agreement.	2013	Not adopted.
Medium	9 – Interchange Transactions	PJM should continue to work with MISO to improve the ways in which interface flows and prices are established.	2012	Adopted partially, Q4, 2013
Medium	9 – Interchange Transactions	Remove the incentive to engage in sham scheduling activities using the PJM/IMO interface price.	2014 Annual	Not adopted. Stakeholder process.
Medium	9 – Interchange Transactions	Cap marginal loss surplus allocations so marginal loss surplus credits cannot exceed transmissssion system fixed cost contributions.	2014 Annual	Not adopted.
High	10 – Ancillary Services	Modify Regulation market to consistently apply marginal benefit factor throughout optimization, assignment, and settlement.	2013	Not adopted.
High	10 – Ancillary Services	Eliminate rule requiring payment of tier 1 synchronized reserve resources when non-synchronized reserve price is above zero.	2013	Not adopted. Stakeholder process.
High	10 – Ancillary Services	Make no payments to tier 1 resources if they are deselected in the PJM market solution.	Q3, 2014	Adopted in full, Q3, 2014
Medium	10 – Ancillary Services	Enforce tier 2 synchronized reserve must offer provision of scarcity pricing.	2013	Adopted partially
Low	10 – Ancillary Services	Define why tier 1 biasing is used in optimized solution to Tier 2 Synchronized Reserve Market. Identify rule applied to each instance of biasing.	2013	Not adopted.
Low	10 – Ancillary Services	Investigate secondary reserve performance during recent scarcity events and replace DASR with a real time dispatchable reserve product.	2013	Not adopted.
Low	10 – Ancillary Services	Revise the current black start confidentiality rules in order to allow a more transparent disclosure of information.	2013	Not adopted.
Low	10 – Ancillary Services	Incorporate the three pivotal supplier test in the DASR Market.	2012	Not adopted.
Low	12 – Planning	Create mechanism to permit a direct comparison, or competition, between transmission and generation alternatives.	2013	Not adopted.
Low	12 – Planning	Implement rules to permit competition to provide financing of transmission projects.	2013	Not adopted.
Low	12 – Planning	Address question of whether CIRs should persist after unit retirement to prevent incumbents from exploiting CIRs to block competitive entry.	2013	Not adopted.
Low	12 – Planning	Outsource interconnection studies to an independent party, rather than relying on incumbent transmission owners.	2013	Not adopted.
Medium	12 – Planning	Projects should be removed from the queue, if they are no longer viable and no longer planning to complete the project.	2013	Not adopted.
Medium	12 – Planning	Streamline the transmission planning study phase.	Q1, 2014	Not adopted.
Medium	12 – Planning	Esablish terms of access to rights of way and property to encourage competition between incumbents and competitor transmission providers.	2014 Annual	Partially adopted.
Low	12 – Planning	Impose stricter rules about rescheduling outages, and re-evaluate the on-time status of transmission outage tickets.	2014 Annual	Not adopted.
Low	13 – FTRs and ARRs	Report correct monthly payout ratios to reduce overstatement of underfunding problem on a monthly basis.	2013	Not adopted. Stakeholder process.
High	13 – FTRs and ARRs	Eliminate portfolio netting to eliminate cross subsidies across FTR marketplace participants	2013	Not adopted. Stakeholder process.
High	13 – FTRs and ARRs	Eliminate subsidies to counter flow FTR holders by treating them comparably to prevailing flow FTR holders when the payout ratio is applied	2013	Not adopted. Stakeholder process.
High	13 – FTRs and ARRs	Eliminate cross geographic subsidies.	2013	Not adopted. Stakeholder process.
Low	13 – FTRs and ARRs	Improve transmission outage modeling in the FTR auction models.	2013	Adopted partially, 2014/2015 planning period
High	13 – FTRs and ARRs	Reduce FTR sales on paths with persistent underfunding including clear rules for what defines persistent underfunding and how the reduction will be applied.	2013	Adopted partially, 2014/2015 planning period
Medium	13 – FTRs and ARRs	Implement a seasonal ARR and FTR allocation system to better represent outages.	2013	Not adopted.
High	13 – FTRs and ARRs	Eliminate over allocation requirement of ARRs in the Annual ARR Allocation process.	2013	Not adopted. Stakeholder process.
High	13 – FTRs and ARRs	Apply the FTR forfeiture rule to up to congestion transactions consistent with the application of the FTR forfeiture rule to increment offers and decrement bids.	2013	Not adopted. Pending before FERC.
Medium	13 – FTRs and ARRs	Do not use ATSI Interface or similar interfaces to set zonal capacity prices to accommodate inadequacy of DR product. Study the implementation of closed loop interface constraints so as to include them in the FTR Auction model to minimize their impact on FTR funding.	2013	Not adopted.

Total Price of Wholesale Power

The total price of wholesale power is the total price per MWh of purchasing wholesale electricity from PJM markets. The total price is an average price and actual prices vary by location. The total price includes the price of energy, capacity, ancillary services, and transmission service, administrative fees, regulatory support fees and uplift charges billed through PJM systems. Table 1-9 provides the average price and total revenues paid, by component, for the first three months of 2014 and the first three months of 2015.

Table 1-9 shows that Energy, Capacity and Transmission Service Charges are the three largest components of the total price per MWh of wholesale power, comprising 95.4 percent of the total price per MWh in the first three months of 2015.

Each of the components is defined in PJM's Open Access Transmission Tariff (OATT) and PJM Operating Agreement and each is collected through PJM's billing system.

Components of Total Price

- The Energy component is the real time load weighted average PJM locational marginal price (LMP).
- The Capacity component is the average price per MWh of Reliability Pricing Model (RPM) payments.
- The Transmission Service Charges component is the average price per MWh of network integration charges, and firm and non firm point to point transmission service.[43]
- The Energy Uplift (Operating Reserves) component is the average price per MWh of day-ahead, balancing and synchronous condensing charges.[44]
- The Reactive component is the average cost per MWh of reactive supply and voltage control from generation and other sources.[45]
- The Regulation component is the average cost per MWh of regulation procured through the Regulation Market.[46]
- The PJM Administrative Fees component is the average cost per MWh of PJM's monthly expenses for a number of administrative services, including Advanced Control Center (AC^2) and OATT Schedule 9 funding of FERC, OPSI and the MMU.
- The Transmission Enhancement Cost Recovery component is the average cost per MWh of PJM billed (and not otherwise collected through utility rates) costs for transmission upgrades and projects, including annual recovery for the TrAIL and PATH projects.[47]
- The Capacity (FRR) component is the average cost per MWh under the Fixed Resource Requirement (FRR) Alternative for an eligible LSE to satisfy its Unforced Capacity obligation.[48]
- The Emergency Load Response component is the average cost per MWh of the PJM Emergency Load Response Program.[49]
- The Day-Ahead Scheduling Reserve component is the average cost per MWh of Day-Ahead scheduling reserves procured through the Day-Ahead Scheduling Reserve Market.[50]
- The Transmission Owner (Schedule 1A) component is the average cost per MWh of transmission owner scheduling, system control and dispatch services charged to transmission customers.[51]
- The Synchronized Reserve component is the average cost per MWh of synchronized reserve procured through the Synchronized Reserve Market.[52]
- The Black Start component is the average cost per MWh of black start service.[53]

43 OATT §§ 13.7, 14.5, 27A & 34.
44 OA Schedules 1 §§ 3.2.3 & 3.3.3.
45 OATT Schedule 2 and OA Schedule 1 § 3.2.3B. The line item in Table 1-8 includes all reactive services charges.
46 OA Schedules 1 §§ 3.2.2, 3.2.2A, 3.3.2, & 3.3.2A; OATT Schedule 3.
47 OATT Schedule 12.
48 Reliability Assurance Agreement Schedule 8.1.
49 OATT PJM Emergency Load Response Program.
50 OA Schedules 1 §§ 3.2.3A.01 & OATT Schedule 6.
51 OATT Schedule 1A.
52 OA Schedule 1 § 3.2.3A.01; PJM OATT Schedule 6.
53 OATT Schedule 6A. The line item in Table 1-8 includes all Energy Uplift (Operating Reserves) charges for Black Start.

- The RTO Startup and Expansion component is the average cost per MWh of charges to recover AEP, ComEd and DAY's integration expenses.[54]
- The NERC/RFC component is the average cost per MWh of NERC and RFC charges, plus any reconciliation charges.[55]
- The Economic Load Response component is the average cost per MWh of day ahead and real time economic load response program charges to LSEs.[56]
- The Transmission Facility Charges component is the average cost per MWh of Ramapo Phase Angle Regulators charges allocated to PJM Mid-Atlantic transmission owners.[57]
- The Non-Synchronized Reserve component is the average cost per MWh of non-synchronized reserve procured through the Non-Synchronized Reserve Market.[58]
- The Emergency Energy component is the average cost per MWh of emergency energy.[59]

Table 1-9 Total price per MWh by category: January through March, 2014 and 2015

Category	Q1 2014 $/MWh	Q1 2015 $/MWh	Jan 2015 $/MWh	Feb 2015 $/MWh	Mar 2015 $/MWh	Q1 2014 to Q1 2015 Percent Change Totals	Q1 2014 Percent of Total	Q1 2015 Percent of Total
Load Weighted Energy	$92.98	$50.91	$38.42	$72.16	$42.02	(45.2%)	82.6%	74.0%
Capacity	$7.77	$8.48	$8.32	$7.83	$9.36	9.2%	6.9%	12.3%
Transmission Service Charges	$5.19	$6.28	$6.15	$5.82	$6.91	21.0%	4.6%	9.1%
Energy Uplift (Operating Reserves)	$3.55	$0.82	$0.56	$1.43	$0.48	(76.7%)	3.1%	1.2%
PJM Administrative Fees	$0.43	$0.44	$0.44	$0.44	$0.45	3.4%	0.4%	0.6%
Transmission Enhancement Cost Recovery	$0.36	$0.42	$0.40	$0.42	$0.45	18.9%	0.3%	0.6%
Reactive	$0.37	$0.36	$0.34	$0.36	$0.38	(1.7%)	0.3%	0.5%
Regulation	$0.63	$0.32	$0.18	$0.45	$0.33	(49.7%)	0.6%	0.5%
Capacity (FRR)	$0.06	$0.27	$0.27	$0.25	$0.30	351.2%	0.1%	0.4%
Synchronized Reserves	$0.56	$0.20	$0.12	$0.30	$0.19	(64.4%)	0.5%	0.3%
Transmission Owner (Schedule 1A)	$0.09	$0.09	$0.09	$0.09	$0.09	4.6%	0.1%	0.1%
Black Start	$0.06	$0.07	$0.07	$0.06	$0.08	21.7%	0.1%	0.1%
Day Ahead Scheduling Reserve (DASR)	$0.17	$0.03	$0.00	$0.09	$0.01	(79.4%)	0.1%	0.1%
NERC/RFC	$0.02	$0.03	$0.03	$0.03	$0.03	19.3%	0.0%	0.0%
Non-Synchronized Reserves	$0.04	$0.03	$0.02	$0.04	$0.02	(42.0%)	0.0%	0.0%
Load Response	$0.04	$0.01	$0.01	$0.01	$0.02	(64.0%)	0.0%	0.0%
RTO Startup and Expansion	$0.01	$0.01	$0.01	$0.01	$0.01	(15.9%)	0.0%	0.0%
Transmission Facility Charges	$0.00	$0.00	$0.00	$0.00	$0.00	0.0%	0.0%	0.0%
Emergency Energy	$0.13	$0.00	$0.00	$0.00	$0.00	(100.0%)	0.1%	0.0%
Emergency Load Response	$0.18	$0.00	$0.00	$0.00	$0.00	(100.0%)	0.2%	0.0%
Total	$112.62	$68.78	$55.41	$89.79	$61.14	(38.9%)	100.0%	100.0%

54 OATT Attachments H-13, H-14 and H-15 and Schedule 13.
55 OATT Schedule 10-NERC and OATT Schedule 10-RFC.
56 OA Schedule 1 § 3.6.
57 OA Schedule 1 § 5.3b.
58 OA Schedule 1 § 3.2.3A.001.
59 OA Schedule 1 §3.2.6.

Section Overviews

Overview: Section 3, "Energy Market"

Market Structure

- **Supply.** Supply includes physical generation and imports and virtual transactions. Average offered real-time generation decreased by 11,597 MW, or 6.6 percent, in the first three months of 2015 from an average maximum of 175,602 MW to 164,005 MW in the first three months of 2014. This decrease was a result of unit retirements between April 1, 2014, and March 31, 2015 and unit outages. In the first three months of 2015, 4.0 MW of new capacity were added to PJM. This new generation was offset by the deactivation of 7 units (241.0 MW) since January 1, 2015.

  PJM average real-time generation in the first three months of 2015 decreased by 2.9 percent from the first three months of 2014, from 100,655 MW to 97,741 MW.

  PJM average day-ahead supply in the first three months of 2015, including INCs and up-to congestion transactions, decreased by 26.7 percent from the first three months of 2014, from 168,373 MW to 123,424 MW.

- **Market Concentration.** 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.

- **Generation Fuel Mix.** During the first three months of 2015, coal units provided 43.5 percent, nuclear units 34.3 percent and gas units 25.3 percent of total generation. Compared to the first three months of 2014, generation from coal units decreased 13.8 percent, generation from gas units increased 25.3 percent and generation from nuclear units increased 1.1 percent.

- **Marginal Resources.** In the PJM Real-Time Energy Market, in the first three months of 2015, coal units were 57.21 percent of marginal resources and natural gas units were 33.10 percent of marginal resources. In the first three months of 2014, coal units were 46.59 percent and natural gas units were 42.61 percent of the marginal resources.

  In the PJM Day-Ahead Energy Market in the first three months of 2015, up-to congestion transactions were 72.8 percent of marginal resources, INCs were 5.7 percent of marginal resources, DECs were 8.5 percent of marginal resources, and generation resources were 12.3 percent of marginal resources in the first three months of 2015.

- **Demand.** Demand includes physical load and exports and virtual transactions. The PJM system peak load during the first three months of 2015 was 143,086 MW in the HE 0800 on February 20, 2015, which was 2,619 MW, or 1.9 percent, higher than the PJM peak load for the first three months of 2014, which was 140,467 MW in the HE 1900 on January 7, 2014.

- PJM average real-time load in the first three months of 2015, increased by 0.9 percent from the first three months of 2014, from 88,332 MW to 89,099 MW.PJM average day-ahead demand in the first three months of 2015, including DECs and up-to congestion transactions, decreased by 27.0 percent from the first three months of 2014, from 163,031 MW to 119,078 MW.

- **Supply and Demand: Load and Spot Market.** Companies that serve load in PJM can do so using a combination of self-supply, bilateral market purchases and spot market purchases. For the first three months of 2015, 12.8 percent of real-time load was supplied by bilateral contracts, 24.0 percent by spot market purchases and 63.2 percent by self-supply. Compared with the first three months of 2014, reliance on bilateral contracts increased by 2.2 percent, reliance on spot market purchases decreased by 2.7 percentage points and reliance on self-supply increased by 0.4 percentage points.

- **Supply and Demand: Scarcity.** There were no shortage pricing events in the first three months of 2015.

Market Behavior

- **Offer Capping for Local Market Power.** PJM offer caps units 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, for units committed to provide energy for local constraint relief, offer-capped unit hours remained at 0.3 percent in the first three months of 2014 and 2015. In the Real-Time Energy Market, for units committed to provide energy for local constraint relief, offer-capped unit hours decreased from 1.1 percent in the first three months of 2014 to 0.6 percent in the first three months of 2015.

  In the first three months of 2015, 14 control zones experienced congestion resulting from one or more constraints binding for 25 or more hours. The analysis of the application of the TPS test to local markets demonstrates that it is working successfully to offer cap pivotal owners when the market structure is noncompetitive and to ensure that owners are not subject to offer capping when the market structure is competitive.

- **Offer Capping for Reliability.** PJM also offer caps units that are committed for reliability reasons, specifically for black start service and reactive service. In the Day-Ahead Energy Market, for units committed for reliability reasons, offer-capped unit hours decreased from 0.5 percent in the first three months of 2014 to 0.2 percent in the first three months of 2015. In the Real-Time Energy Market, for units committed for reliability reasons, offer-capped unit hours decreased from 0.4 percent in the first three months of 2014 to 0.2 percent in the first three months of 2015.

- **Markup Index.** The markup index is a summary measure of participant offer behavior for individual marginal units. In the PJM Real-Time Energy Market in the first three months of 2015, 79.0 percent of marginal units had average dollar markups less than zero and had an average markup index less than or equal to 0.0. In the first three months of 2015, 8.6 percent of units had average dollar markups greater than or equal to $150. In the first three month of 2014, 14.3 percent of units had average dollar markups greater than or equal to $150.

  In the PJM Day-Ahead Energy Market in the first three months of 2015, 88.5 percent of marginal units had an average markup index less than or equal to 0.0. In the first three months of 2015, 3.8 percent of units had average dollar markups greater than or equal to $150. In the first three months of 2014, 7.0 percent of units had average dollar markups greater than or equal to $150.

- **Frequently Mitigated Units (FMU) and Associated Units (AU).** Of the 24 units eligible for FMU or AU status in at least one month during the first three months of 2015, 2 units (8.3 percent) were FMUs or AUs for all months, and 17 units (70.8 percent) qualified in only one month. A new FMU rule became effective November 1, 2014, limiting the availability of FMU adders to units with net revenues less than unit going forward costs.

- **Virtual Offers and Bids.** Any market participant in the PJM Day-Ahead Energy Market can use increment offers, decrement bids, up-to congestion transactions, import transactions and export transactions as financial instruments that do not require physical generation or load. The reduction in up-to congestion transactions (UTC) continued, following a FERC order setting September 8, 2014, as the effective date for any uplift charges subsequently assigned to UTCs.[60]

- **Generator Offers.** Generator offers are categorized as dispatchable and self scheduled. Units which are available for economic dispatch are dispatchable. Units which are self scheduled to generate fixed output are categorized as self scheduled must run. Units which are self scheduled at their economic minimum and are available for economic dispatch up to their economic maximum are categorized as self scheduled and dispatchable. Of all generator offers in the first three months of 2015, 52.7 percent were offered as available for economic dispatch, 21.9 percent were offered as self scheduled, and 21.1 percent were offered as self scheduled and dispatchable.

60 See "PJM Interconnection, L.L.C.; Notice of Institution of Section 206 Proceeding and Refund Effective Date," Docket No. EL14-37-000 (September 8, 2014).

Market Performance

- **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. Among other things, overall average prices reflect the changes in supply and demand, generation fuel mix, the cost of fuel, emission related expenses and local price differences caused by congestion. PJM Real-Time Market prices in the first three months of 2015 were between $250 and $300 for one hour.

  PJM Real-Time Energy Market prices decreased in the first three months of 2015 compared to the first three months of 2014. The load-weighted average real-time LMP was 45.2 percent lower in the first three months of 2015 than in the first three months of 2014, $50.91 per MWh versus $92.98 per MWh.

  PJM Day-Ahead Energy Market prices decreased in the first three months of 2015 compared to the first three months of 2014. The load-weighted average day-ahead LMP was 45.2 percent higher in the first three months of 2015 than in the first three months of 2014, $52.02 per MWh versus $94.97 per MWh.[61]

- **Components of LMP.** In the PJM Real-Time Energy Market, for the first three months of 2015, 36.0 percent of the load-weighted LMP was the result of coal costs, 32.5 percent was the result of gas costs and 0.65 percent was the result of the cost of emission allowances.

  In the PJM Day-Ahead Energy Market for the first three months of 2015, 27.0 percent of the load-weighted LMP was the result of the cost of coal, 17.6 percent was the result of the cost of gas, 2.7 percent was the result of the up-to congestion transactions, 20.0 percent was the result of DECs and 15.8 percent was the result of INCs.

- **Markup.** The markup conduct of individual owners and units has an identifiable impact on market prices. The markup analysis is a key indicator of the competitiveness of the Energy Market.

  In the PJM Real-Time Energy Market in the first three months of 2015, the adjusted markup component of LMP was $3.78 per MWh or 7.4 percent of the PJM real-time, load-weighted average LMP. The month of February had the highest adjusted markup component, $6.44 per MWh, or 12.65 percent of the real-time load-weighted average LMP. In the first three months of 2014, the adjusted markup was $6.36 per MWh or 6.8 percent of the PJM real-time load-weighted average LMP.

  In the PJM Day-Ahead Energy Market, marginal INCs, DECs and UTCs have zero markups. In the first three months of 2015, the adjusted markup component of LMP resulting from generation resources was $1.14 per MWh or 2.2 percent of the PJM day-ahead load-weighted average LMP.

  Participant behavior was evaluated as competitive because the analysis of markup shows that marginal units generally make offers at, or close to, their marginal costs in both Day-Ahead and Real-Time Energy Markets, although the behavior of some participants during the high demand periods in the first quarter raises concerns about economic withholding.

- **Price Convergence.** Hourly and daily price differences between the Day-Ahead and Real-Time Energy Markets fluctuate continuously and substantially from positive to negative. The difference between the average day-ahead and real-time prices was -$2.48 per MWh in the first three months of 2014 and -$4.81 per MWh in the first three months of 2015. The difference between average day-ahead and real-time prices, by itself, is not a measure of the competitiveness or effectiveness of the Day-Ahead Energy Market.

Scarcity

- There were no shortage pricing events in the first three months of 2015.
- Natural gas pipeline constraints, critical notices, and ratable take requirements for generators continued to be an issue in the first three months of 2015.

61 Tables reporting zonal and jurisdictional load and prices are in the *2014 State of the Market Report for PJM*, Volume II, Appendix C, "Energy Market."

Section 3 Recommendations

- The MMU has recommended the elimination of FMU and AU adders. Since the implementation of FMU adders, PJM has undertaken major redesigns of its market rules that affect revenue adequacy, including implementation of the RPM capacity market construct in 2007, and changes to the scarcity pricing rules in 2012. The reasons that FMU and AU adders were implemented no longer exist. FMU and AU adders no longer serve the purpose for which they were created and interfere with the efficient operation of PJM markets. (Priority: Medium. First reported 2012. Status: Adopted partially, Q4, 2014.)

  The MMU and PJM proposed, and on October 31, 2014, the Commission approved, a compromise that limited FMU adders to units with net revenues less than unit going forward costs or ACR.[62]

- The MMU recommends that PJM require all generating units to identify the fuel type associated with each of their offered schedules. (Priority: Low. First reported Q2, 2014. Status: Adopted in full, Q4, 2014.)
- The MMU recommends that the definition of maximum emergency status in the tariff apply at all times rather than just during maximum emergency events.[63] (Priority: Medium. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM not use the ATSI closed loop interface or create similar interfaces to set zonal prices to accommodate the inadequacies of the demand side resource capacity product. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM routinely review all transmission facility ratings and any changes to those ratings to ensure that the normal, emergency and load dump ratings used in modeling the transmission system are accurate and reflect standard ratings practice. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM update the outage impact studies, the reliability analyses used in RPM for capacity deliverability and the reliability analyses used in RTEP for transmission upgrades to be consistent with the more conservative emergency operations (post contingency load dump limit exceedance analysis) in the energy market that were implemented in June 2013. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that the roles of PJM and the transmission owners in the decision making process to control for local contingencies be clarified, that PJM's role be strengthened and that the process be made transparent. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM explore an interchange optimization solution with its neighboring balancing authorities that removes the need for market participants to schedule transactions. (Priority: Low. First reported 2013. Status: Not adopted.)
- There is currently no PJM documentation in the tariff or manuals explaining how hubs are created and how their definitions are changed.[64] The MMU recommends that PJM include in the appropriate manual an explanation of the initial creation of hubs, the process for modifying hub definitions and a description of how hub definitions have changed.[65] (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that during hours when a generation bus shows a net withdrawal, the energy withdrawal be treated as load, not negative generation, for purposes of calculating load and load-weighted LMP. The MMU also recommends that during hours when a load bus shows a net injection, the energy injection be treated as generation, not negative load, for purposes of calculating generation and load-weighted LMP. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM identify and collect data on available behind the meter generation resources, including nodal location information and relevant operating parameters. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that generation owners be permitted to submit cost-based offers above the $1,000/MWh energy offer cap if they are

62 149 FERC ¶ 61,091 (2014).
63 PJM. OATT Section: 6A.1.3 Maximum Emergency, (February 25, 2014), p. 1740, 1795.
64 The general definition of a hub can be found in PJM. "Manual 35: Definitions and Acronyms," Revision 23 (April 11, 2014).
65 According to minutes from the first meeting of the Energy Market Committee (EMC) on January 28, 1998, the EMC unanimously agreed to be responsible for approving additions, deletions and changes to the hub definitions to be published and modeled by PJM. Since the EMC has become the Market Implementation Committee (MIC), the MIC now appears to be responsible for such changes.

calculated in accordance with PJM's Cost Development Guidelines excluding the ten percent adder, subject to after the fact review by the MMU. Such offers should be allowed to set LMP. (Priority: Medium. First reported 2014. Status: Not adopted. Pending before FERC.)

- The MMU recommends that PJM create and implement clear, explicit and detailed rules that define the conditions under which PJM will and will not recall energy from PJM capacity resources and prohibit new energy exports from PJM capacity resources. The MMU recommends that those rules define the conditions under which PJM will purchase emergency energy while at the same time not recalling energy exports from PJM capacity resources. (Priority: Medium. First reported Q1, 2010. Status: Not adopted.)

Section 3 Conclusion

The MMU analyzed key elements of PJM energy market structure, participant conduct and market performance in the first three months of 2015, including aggregate supply and demand, concentration ratios, three pivotal supplier test results, offer capping, participation in demand response programs, loads and prices.

Average real-time offered generation decreased by 4,715 MW in the summer of 2014 compared to the summer of 2013, while peak load decreased by 15,835 MW, modifying the general supply demand balance with a corresponding impact on energy market prices. Market concentration levels remained moderate. 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 in each hour. The pattern of prices within days and across months and years illustrates how prices are directly related to supply and demand conditions and thus also illustrates the potential significance of the impact of the price elasticity of demand on prices. Energy market results in 2014 generally reflected supply-demand fundamentals, although the behavior of some participants during the high demand periods in January raises concerns about economic withholding. These issues relate to the ability to increase markups substantially in tight market conditions, to the uncertainties about the pricing and availability of natural gas, and to the lack of adequate incentives for unit owners to take all necessary actions to acquire fuel and operate rather than take an outage.

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.[66] 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 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.

PJM also offer caps units that are committed for reliability reasons in addition to units committed to provide constraint relief. Specifically, units that are committed to provide reactive support and black start service are offer capped in the energy market. These units are committed manually in both the Day-

66 The MMU reviews PJM's application of the TPS test and brings issues to the attention of PJM.

Ahead and Real-Time Energy Markets. Before 2011, these units were generally economic in the energy market. Since 2011, the percentage of hours when these units were not economic in the Real-Time Energy Market has steadily increased. In the Day-Ahead Energy Market, PJM started to commit these units as offer capped in September 2012, as part of a broader effort to maintain consistency between Real-Time and Day-Ahead Energy Markets.

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 can serve two functions in wholesale power markets: revenue adequacy and price signals. Scarcity pricing for revenue adequacy is not required in PJM. Scarcity pricing for price signals that reflect market conditions during periods of scarcity is required in PJM. 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 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. The PJM Capacity Market is explicitly designed to provide revenue adequacy and the resultant reliability. Nonetheless, with a market design that includes a direct and explicit scarcity pricing revenue true up mechanism, 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. PJM implemented scarcity pricing rules in 2012. There are significant issues with the scarcity pricing net revenue true up mechanism in the PJM scarcity pricing design, which will create issues when scarcity pricing occurs.

The overall energy market results support the conclusion that energy prices in PJM are set, generally, by marginal units operating at, or close to, their marginal costs, although this was not always the case during the high demand hours in the first quarter. This is evidence of generally competitive behavior and competitive market outcomes, although the behavior of some participants during the high demand periods in the first quarter raises concerns about economic withholding. Given the structure of the energy market, the tighter markets and the change in some participants' behavior are sources of concern in the energy market. The MMU concludes that the PJM energy market results were competitive in the first three months of 2015.

Overview: Section 4, "Energy Uplift"

Energy Uplift Results

- **Energy Uplift Charges.** Total energy uplift charges decreased by $560.6 million or 75.0 percent in the first three months of 2015 compared to the first three months of 2014, from $747.5 million to $186.9 million.
- **Energy Uplift Charges Categories.** The decrease of $560.6 million in the first three months of 2015 is comprised of a $4.3 million increase in day-ahead operating reserve charges, a $560.7 million decrease in balancing operating reserve charges, a $1.2 million decrease in reactive services charges, a $0.1 million decrease in synchronous condensing charges and a $2.9 million decrease in black start services charges.
- **Operating Reserve Rates.** The day-ahead operating reserve rate averaged $0.246 per MWh. The balancing operating reserve reliability rates averaged $0.091, $0.018 and $0.004 per MWh for the RTO, Eastern and Western regions. The balancing operating reserve deviation rates averaged $1.416, $0.113 and $0.065 per MWh for the RTO, Eastern and Western regions. The lost opportunity cost rate averaged $1.381 per MWh and the canceled resources rate averaged $0.0004 per MWh.
- **Reactive Services Rates.** The ATSI, Dominion and PENELEC control zones had the three highest reactive local voltage support rates: $0.116, $0.091 and $0.036 per MWh. The reactive transfer interface support rate averaged $0.006 per MWh.
- **Energy Uplift Costs.** In the Eastern Region, a decrement bid paid an average of $2.794 per MWh, real-time load paid an average of $0.100 per MWh and deviations either from generators, load or interchange paid an average of $2.554 per MWh. In the Western Region, a decrement bid paid an average of $2.754 per MWh, real-time load paid an average of $0.087

per MWh and deviations either from generators, load or interchange paid an average of $2.514 per MWh.

Characteristics of Credits

- **Types of units.** Combined cycles received 39.5 percent of all day-ahead generator credits and 46.3 percent of all balancing generator credits. Combustion turbines and diesels received 89.5 percent of the lost opportunity cost credits. Coal units received 75.0 percent of all reactive services credits.
- **Concentration of Energy Uplift Credits.** The top 10 units receiving energy uplift credits received 38.0 percent of all credits. The top 10 organizations received 85.9 percent of all credits. Concentration indexes for energy uplift categories classify them as highly concentrated. Day-ahead operating reserves HHI was 4177, balancing operating reserves HHI was 4318, lost opportunity cost HHI was 3487 and reactive services HHI was 8323.
- **Economic and Noneconomic Generation.** In the first three months of 2015, 88.4 percent of the day-ahead generation eligible for operating reserve credits was economic and 74.0 percent of the real-time generation eligible for operating reserve credits was economic.
- **Day-Ahead Unit Commitment for Reliability.** In the first three months of 2015, 3.1 percent of the total day-ahead generation was scheduled as must run by PJM, of which 39.9 percent received energy uplift payments.

Geography of Charges and Credits

- In the first three months of 2015, 87.2 percent of all charges allocated regionally (day-ahead operating reserves and balancing operating reserves) were paid by transactions at control zones or buses within a control zone, demand and generation, 2.6 percent by transactions at hubs and aggregates and 10.0 percent by transactions at interfaces.

Energy Uplift Issues

- **Lost Opportunity Cost Credits.** In the first three months of 2015, lost opportunity cost credits decreased by $54.7 million compared to the first three months of 2014. In the first three months of 2015, resources in the top three control zones receiving lost opportunity cost credits, AEP, Dominion and PENELEC accounted for 53.4 percent of all lost opportunity cost credits, 54.3 percent of all day-ahead generation from pool-scheduled combustion turbines and diesels, 55.6 percent of all day-ahead generation not committed in real time by PJM from those unit types and 60.1 percent of all day-ahead generation not committed in real time by PJM and receiving lost opportunity cost credits from those unit types.
- **Black Start Service Units.** Certain units located in the AEP Control Zone are relied on for their black start capability on a regular basis during periods when the units are not economic. These black start units provide black start service under the ALR option, which means that the units must be running in order to provide black start services even if the units are not economic. In the first three months of 2015, the cost of the noneconomic operation of ALR units in the AEP Control Zone was $4.7 million, a decrease of $2.9 million compared to the first three months of 2014.
- **Con Edison – PJM Transmission Service Agreements Support.** Certain units located near the boundary between New Jersey and New York City have been operated to support the transmission service agreements between Con Ed and PJM, formerly known as the Con Ed – PSEG Wheeling Contracts. These units are often run out of merit and received substantial operating reserves credits.

Energy Uplift Recommendations

- **Impact of Quantifiable Recommendations.** The impact of implementing the recommendations related to energy uplift proposed by the MMU on the rates paid by participants would be significant. For example, in the first three months of 2015, the average rate paid by a DEC in the Eastern

Region would have been $0.354 per MWh, which is $2.440 per MWh, or 87.3 percent, lower than the actual average rate paid.

Section 4 Recommendations

The MMU recognizes that many of the issues addressed in the recommendations are being discussed in PJM stakeholder processes. Until new rules are in place, the MMU's recommendations and the reported status of those recommendations are based on the existing market rules.

- The MMU recommends that PJM not use closed loop interfaces to set zonal prices, rather than use nodal prices, to accommodate the inadequacies of the demand side resource capacity product or the inability of the LMP model to fully accommodate reactive issues. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that the implementation of closed loop interface constraints be studied carefully sufficiently in advance to identify issues and that closed loop interfaces be implemented only after such analysis, only after significant advance notice to the markets and only if the result is consistent with energy market fundamentals. (Priority: Medium. First reported 2013. Status: Not adopted. Stakeholder process.)
- The MMU recommends that PJM clearly identify and classify all reasons for incurring operating reserves in the Day-Ahead and the Real-Time Energy Markets and the associated operating reserve charges in order for all market participants to be made aware of the reasons for these costs and to help ensure a long term solution to the issue of how to allocate the costs of operating reserves. (Priority: Medium. First reported 2012. Status: Adopted partially.)
- The MMU recommends that PJM revise the current operating reserve confidentiality rules in order to allow the disclosure of complete information about the level of operating reserve charges by unit and the detailed reasons for the level of operating reserve credits by unit in the PJM region. (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends the elimination of the day-ahead operating reserve category to ensure that units receive an energy uplift payment based on their real-time output and not their day-ahead scheduled output. (Priority: Medium. First reported 2013. Status: Not adopted. Stakeholder process.)
- The MMU recommends reincorporating the use of net regulation revenues as an offset in the calculation of balancing operating reserve credits. (Priority: Medium. First reported 2013. Status: Not adopted. Stakeholder process.)
- The MMU recommends not compensating self-scheduled units for their startup cost when the units are scheduled by PJM to start before the self-scheduled hours. (Priority: Low. First reported 2013. Status: Not adopted. Stakeholder process.)
- The MMU recommends four modifications to the energy lost opportunity cost calculations:
  - The MMU recommends that the lost opportunity cost in the Energy and Ancillary Services Markets be calculated using the schedule on which the unit was scheduled to run in the Energy Market. (Priority: High. First reported 2012. Status: Not adopted. Stakeholder process.)
  - The MMU recommends including no load and startup costs as part of the total avoided costs in the calculation of lost opportunity cost credits paid to combustion turbines and diesels scheduled in the Day-Ahead Energy Market but not committed in real time. (Priority: Medium. First reported 2012. Status: Not adopted. Stakeholder process.)
  - The MMU recommends using the entire offer curve and not a single point on the offer curve to calculate energy lost opportunity cost. (Priority: Medium. First reported 2012. Status: Not adopted. Stakeholder process.)
  - The MMU recommends calculating LOC based on segments of hours not on an hourly basis in the calculation of credits paid to combustion turbines and diesels scheduled in the Day-Ahead Energy Market but not committed in real time. (Priority: Medium. First reported 2014. Status: Not adopted.)

- The MMU recommends that up-to congestion transactions be required to pay energy uplift charges. (Priority: High. First reported 2013. Status: Not adopted. Stakeholder process.)
- The MMU recommends eliminating the use of internal bilateral transactions (IBTs) in the calculation of deviations used to allocate balancing operating reserve charges. (Priority: High. First reported 2013. Status: Not adopted. Stakeholder process.)
- The MMU recommends allocating the energy uplift payments to units scheduled as must run in the Day-Ahead Energy Market for reasons other than voltage/reactive or black start services as a reliability charge to real-time load, real-time exports and real-time wheels. (Priority: Medium. First reported 2014. Status: Not adopted. Stakeholder process.)
- The MMU recommends reallocating the operating reserve credits paid to units supporting the Con Edison – PJM Transmission Service Agreements. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that the total cost of providing reactive support be categorized and allocated as reactive services. Reactive services credits should be calculated consistent with the operating reserve credits calculation. (Priority: Medium. First reported 2012. Status: Not adopted. Stakeholder process.)
- The MMU recommends including real-time exports and real-time wheels in the allocation of the cost of providing reactive support to the 500 kV system or above which is currently allocated to real-time RTO load. (Priority: Low. First reported Q2, 2014. Status: Not adopted.)
- The MMU recommends enhancing the current energy uplift allocation rules to reflect the elimination of day-ahead operating reserves, the timing of commitment decisions and the commitment reasons. (Priority: High. First reported Q1, 2014. Status: Not adopted. Stakeholder process.)

Section 4 Conclusion

Energy uplift is paid to market participants under specified conditions in order to ensure that resources are not required to operate for the PJM system at a loss. Referred to in PJM as day-ahead operating reserves, balancing operating reserves, energy lost opportunity cost credits, reactive services credits, synchronous condensing credits or black start services credits, these payments are intended to be one of the incentives to generation owners to offer their energy to the PJM Energy Market at marginal cost and to operate their units at the direction of PJM dispatchers. These credits are paid by PJM market participants as operating reserve charges, reactive services charges, synchronous condensing charges or black start charges.

From the perspective of those participants paying energy uplift charges, these costs are an unpredictable and unhedgeable component of participants' costs in PJM. While energy uplift charges are an appropriate part of the cost of energy, market efficiency would be improved by ensuring that the level and variability of these charges are as low as possible consistent with the reliable operation of the system and that the allocation of these charges reflects the reasons that the costs are incurred to the extent possible.

The goal should be to reflect the impact of physical constraints in market prices to the maximum extent possible and thus to reduce the necessity for out of market energy uplift payments. When units receive substantial revenues through energy uplift payments, these payments are not transparent to the market because of the current confidentiality rules. As a result, other market participants, including generation and transmission developers, do not have the opportunity to compete to displace them. As a result, substantial energy uplift payments to a concentrated group of units and organizations has persisted for more than ten years.

The level of energy uplift paid to specific units depends on the level of the unit's energy offer, the unit's operating parameters, the details of the rules which define payments and the decisions of PJM operators. Energy uplift payments result in part from decisions by PJM operators, who follow reliability requirements and market rules, to start units or to keep units operating even when hourly LMP is less than the offer price including energy, no load and startup costs. Energy uplift payments also result from units' operational parameters that may require PJM to schedule or commit resources during noneconomic hours. The balance of these costs not covered by energy revenues are collected as energy uplift rather than reflected in price as a result of the rules governing the determination of LMP.

PJM has recognized the importance of addressing the issues that result in large amounts of energy uplift charges. In 2013, PJM stakeholders created the Energy Market Uplift Senior Task Force (EMUSTF).[67] The main goals of the EMUSTF are to evaluate the causes of energy uplift payments, develop ways to minimize energy uplift payments while maintaining prices that are consistent with operational reliability needs, and explore the allocation of such payments. In December 2013, PJM stakeholders created the Market Implementation Committee – Energy/Reserve Pricing and Interchange Volatility group to address issues such as improving the incorporation of operators' actions in LMP.[68]

The MMU recommended and supports PJM in the reexamination of the allocation of uplift charges to participants to ensure that such charges are paid by all whose market actions result in the incurrence of such charges. For example, up-to congestion transactions continue to pay no energy uplift charges, which means that all others who pay these charges are paying too much. In addition, the netting of transactions against internal bilateral transactions should be eliminated.

PJM's goal should be to minimize the total level of energy uplift paid and to ensure that the associated charges are paid by all those whose market actions result in the incurrence of such charges. The goal should be to minimize the total incurred energy uplift charges and to increase the transactions over which those charges are spread in order to reduce the impact of energy uplift charges on markets. The result would be to reduce the level of per MWh charges, to reduce the uncertainty associated with uplift charges and to reduce the impact of energy uplift charges on decisions about how and when to participate in PJM markets.

67 See "Problem Statement – Energy Market Uplift Costs," Energy Market Uplift Senior Task Force (July 30, 2013) <http://www.pjm.com/~/media/committees-groups/task-forces/emustf/20130730/20130730-problem-statement-energy-market-uplift-costs.ashx>.

68 See "Problem Statement – Energy/Reserve Pricing and Interchange Volatility," Market Implementation Committee (December 11, 2013) <http://www.pjm.com/~/media/committees-groups/committees/mic/20131212/20131212-item-01b-energy-reserve-problem-statement-updated.ashx>.

Overview: Section 5, "Capacity Market"

RPM Capacity Market

Market Design

The Reliability Pricing Model (RPM) Capacity Market is a forward-looking, annual, locational market, with a must offer requirement for Existing Generation Capacity Resources and mandatory participation by load, with performance incentives, that includes clear market power mitigation rules and that permits the direct participation of demand-side resources.[69]

Under RPM, capacity obligations are annual. Base Residual Auctions (BRA) are held for Delivery Years that are three years in the future. Effective with the 2012/2013 Delivery Year, First, Second and Third Incremental Auctions (IA) are held for each Delivery Year.[70] Prior to the 2012/2013 Delivery Year, the Second Incremental Auction was conducted if PJM determined that an unforced capacity resource shortage exceeded 100 MW of unforced capacity due to a load forecast increase. Effective January 31, 2010, First, Second, and Third Incremental Auctions are conducted 20, 10, and three months prior to the Delivery Year.[71] Also effective for the 2012/2013 Delivery Year, a Conditional Incremental Auction may be held if there is a need to procure additional capacity resulting from a delay in a planned large transmission upgrade that was modeled in the BRA for the relevant Delivery Year.[72]

RPM prices are locational and may vary depending on transmission constraints.[73] Existing generation capable of qualifying as a capacity resource must be offered into RPM Auctions, except for resources owned by entities that elect the fixed resource requirement (FRR) option. Participation by LSEs is mandatory, except for those entities that elect the FRR option. 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. RPM rules provide performance incentives for

69 The terms *PJM Region, RTO Region* and *RTO* are synonymous in the *2015 Quarterly State of the Market Report for PJM: January through March*, Section 5, "Capacity Market," and include all capacity within the PJM footprint.

70 See 126 FERC ¶ 61,275 (2009) at P 86.

71 See *PJM Interconnection, L.L.C.*, Letter Order in Docket No. ER10-366-000 (January 22, 2010).

72 See 126 FERC ¶ 61,275 (2009) at P 88.

73 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.

generation, including the requirement to submit generator outage data and the linking of capacity payments to the level of unforced capacity, although the performance incentives are inadequate. 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, that define the minimum offer price, and that have flexible criteria for competitive offers by new entrants. Demand Resources and Energy Efficiency Resources may be offered directly into RPM Auctions and receive the clearing price without mitigation.

Market Structure

- **PJM Installed Capacity.** During the first three months of 2015, PJM installed capacity increased 65.5 MW or 0.0 percent from 183,724.1 MW on January 1 to 183,789.6 MW on March 31. Installed capacity includes net capacity imports and exports and can vary on a daily basis.
- **PJM Installed Capacity by Fuel Type.** Of the total installed capacity on March 31, 2015, 39.7 percent was coal; 30.8 percent was gas; 18.0 percent was nuclear; 5.8 percent was oil; 4.7 percent was hydroelectric; 0.4 percent was wind; 0.4 percent was solid waste; and 0.1 percent was solar.
- **Market Concentration.** In the 2015/2016 RPM Third Incremental Auction all participants in the total PJM market as well as the LDA RPM markets failed the three pivotal supplier (TPS) test.[74] Offer caps were applied to all sell offers for resources which were subject to mitigation when the Capacity Market Seller did not pass the test, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, increased the market clearing price.[75,76,77]

74 There are 27 Locational Deliverability Areas (LDAs) identified to recognize locational constraints as defined in "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region", Schedule 10.1. PJM determines, in advance of each BRA, whether the defined LDAs will be modeled in the given Delivery Year using the rules defined in OATT Attachment DD (Reliability Pricing Model) § 5.10(a)(ii).

75 See PJM. OATT Attachment DD § 6.5.

76 Prior to November 1, 2009, existing DR and EE resources were subject to market power mitigation in RPM Auctions. See 129 FERC ¶ 61,081 (2009) at P 30.

77 Effective January 31, 2011, the RPM rules related to market power mitigation were changed, including revising the definition for Planned Generation Capacity Resource and creating a new definition for Existing Generation Capacity Resource for purposes of the must-offer requirement and market power mitigation, and treating a proposed increase in the capability of a Generation Capacity Resource the same in terms of mitigation as a Planned Generation Capacity Resource. See 134 FERC ¶ 61,065 (2011).

- **Imports and Exports.** Of the 913.7 MW of imports in the 2015/2016 RPM Third Incremental Auction, all 913.7 MW cleared. Of the cleared imports, 966.0 MW (94.8 percent) were from MISO.
- **Demand-Side and Energy Efficiency Resources.** Capacity in the RPM load management programs was 13,858.3 MW for June 1, 2015 as a result of cleared capacity for Demand Resources and Energy Efficiency Resources in RPM Auctions for the 2015/2016 Delivery Year (16,643.3 MW) less replacement capacity (2,785.0 MW).

Market Conduct

- **2015/2016 RPM Third Incremental Auction.** Of the 214 generation resources which submitted offers, unit-specific offer caps were calculated for seven generation resources (3.3 percent). The MMU calculated offer caps for 23 generation resources (10.7 percent), of which 16 were based on the technology specific default (proxy) ACR values.

Market Performance

- The 2015/2016 RPM Third Incremental Auction was conducted in the first three months of 2015. In the 2015/2016 RPM Third Incremental Auction, the RTO clearing price for Annual Resources was $163.20 per MW-day. The weighted average capacity price for the 2015/2016 Delivery Year is $160.01 per MW-day, including all RPM Auctions for the 2015/2016 Delivery Year held through the first three months of 2015.
- For the 2014/2015 Delivery Year, RPM annual charges to load totaled approximately $7.3 billion.
- The Delivery Year weighted average capacity price was $116.55 per MW-day in 2013/2014 and $126.40 per MW-day in 2014/2015.

Generator Performance

- **Forced Outage Rates.** The average PJM EFORd for the first three months of 2015 was 9.5 percent, a decrease from 12.6 percent for the first three months of 2014.[78]

78 The generator performance analysis includes all PJM capacity resources for which there are data in the PJM generator availability data systems (GADS) database. This set of capacity resources may include generators in addition to those in the set of generators committed

- **Generator Performance Factors.** The PJM aggregate equivalent availability factor for 2015 was 86.4 percent, an increase from 83.5 percent for 2014.
- **Outages Deemed Outside Management Control (OMC).** In the first three months of 2015, 3.2 percent of forced outages were classified as OMC outages, and 0.0 percent of OMC outages were due to lack of fuel. OMC outages are excluded from the calculation of the forced outage rate used to calculate the unforced capacity that must be offered in the PJM Capacity Market.

Section 5 Recommendations[79]

The MMU recognizes that PJM has proposed the Capacity Performance construct to replace some of the existing core market rules and to address fundamental performance incentive issues. The MMU recognizes that the Capacity Performance construct addresses many of the MMU's recommendations. Until new rules are in place, the MMU's recommendations and the reported status of those recommendations are based on the existing capacity market rules.

- The MMU recommends the enforcement of a consistent definition of capacity resource. The MMU recommends that the requirement to be a physical resource be enforced and enhanced. The requirement to be a physical resource should apply at the time of auctions and should also constitute a commitment to be physical in the relevant Delivery Year. The requirement to be a physical resource should be applied to all resource types, including planned generation, demand resources and imports.[80,81] (Priority: High. First reported 2013. Status: Not adopted. Pending before FERC.)
- The MMU recommends that the definition of demand side resources be modified in order to ensure that such resources be fully substitutable for other generation capacity resources. Both the Limited and the Extended Summer DR products should be eliminated in order to ensure that the DR product has the same unlimited obligation to provide capacity year round as generation capacity resources. (Priority: High. First reported 2013. Status: Not adopted. Pending before FERC.)
- The MMU recommends that the use of the 2.5 percent demand adjustment (Short Term Resource Procurement Target) be terminated immediately. The 2.5 percent should be added back to the overall market demand curve. (Priority: Medium. First reported 2013. Status: Not adopted. Pending before FERC.)
- The MMU recommends that the test for determining modeled Locational Deliverability Areas in RPM be redefined. A detailed reliability analysis of all at risk units should be included in the redefined model. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that there be an explicit requirement that Capacity Resource offers in the Day-Ahead Energy Market be competitive, where competitive is defined to be the short run marginal cost of the units. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that clear, explicit operational protocols be defined for recalling the energy output of Capacity Resources when PJM is in an emergency condition. PJM has modified these protocols, but they need additional clarification and operational details. (Priority: Low. First reported 2010. Status: Not adopted.)
- The MMU recommends three changes with respect to capacity imports into PJM:
  - The MMU recommends that all capacity have firm transmission to the PJM border acquired prior to the offering in an RPM auction. (Priority: High. First reported 2014. Status: Not adopted. Pending before FERC.)
  - The MMU recommends that all capacity imports be required to be pseudo tied in order to ensure that imports are as close to full substitutes for internal, physical capacity resources as possible. (Priority: High. First reported 2014. Status: Not adopted. Pending before FERC.)

as capacity resources in RPM. Data is for the three months ending March 31, as downloaded from the PJM GADS database on April 28, 2015. 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.

79 The MMU has identified serious market design issues with RPM and the MMU has made specific recommendations to address those issues. These recommendations have been made in public reports. See Table 5-2.

80 See also Comments of the Independent Market Monitor for PJM. Docket No. ER14-503-000 (December 20, 2013).

81 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2013," <http://www.monitoringanalytics.com/reports/Reports/2013/IMM_Report_on_Capacity_Replacement_Activity_2_20130913.pdf> (September 13, 2013).

— The MMU recommends that all resources importing capacity into PJM accept a must offer commitment. (Priority: High. First reported 2014. Status: Not adopted. Pending before FERC.)

- The MMU recommends that the net revenue calculation used by PJM to calculate the net Cost of New Entry (CONE) VRR parameter reflect the actual flexibility of units in responding to price signals rather than using assumed fixed operating blocks that are not a result of actual unit limitations.[82,83] The result of reflecting the actual flexibility is higher net revenues, which affect the parameters of the RPM demand curve and market outcomes. (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that the rule requiring that relatively small proposed increases in the capability of a Generation Capacity Resource be treated as planned for purposes of mitigation and exempted from offer capping be removed. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that, as part of the MOPR unit specific standard of review, all projects be required to use the same basic modeling assumptions. That is the only way to ensure that projects compete on the basis of actual costs rather than on the basis of modeling assumptions.[84] (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends two changes to the RPM solution methodology related to make-whole payments and the iterative reconfiguration of the VRR curve:

— The MMU recommends changing the RPM solution methodology to explicitly incorporate the cost of make-whole payments in the objective function. (Priority: Medium. First reported 2014. Status: Not adopted.)

— The MMU also recommends changing the RPM solution methodology to define variables for the nesting relationships in the BRA optimization model directly rather than employing the current iterative approach, in order to improve the efficiency and stability. (Priority: Medium. First reported 2014. Status: Not adopted.)

- The MMU recommends improvements to the performance incentive requirements of RPM:

— The MMU recommends that Generation Capacity Resources be paid on the basis of whether they produce energy when called upon during any of the hours defined as critical. One hundred percent of capacity market revenue should be at risk rather than only fifty percent. (Priority: High. First reported 2013. Status: Not adopted. Pending before FERC.)

— The MMU recommends that a unit which is not capable of supplying energy consistent with its day-ahead offer should reflect an appropriate outage. (Priority: Medium. First reported 2013. Status: Not adopted. Pending before FERC.)

— The MMU recommends that PJM eliminate all OMC outages from the calculation of forced outage rates used for any purpose in the PJM Capacity Market. (Priority: Medium. First reported 2013. Status: Not adopted. Pending before FERC.)

— The MMU recommends that PJM eliminate the broad exception related to lack of gas during the winter period for single-fuel, natural gas-fired units.[85] (Priority: Medium. First reported 2013. Status: Not adopted. Pending before FERC.)

Section 5 Conclusion

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

82 See PJM Interconnection, L.L.C., Docket No. ER12-513 (December 1, 2011) ("Triennial Review").
83 See the *2012 State of the Market Report for PJM*, Volume II, Section 6, Net Revenue.
84 See 143 FERC ¶ 61,090 (2013) ("We encourage PJM and its stakeholders to consider, for example, whether the unit-specific review process would be more effective if PJM requires the use of common modeling assumptions for establishing unit-specific offer floors while, at the same time, allowing sellers to provide support for objective, individual cost advantages. Moreover, we encourage PJM and its stakeholders to consider these modifications to the unit-specific review process together with possible enhancements to the calculation of Net CONE."); see also, Comments of the Independent Market Monitor for PJM, Docket No. ER13-535-001 (March 25, 2013); Complaint of the Independent Market Monitor for PJM v. Unnamed Participant, Docket No. EL12-63-000 (May 1, 2012); Motion for Clarification of the Independent Market Monitor for PJM, Docket No. ER11-2875-000, et al. (February 17, 2012); Protest of the Independent Market Monitor for PJM, Docket No. ER11-2875-002 (June 2, 2011); Comments of the Independent Market Monitor for PJM, Docket Nos. EL11-20 and ER11-2875 (March 4, 2011).
85 For more on this issue and related incentive issues, see the MMU's White Paper included in: Monitoring Analytics, LLC and PJM Interconnection, LLC, "*Capacity in the PJM Market*," <http://www.monitoringanalytics.com/reports/Reports/2012/IMM_And_PJM_Capacity_White_Papers_On_OPSI_Issues_20120820.pdf> (August 20, 2012).

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, measured by the three pivotal supplier test results, but no exercise of market power in the PJM Capacity Market in the first three months of 2015. 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 in the first three months of 2015.

The MMU has identified serious market design issues with RPM and the MMU has made specific recommendations to address those issues.[86,87,88,89,90] In 2013 and 2014, the MMU prepared a number of RPM-related reports and testimony, shown in Table 5-2.

As an example of such reports, the MMU prepared a report that addresses and quantifies the impact on market outcomes in the Base Residual Auction (BRA) for the 2017/2018 Delivery Year of the Short-Term Resource Procurement Target (2.5 percent offset) and demand side resources both separately and together. (Demand side resources include Demand Resources, DR, and Energy Efficiency resources, EE.) The report demonstrates that the limited DR product and the 2.5 percent offset significantly suppress prices.[91]

The MMU continues to recommend that the use of the 2.5 percent demand adjustment be terminated immediately.[92] The 2.5 percent demand reduction is a barrier to entry in the capacity market. The logic of reducing demand in a market design that looks three years forward, to permit other resources to clear in Incremental Auctions, is not supportable and has no basis in economics.

86 See "Analysis of the 2013/2014 RPM Base Residual Auction Revised and Updated," <http://www.monitoringanalytics.com/reports/Reports/2010/Analysis_of_2013_2014_RPM_Base_Residual_Auction_20090920.pdf> (September 20, 2010).

87 See "Analysis of the 2014/2015 RPM Base Residual Auction," <http://www.monitoringanalytics.com/reports/Reports/2012/Analysis_of_2014_2015_RPM_Base_Residual_Auction_20120409.pdf> (April 9, 2012).

88 See "Analysis of the 2015/2016 RPM Base Residual Auction," <http://www.monitoringanalytics.com/reports/Reports/2013/Analysis_of_2015_2016_RPM_Base_Residual_Auction_20130924.pdf> (September 24, 2013).

89 See "Analysis of the 2016/2017 RPM Base Residual Auction," <http://www.monitoringanalytics.com/reports/Reports/2014/IMM_Analysis_of_the_20162017_RPM_Base_Residual_Auction_20140418.pdf> (April 18, 2014).

90 See "Analysis of the 2017/2018 RPM Base Residual Auction," <http://www.monitoringanalytics.com/reports/Reports/2014/IMM_Analysis_of_the_2017_2018_RPM_Base_Residual_Auction_20141006.pdf> (October 6, 2014).

91 See "The 2017/2018 RPM Base Residual Auction: Sensitivity Analyses Revised," <http://www.monitoringanalytics.com/reports/Reports/2014/IMM_20172018_RPM_BRA_Sensitivity_Analyses_Revised_20140826.pdf> (August 26, 2014).

92 See also the *Protest of the Independent Market Monitor for PJM*, Docket No. ER12-513 (December 22, 2011).

There are tradeoffs in using a one year forward or a three year forward design, but the design should be implemented on a consistent basis. Removing a portion of demand affects prices at the margin, which is where the critical signal to the market is determined.

The results of the report show that even when all DR is removed and the 2.5 percent offset is eliminated and holding everything else constant, prices would have risen to greater than net CONE but less than the maximum price and PJM's reliability target would have been maintained. This is a measure of the impact of the removal of DR and the 2.5 percent offset and is also a measure of the price suppression effect of DR and the 2.5 percent offset.

The fact that this set of sensitivity analyses holds everything else constant is important for considering the actual impacts of the simultaneous elimination of DR and the 2.5 percent offset. The results of these sensitivity analyses are worst case, in the sense that the increases in prices and reductions in quantities cleared are the maximum levels, because they do not include any market response which would mitigate the impact on prices and cleared quantities of eliminating DR. If both these adjustments had been made prior to the 2017/2018 BRA, it is likely that additional generation resources would have entered the market, that prices would likely have been lower than the prices in these sensitivity analyses and that reliability would have been greater than in these sensitivity analyses.

Overview: Section 6, "Demand Response"

- **Demand Response Jurisdiction.** In a panel decision issued May 23, 2014, the U.S. Court of Appeals for the District of Columbia Circuit vacated in its entirety Order No. 745, which provided for payment of demand-side resources at full LMP.[93] The decision calls into question the jurisdictional foundation for all demand response programs currently subject to FERC oversight, and, in particular, for those programs that involve FERC regulated payments to demand resources. *EPSA v. FERC* is now subject to

93 Electric Power Supply Association v. FERC, No. 11-1486, *petition for en banc review denied*; *see Demand Response Compensation in Organized Wholesale Energy Markets*, Order No. 745, FERC Stats. & Regs. ¶ 31,322 (2011); *order on reh'g*, Order No. 745-A, 137 FERC ¶ 61,215 (2011); *order on reh'g*, Order No. 745-B, 138 FERC 61,148 (2012).

a stay pending the Supreme Court's review of the decision in its October 2015 term. The Supreme Court granted certiorari on May 4, 2015.

FirstEnergy filed an amended complaint on September 22, 2014, that seeks to extend *EPSA v. FERC* to the PJM capacity markets, and would, if granted, eliminate tariff provisions that provide for the compensation of Demand Resources as a form of supply effective May 23, 2014, and require a rerun of the 2017/2018 Base Residual Auction.[94]

On March 31, 2015, the FERC rejected as premature certain tariff revisions filed by PJM on January 14, 2015, which had been intended to adapt the PJM demand response rules depending on the outcomes and timing of the outcomes on potential review of EPSA v. FERC and PJM's pending capacity performance proposal.[95]

- **Demand Response Activity.** Demand response is split into two main categories; economic and emergency. Emergency program revenue includes both capacity and energy revenue. The capacity market is still the primary source of revenue to participants in PJM demand response programs. In the first three months of 2015, capacity market revenue increased by $31.1 million, or 22.6 percent, from $137.8 million in the first three months of 2014 to $168.9 million in the first three months of 2015.[96] Emergency energy revenue decreased by $43.0 million, from $43.0 million in the first three months of 2014 to zero in the first three months of 2015. Economic program revenue is energy revenue only. Economic program credits decreased by $11.2 million, from $12.7 million in the first three months of 2014 to $1.6 million in the first three months of 2015, an 88 percent decrease.[97] Not all DR activities in the first three months of 2015 have been reported to PJM at the time of this report.

  All demand response energy payments are uplift. LMP does not cover demand response energy payments. Emergency demand response energy costs are paid by PJM market participants in proportion to their net purchases in the real-time market. Economic demand response energy costs are assigned to real-time exports from the PJM Region and real-time loads in each zone for which the load-weighted average real-time LMP for the hour during which the reduction occurred is greater than the price determined under the net benefits test for that month.[98]

- **Demand Response Market Concentration.** Economic demand response was highly concentrated in the first three months of 2014 and 2015. The HHI for economic demand response reductions increased from 7120 in the first three months of 2014 to 7899 in the first three months of 2015. Emergency demand response was moderately concentrated in the first three months of 2015. The HHI for emergency demand response registrations was 1760. In 2015, the four largest companies contributed 65.3 percent of all registered emergency demand response resources.

- **Locational Dispatch of Demand Resources.** Beginning with the 2014/2015 Delivery Year, demand resources are dispatchable for mandatory reduction on a subzonal basis, defined by zip codes, if the subzone is defined at least one day before dispatched. More locational dispatch of demand resources in a nodal market improves market efficiency. The goal should be nodal dispatch of demand resources.

Section 6 Recommendations

The MMU recognizes the substantial uncertainty related to the treatment of demand response in wholesale power markets which depends on Supreme Court review and on FERC treatment of PJM's Capacity Performance filing. The MMU recognizes that PJM has incorporated some of these recommendations in the Capacity Performance filing. The status of each recommendation reflects the status at the time of this report.

- The MMU recommends that, if demand response remains in the PJM market, there be only one demand response product, with an obligation to respond when called for all hours of the year, and that the demand response be on the demand side of the capacity market. (Priority: High. First reported 2013. Status: Not Adopted.[99] Pending before FERC.)

94 See FirstEnergy Service Company complaint, FERC Docket No. EL14-55-000, amending the complaint filed May 23, 2014.
95 150 FERC ¶ 61,251.
96 The total credits and MWh numbers for demand resources were calculated as of March 4th, 2015 and may change as a result of continued PJM billing updates.
97 Economic credits are synonymous with revenue received for reductions under the economic load response program.
98 PJM: "Manual 28: Operating Agreement Accounting," Revision 64 (April 11, 2014), p 70.
99 PJM's Capacity Performance proposal includes this change. See "Reforms to the Reliability Pricing Market ("RPM") and Related Rules in the PJM Open Access Transmission Tariff ("Tariff") and Reliability Assurance Agreement Among Load Serving Entities ("RAA")," Docket No. ER15-632-000 and "PJM Interconnection, L.L.C." Docket No. EL15-29-000.

- The MMU recommends that, if demand response remains in the PJM market, the emergency load response program be classified as an economic program, responding to economic price signals and not an emergency program responding only after an emergency is called. (Priority: High. First reported 2012. Status: Partially adopted.)
- The MMU recommends that, if demand response remains in the PJM market, a daily energy market must offer requirement apply to demand resources, comparable to the rule applicable to generation capacity resources.[100] (Priority: High. First reported 2013. Status: Not adopted. Pending before FERC.)
- The MMU recommends that, if demand response remains in the PJM market, demand response programs adopt an offer cap equal to the offer cap applicable to energy offers from generation capacity resources, currently $1,000 per MWh.[101] (Priority: High. First reported 2013. Status: Not adopted. Pending before FERC.)
- The MMU recommends that, if demand response remains in the PJM market, the lead times for demand resources be shortened to 30 minutes with an hour minimum dispatch for all resources. (Priority: Medium. First reported 2013. Status: Adopted in full, Q1, 2014.)
- The MMU recommends that, if demand response remains in the PJM market, demand resources be required to provide their nodal location on the electricity grid. (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that, if demand response remains in the PJM market, measurement and verification methods for demand resources be further modified to more accurately reflect compliance. (Priority: Medium. First reported 2012. Status: Not adopted.)
- The MMU recommends that, if demand response remains in the PJM market, compliance rules be revised to include submittal of all necessary hourly load data, and that negative values be included when calculating event compliance across hours and registrations. (Priority: Medium. First reported 2012. Status: Not adopted.)
- The MMU recommends that, if demand response remains in the PJM market, PJM adopt the ISO-NE five-minute metering requirements in order to ensure that dispatchers have the necessary information for reliability and that market payments to demand resources be calculated based on interval meter data at the site of the demand reductions.[102] (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that, if demand response remains in the PJM market, demand response event compliance be calculated for each hour and the penalty structure reflect hourly compliance. (Priority: Medium. First reported 2013. Status: Not adopted. Pending before FERC.)
- The MMU recommends that, if demand response remains in the PJM market, demand resources whose load drop method is designated as "Other" explicitly record the method of load drop. (Priority: Low. First reported 2013. Status: Adopted in full, Q2, 2014.)
- The MMU recommends that, if demand response remains in the PJM market, load management testing be initiated by PJM with limited warning to CSPs in order to more accurately represent the conditions of an emergency event. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends, as a preferred alternative to having PJM demand side programs, that demand response be on the demand side of the markets and that customers be able to avoid capacity and energy charges by not using capacity and energy at their discretion and that customer payments be determined only by metered load. (Priority: High. First reported 2014. Status: Not adopted. Pending before FERC.)

100 See "Complaint and Motion to Consolidate of the Independent Market Monitor for PJM," Docket No. EL14-20-000 (January 27, 2014) at 1.
101 *Id* at 1.
102 See ISO-NE Tariff, Section III, Market Rule 1, Appendix E1 and Appendix E2, "Demand Response," <http://www.iso-ne.com/regulatory/tariff/sect_3/mr1_append-e.pdf>. (Accessed February 17, 2015) ISO-NE requires that DR have an interval meter with five minute data reported to the ISO and each behind the meter generator is required to have a separate interval meter. After June 1, 2017, demand response resources in ISO-NE must also be registered at a single node.

Section 6 Conclusion

A fully functional demand side of the electricity market means that end use customers or their designated intermediaries will have the ability to see real time energy price signals in real time, will have the ability to react to real time prices in real time and will have the ability to receive the direct benefits or costs of changes in real time energy use. In addition, customers or their designated intermediaries will have the ability to see current capacity prices, will have the ability to react to capacity prices and will have the ability to receive the direct benefits or costs of changes in the demand for capacity. A functional demand side of these markets means that customers will have the ability to make decisions about levels of power consumption based both on the value of the uses of the power and on the actual cost of that power.

With exception of large wholesale customers in some areas, most customers in PJM are not on retail rates that directly expose them to the wholesale price of energy or capacity. As a result, most customers in PJM do not have the direct ability to see, respond to or benefit from a response to price signals in PJM's markets. PJM's demand side programs are generally designed to allow customers (or their intermediaries in the form of load serving entities (LSEs) or curtailment service providers (CSPs)) to either directly, or through intermediaries, be paid as if they were directly paying the wholesale price of energy and capacity and avoiding those prices when reducing load. PJM's demand side programs are designed to provide direct incentives for load resources to respond, via load reductions, to wholesale market price signals and/or system emergency events.

If retail markets reflected hourly wholesale locational prices and customers or their intermediaries received direct savings associated with reducing consumption in response to real time prices, there would not be a need for a PJM economic load response program, or for extensive measurement and verification protocols. In the transition to that point, however, as long as there are demand side programs, there is a need for robust measurement and verification techniques to ensure that transitional programs incent the desired behavior. The baseline methods used in PJM programs today are not adequate to determine and quantify deliberate actions taken to reduce consumption.

If demand resources are to continue competing directly with generation capacity resources in the PJM Capacity Market, the product must be defined such that it can actually serve as a substitute for generation. That is a prerequisite to a functional market design.

In order to be a substitute for generation, demand resources should be defined in PJM rules as an economic resource, as generation is defined. Demand resources should be required to offer in the day ahead market and should be called when the resources are required and prior to the declaration of an emergency. Demand resources should be available for every hour of the year and not be limited to a small number of hours.

In order to be a substitute for generation, demand resources should provide a nodal location and should be dispatched nodally to enhance the effectiveness of demand resources and to permit the efficient functioning of the energy market.

In order to be a substitute for generation, compliance by demand resources to PJM dispatch instructions should include both increases and decreases in load. The current method applied by PJM simply ignores increases in load and thus artificially overstates compliance.

As a preferred alternative, demand response would be on the demand side of the capacity market rather than on the supply side. Rather than complex demand side programs with their attendant complex and difficult to administer rules, customers would be able to avoid capacity and energy charges by not using capacity and energy at their discretion.

The long term appropriate end state for demand side resources in the PJM markets should be comparable to the demand side of any market. Customers should use energy as they wish and that usage will determine the amount of capacity and energy for which each customer pays. There would be no counterfactual measurement and verification.

Under this approach, customers that wish to avoid capacity payments would reduce their load during expected high load hours. Capacity costs would be assigned to LSEs and by LSEs to customers, based on actual load on the system during these critical hours. Customers wishing to avoid high energy prices would reduce their load during high price hours. Customers would pay for what they actually use, as measured by meters, rather than relying on flawed measurement and verification methods. No M&V estimates are required. No promises of future reductions which can only be verified by M&V are required. To the extent that customers enter into contracts with CSPs or LSEs to manage their payments, M&V can be negotiated as part of a bilateral commercial contract between a customer and its CSP or LSE.

This approach provides more flexibility to customers to limit usage at their discretion. There is no requirement to be available year round or every hour of every day. There is no 30 minute notice requirement. There is no requirement to offer energy into the day-ahead market. All decisions about interrupting are up to the customers only and they may enter into bilateral commercial arrangements with CSPs at their sole discretion. Customers would pay for capacity and energy depending solely on metered load.

A transition to this end state should be defined in order to ensure that appropriate levels of demand side response are incorporated in PJM's load forecasts and thus in the demand curve in the capacity market for the next three years. That transition should be defined by the PRD rules, modified as suggested by the Market Monitor.

This approach would work under the current RPM design and this approach would work under the CP design. This approach is entirely consistent with any Supreme Court decision on *EPSA* as it does not require FERC to have jurisdiction over the demand side. This approach will allow the Commission to more fully realize its overriding policy objective to create competitive and efficient wholesale energy markets.

Overview: Section 7, "Net Revenue"

Net Revenue

- Net revenues are significantly affected by fuel prices, energy prices and capacity prices. Coal and natural gas prices and energy prices were lower in the first three months of 2015 than in the first three months of 2014. Net revenues from the energy market for all plant types were significantly affected by the lower prices.
- In the first three months of 2015, average energy market net revenues decreased by 50 percent for a new CT, 44 percent for a new CC, 61 percent for a new CP, 72 percent for a new DS, 50 percent for a new nuclear plant, 26 percent for a new wind installation, and 13 percent for a new solar installation. The comparison to the first three months of 2014 reflects the very high net revenues in January 2014.

Section 7 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. The exact level of both aggregate and locational excess capacity is a function of the calculation methods used by RTOs and ISOs.

Overview: Section 8, "Environmental and Renewables"

Federal Environmental Regulation

- **EPA Mercury and Air Toxics Standards Rule.** On December 16, 2011, the U.S. Environmental Protection Agency (EPA) issued its Mercury and Air Toxics Standards rule (MATS), which applies the Clean Air Act (CAA) maximum achievable control technology (MACT) requirement to new or modified sources of emissions of mercury and arsenic, acid gas, nickel, selenium and cyanide.[103] The rule establishes a compliance deadline of April 16, 2015.

  In addition, in a related EPA rule issued on the same date regarding utility New Source Performance Standards (NSPS), the EPA requires new coal and oil fired electric utility generating units constructed after May 3, 2011, to comply with amended emission standards for SO_2, NO_X and filterable particulate matter (PM).

- **Air Quality Standards (NO_X and SO_2 Emissions).** The CAA requires each state to attain and maintain compliance with fine PM and ozone national ambient air quality standards (NAAQS). Much recent regulatory activity concerning emissions has concerned the development and implementation of a transport rule to address the CAA's requirement that each state prohibit emissions that significantly interfere with the ability of another state to meet NAAQS.[104]

  On April 29, 2014, the U.S. Supreme Court upheld EPA's Cross-State Air Pollution Rule (CSAPR) and on October 23, 2014, the U.S. Court of Appeals for the District of Columbia Circuit lifted the stay imposed on CSAPR, clearing the way for the EPA to implement this rule and to replace the Clean Air Interstate Rule (CAIR) now in effect.[105,106]

  On November 21, 2014, EPA issued a rule tolling by three years CSAPR's original deadlines. Compliance with CSAPR's Phase 1 emissions budgets is now required in 2015 and 2016 and CSAPR's Phase 2 emissions in 2017 and beyond.[107]

- **National Emission Standards for Reciprocating Internal Combustion Engines.** On May 1, 2015, the U.S. Court of Appeals for the District of Columbia Circuit reversed the portion of the final rule exempting 100 hours of run time for certain stationary reciprocating internal combustion engines (RICE) participating in emergency demand response programs from the otherwise applicable emission standards.[108] The Court held that "EPA acted arbitrarily and capriciously when it modified the National Emissions Standards and the Performance Standards to allow backup generators to operate without emissions controls for up to 100 hours per year as part of an emergency demand-response program."[109] Specifically, the Court found that EPA failed to consider arguments concerning the rule's "impact on the efficiency and reliability of the energy grid," including arguments raised by the MMU.[110]

- **Greenhouse Gas Emissions Rule.** On September 20, 2013, pursuant to Section 111(d) of the EPA Act, the EPA proposed standards placing national limits on the amount of CO_2 that new power plants would be allowed to emit.[111] Once GHG NSPS standards for CO_2 are in place, the CAA permits the EPA to regulate CO_2 emissions from existing sources.[112] The EPA issued a proposed rule for regulating CO_2 from certain existing power generation facilities on June 2, 2014, the Existing Stationary

103 *National Emission Standards for Hazardous Air Pollutants From Coal and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil Fuel Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units*, EPA Docket No. EPA-HQ-OAR-2009-0234, 77 Fed. Reg. 9304 (February 16, 2012).
104 CAA § 110(a)(2)(D)(i)(I).

105 See EPA et al. v. EME Homer City Generation, L.P. et al., 134 S. Ct. 1584 (2014), *reversing* 696 F.3d 7 (D.C. Cir. 2012).
106 Order, City Generation, L.P. EPA et al. v. EME Homer et al., No. 11-1302.
107 *Rulemaking to Amend Dates in Federal Implementation Plans Addressing Interstate Transport of Ozone and Fine Particulate Matter*, EPA-HQ-OAR-2009-0491 (Nov. 21, 2014).
108 Delaware Department of Natural Resources and Environmental Control (DENREC) v. EPA, Slip Op. No. 13-1093; *National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines; New Source Performance Standards for Stationary Internal Combustion Engines*, Final Rule, EPA Docket No. EPA-HQ-OAR-2008-0708, 78 Fed. Reg. 9403 (January 30, 2013).
109 DENREC v. EPA at 3, 20–21.
110 *Id.* at 22, citing Comments of the Independent Market Monitor for PJM, EPA Docket No. EPA-HQ-OAR-2008-0708 (August 9, 2012) at 2.
111 *Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units, Propose Rule*, EPA-HQ-OAR-2013-0495 ("GHG NSPS").
112 See CAA § 111(b)&(d).

Sources Notice of Proposed Rulemaking ("ESS NOPR").[113] The EPA refers to its rules directed at GHG under Section 111(d) as the "Clean Power Plan."

The ESS NOPR established interim and final emissions goals for each state that must be met by 2020 and 2030. The EPA plans to issue final rules on both the GHG NSPS and the ESS NOPR in the summer of 2015. Individual state plans likely will be submitted in the summer of 2017, while multistate plans likely will be submitted in the summer of 2018.

State Environmental Regulation

- **NJ High Electric Demand Day (HEDD) Rule.** New Jersey addressed the issue of NO_X emissions on peak energy demand days with a rule that defines peak energy usage days, referred to as high electric demand days or HEDD, and imposes operational restrictions and emissions control requirements on units responsible for significant NO_X emissions on such high energy demand days.[114] New Jersey's HEDD rule, which became effective May 19, 2009, applies to HEDD units, which include units that have a NO_X emissions rate on HEDD equal to or exceeding 0.15 lbs/MMBtu and lack identified emission control technologies.[115]
- **Illinois Air Quality Standards (NO_X, SO_2 and Hg).** The State of Illinois has promulgated its own standards for NO_X, SO_2 and Hg (mercury) known as Multi-Pollutant Standards ("MPS") and Combined Pollutants Standards ("CPS").[116] MPS and CPS establish standards that are more stringent and take effect earlier than comparable Federal regulations, such as the EPA MATS rule.

  The Illinois Pollution Control Board has granted variances with conditions for compliance with MPS/CPS for Illinois units included in or potentially included in PJM markets that may have impacted PJM markets.[117] In order to obtain variances, companies in PJM, such as Midwest Generation LLC, agreed to terms with the Illinois Pollution Control Board.[118]
- **Regional Greenhouse Gas Initiative (RGGI).** The Regional Greenhouse Gas Initiative (RGGI) is a cooperative effort by Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont to cap CO_2 emissions from power generation facilities and facilitate trading of emissions allowances. Auction prices in 2015 for the 2015-2017 compliance period were $5.41 per ton. The clearing price is equivalent to a price of $5.96 per metric tonne, the unit used in other carbon markets.

Emissions Controls in PJM Markets

Environmental regulations affect decisions about emission control investments in existing units, investment in new units and decisions to retire units lacking emission controls. As a result of environmental regulations and agreements to limit emissions, many PJM units burning fossil fuels have installed emission control technology. On March 31, 2015, 78.3 percent of coal steam MW had some type of FGD (flue-gas desulfurization) technology to reduce SO_2 emissions, while 99.5 percent of coal steam MW had some type of particulate control, and 92.7 percent of fossil fuel fired capacity in PJM had NO_x emission control technology.

State Renewable Portfolio Standards

Many PJM jurisdictions have enacted legislation to require that a defined percentage of retail suppliers' load be served by renewable resources, for which there are many standards and definitions. These are typically known as renewable portfolio standards, or RPS. As of March 31, 2015, Delaware, Illinois, Indiana, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, and Washington D.C. had renewable portfolio standards. Virginia has enacted a voluntary renewable portfolio standard. Kentucky and Tennessee have not enacted renewable portfolio standards. Ohio delayed a scheduled increase from 2.5 percent to 3.5 percent in its RPS standards from 2015 until 2017 and removed the 12.5 percent alternative energy requirement.

113 *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units*, EPA-HQ-OAR-2013-0602, 79 Fed. Reg. 34830 (June 18, 2014).
114 N.J.A.C. § 7:27-19.
115 CTs must have either water injection or selective catalytic reduction (SCR) controls; steam units must have either an SCR or selective non-catalytic reduction (SNCR).
116 35 Ill. Admin. Code §§ 225.233 (Multi-Pollutant Standard (MPS), 224.295 (Combined Pollutant Standard: Emissions Standards for NO_X and SO_2 (CPS)).
117 See, e.g., Midwest Generation, LLC, Opinion and Order of the Board, Docket No. PCB 13-24 (Variance-Air) (April 4, 2013); Midwest Generation, LLC, Opinion and Order of the Board, Docket No. PCB 12-121 (Variance-Air) (August 23, 2012).
118 See *Id.*

Ohio currently has an ongoing Ohio Energy Mandates Study Committee that is discussing the costs and benefits of the RPS as outlined in Senate Bill 310.[119] West Virginia had a voluntary standard, but the state Legislature repealed their renewable portfolio standard on January 22, 2015.

Renewable energy credits (RECs) and federal production tax credits provide out of market payments to qualifying resources, primarily wind and solar, which create an incentive to generate MWh until the LMP is equal to the marginal cost of producing power minus the credit received for each MWh. The credits provide an incentive to make negative energy offers and more generally provide an incentive to operate whenever possible. These subsidies affect the offer behavior and the operational behavior of these resources in PJM markets and thus the market prices and the mix of clearing resources.

Section 8 Conclusion

Environmental requirements and renewable energy mandates at both the federal and state levels have a significant impact on the cost of energy and capacity in PJM markets. Attempts to extend the definition of renewable energy to include nuclear power in order to provide subsidies to nuclear power could increase this impact if successful. Renewable energy credit markets are markets related to the production and purchase of wholesale power, but FERC has determined that RECs are not regulated under the Federal Power Act unless bundled with a wholesale sale of electric energy even if the transfer of the energy and the REC documented separately).[120] RECs affect prices in wholesale power markets. Some resources are not economic except for the ability to purchase or sell RECs. REC markets are not transparent. Data on REC prices and markets are not publicly available. RECs markets are, as an economic fact, integrated with PJM markets including energy and capacity markets, but are not formally recognized as part of PJM markets.

PJM markets provide a flexible mechanism for incorporating the costs of environmental controls and meeting environmental requirements in a cost effective manner. Costs for environmental controls are part of bids for capacity resources in the PJM capacity market. The costs of environmental permits are included in energy offers. PJM markets also provide a flexible mechanism that incorporates renewable resources and renewable energy credit markets, and ensure that renewable resources have access to a broad market. PJM markets provide efficient price signals that permit valuation of resources with very different characteristics when they provide the same product.

PJM markets could provide a flexible mechanism for states to comply with the EPA's Clean Power Plan, for example by incorporating a carbon price in unit offers which would be reflected in PJM's economic dispatch. The imposition of specific environmental dispatch rules, in contrast, poses a threat to economic dispatch and creates very difficult market power monitoring and mitigation issues.

Overview: Section 9, "Interchange Transactions"

Interchange Transaction Activity

- **Aggregate Imports and Exports in the Real-Time Energy Market.** During the first three months of 2015, PJM was a net importer of energy in the Real-Time Energy Market in all months.[121] In the first three months of 2015, the real-time net interchange of 5,031.9 GWh was higher than net interchange of -375.0 GWh in the first three months of 2014.
- **Aggregate Imports and Exports in the Day-Ahead Energy Market.** During the first three months of 2015, PJM was a net importer of energy in the Day-Ahead Energy Market in January and March, and a net exporter in February. In the first three months of 2015, the total day-ahead net interchange of 212.5 GWh was higher than net interchange of -4,982.0 GWh in the first three months of 2014. The large difference in

119 See Ohio Senate Bill 310.
120 See 139 FERC ¶ 61,061 at PP 18, 22 (2012) ("[W]e conclude that unbundled REC transactions fall outside of the Commission's jurisdiction under sections 201, 205 and 206 of the FPA. We further conclude that bundled REC transactions fall within the Commission's jurisdiction under sections 201, 205 and 206 of the FPA,… [A]lthough a transaction may not directly involve the transmission or sale of electric energy, the transaction could still fall under the Commission's jurisdiction because it is "in connection with" or "affects" jurisdictional rates or charges.").

121 Calculated values shown in Section 9, "Interchange Transactions," are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

the day-ahead net interchange totals was a result of the reduction in up-to congestion transaction volumes.[122]

- **Aggregate Imports and Exports in the Day-Ahead and the Real-Time Energy Market.** In the first three months of 2015, gross imports in the Day-Ahead Energy Market were 68.8 percent of gross imports in the Real-Time Energy Market (112.6 percent in the first three months of 2014). In the first three months of 2015, gross exports in the Day-Ahead Energy Market were 99.1 percent of the gross exports in the Real-Time Energy Market (145.6 percent in the first three months of 2014).
- **Interface Imports and Exports in the Real-Time Energy Market.** In the Real-Time Energy Market, in the first three months of 2015, there were net scheduled exports at eight of PJM's 20 interfaces.
- **Interface Pricing Point Imports and Exports in the Real-Time Energy Market.** In the Real-Time Energy Market, in the first three months of 2015, there were net scheduled exports at 10 of PJM's 18 interface pricing points eligible for real-time transactions.[123]
- **Interface Imports and Exports in the Day-Ahead Energy Market.** In the Day-Ahead Energy Market, in the first three months of 2015, there were net scheduled exports at eight of PJM's 20 interfaces.
- **Interface Pricing Point Imports and Exports in the Day-Ahead Energy Market.** In the Day-Ahead Energy Market, in the first three months of 2015, there were net scheduled exports at 10 of PJM's 19 interface pricing points eligible for day-ahead transactions.
- **Up-to Congestion Interface Pricing Point Imports and Exports in the Day-Ahead Energy Market.** In the Day-Ahead Market, in the first three months of 2015, up-to congestion transactions were net exports at five of PJM's 19 interface pricing points eligible for day-ahead transactions.
- **Loop Flows.** Actual flows are the metered power flows at an interface for a defined period. Scheduled flows are the power flows scheduled at an interface for a defined period. Inadvertent interchange is the difference between the total actual flows for the PJM system (net actual interchange) and the total scheduled flows for the PJM system (net scheduled interchange) for a defined period. Loop flows are the difference between actual and scheduled power flows at one or more specific interfaces.

  In the first three months of 2015, net scheduled interchange was 5,032 GWh and net actual interchange was 5,021 GWh, a difference of 11 GWh. In the first three months of 2014, net scheduled interchange was -375 GWh and net actual interchange was -243 GWh, a difference of 132 GWh. This difference is inadvertent interchange.

Interactions with Bordering Areas

PJM Interface Pricing with Organized Markets

- **PJM and MISO Interface Prices.** In the first three months of 2015, the direction of the hourly flow was consistent with the real-time hourly price differences between the PJM/MISO Interface and the MISO/PJM Interface in 55.5 percent of the hours.
- **PJM and New York ISO Interface Prices.** In the first three months of 2015, the direction of the hourly flow was consistent with the real-time hourly price differences between the PJM/NYIS Interface and the NYISO/PJM proxy bus in 48.2 percent of the hours.
- **Neptune Underwater Transmission Line to Long Island, New York.** In the first three months of 2015, the hourly flow (PJM to NYISO) was consistent with the real-time hourly price differences between the PJM Neptune Interface and the NYISO Neptune Bus in 64.3 percent of the hours.
- **Linden Variable Frequency Transformer (VFT) Facility.** In the first three months of 2015, the hourly flow (PJM to NYISO) was consistent with the real-time hourly price differences between the PJM Linden Interface and the NYISO Linden Bus in 64.7 percent of the hours.
- **Hudson DC Line.** In the first three months of 2015, the hourly flow (PJM to NYISO) was consistent with the real-time hourly price differences between the PJM Hudson Interface and the NYISO Hudson Bus in 30.0 percent of the hours.

122 On August 29, 2014, FERC issued an Order which created an obligation for UTCs to pay any uplift determined to be appropriate in the Commission review, effective September 8, 2014.
123 There is one interface pricing point eligible for day-ahead transaction scheduling only (NIPSCO).

Interchange Transaction Issues

- **PJM Transmission Loading Relief Procedures (TLRs).** PJM issued 16 TLRs of level 3a or higher in the first three months of 2015, compared to three such TLRs issued in the first three months of 2014.
- **Up-To Congestion.** On August 29, 2014, FERC issued an Order which created an obligation for UTCs to pay any uplift determined to be appropriate in the Commission review, effective September 8, 2014.[124]

  The average number of up-to congestion bids decreased by 71.4 percent and the average cleared volume of up-to congestion bids decreased by 72.3 percent in the first three months of 2015, compared to the first three months in 2014 (Figure 9-13).
- **45 Minute Schedule Duration Rule.** Effective May 19, 2014, PJM removed the 45 minute scheduling duration rule to become compliant with Order No. 764.[125,126] PJM and the MMU issued a statement indicating ongoing concern about market participants' scheduling behavior, and a commitment to address any scheduling behavior that raises operational or market manipulation concerns.[127]

Section 9 Recommendations

- The MMU recommends that PJM eliminate the IMO interface pricing point, and assign the transactions that originate or sink in the IESO balancing authority to the MISO interface pricing point. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM monitor, and adjust as necessary, the weights applied to the components of the interfaces to ensure that the interface prices reflect ongoing changes in system conditions and that loop flows are accounted for on a dynamic basis. The MMU also recommends that PJM review the mappings of external balancing authorities to individual interface pricing points to reflect changes to the impact of the external power source on PJM tie lines as a result of system topology changes. The MMU recommends that this review occur at least annually. (Priority: Low. First reported 2009. Status: Adopted partially, Q2 2014.)
- The MMU recommends that the submission deadline for real-time dispatchable transactions be modified from 1200 on the day prior, to three hours prior to the requested start time, and that the minimum duration be modified from one hour to 15 minutes. These changes would give PJM a more flexible product that could be utilized to meet load in the most economic manner. (Priority: Medium. First reported Q3 2014. Status: Not adopted.)
- The MMU recommends that PJM explore an interchange optimization solution with its neighboring balancing authorities that remove the need for market participants to schedule physical transactions across seams. Such a solution would include an optimized joint dispatch approach that treats seams between balancing authorizes as constraints, similar to any other constraint within an LMP market. (Priority: Medium. First reported Q3 2014. Status: Not adopted.)
- The MMU recommends that PJM permit unlimited spot market imports as well as unlimited non-firm point-to-point willing to pay congestion imports and exports at all PJM Interfaces in order to improve the efficiency of the market. (Priority: Medium. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM implement a validation method for submitted transactions that would prohibit market participants from breaking transactions into smaller segments to defeat the interface pricing rule and receive higher prices (for imports) or lower prices (for exports) from PJM resulting from the inability to identify the true source or sink of the transaction. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that the validation method also require market participants to submit transactions on market paths that reflect the expected actual power flow in order to reduce unscheduled loop flows. (Priority: Medium. First reported 2013. Status: Not adopted.)

124 148 FERC ¶ 61,144 (2014). *Order Instituting Section 206 Proceeding and Establishing Procedures.*
125 *Integration of Variable Energy Resources*, Order No. 764, 139 FERC ¶ 61,246 (2012), *order on reh'g*, Order No. 764-A, 141 FERC ¶ 61231 (2012).
126 *See* Letter Order, Docket No. ER14-381-000 (June 30, 2014).
127 *See* joint statement of PJM and the MMU re Interchange Scheduling issued July 29, 2014, which can be accessed at: <http://www.pjm.com/~/media/documents/reports/20140729-pjm-imm-joint-statement-on-interchange-scheduling.ashx>.

- The MMU recommends that PJM implement rules to prevent sham scheduling. The MMU's proposed validation rules would address sham scheduling. (Priority: High. First reported 2012. Status: Not adopted. Stakeholder process.)
- The MMU recommends that PJM eliminate the NIPSCO and Southeast interface pricing points from the Day-Ahead and Real-Time Energy Markets and, with VACAR, assign the transactions created under the reserve sharing agreement to the SouthIMP/EXP pricing point. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM immediately provide the required 12-month notice to Duke Energy Progress (DEP) to unilaterally terminate the Joint Operating Agreement. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM and MISO work together to align interface pricing definitions, using the same number of external buses and selecting buses in close proximity on either side of the border with comparable bus weights. (Priority: Medium. First reported 2012. Status: Adopted partially, Q4 2013.)
- The MMU recommends that PJM implement additional business rules to remove the incentive to engage in sham scheduling activities using the PJM/IMO interface price. (Priority: Medium. First reported 2014. Status: Not adopted. Stakeholder process.)
- The MMU recommends that PJM file revisions to the marginal loss surplus allocation method to fully comply with the February 24, 2009, Order. The MMU recommends that marginal loss surplus allocations be capped such that the marginal loss surplus credits cannot exceed the contributions made to the fixed costs of the transmission system for any reason. (Priority: Medium. First reported 2014. Status: Not adopted.)

Section 9 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 congestion offsets (FTRs and ARRs in PJM) and transparent, least cost, security constrained economic dispatch for all available generation. Non-market areas do not include these features. The market areas are extremely transparent and the non-market areas are not transparent.

The MMU's recommendations related to transactions with external balancing authorities all share the goal of improving the economic efficiency of interchange transactions. The standard of comparison is an LMP market. In an LMP market, redispatch based on LMP and generator offers results in an efficient dispatch and efficient prices.

Overview: Section 10, "Ancillary Services"

Primary Reserve

Primary reserve is PJM's implementation of the NERC 15-minute contingency reserve requirement. PJM's primary reserves are made up of resources, both synchronized and non-synchronized, that can provide energy within ten minutes.

Market Structure

- **Supply.** Primary reserve is satisfied by both synchronized reserve (generation or demand response currently synchronized to the grid and available within ten minutes), and non-synchronized reserve (generation currently off-line but can be started and provide energy within ten minutes).
- **Demand.** The PJM primary reserve requirement is 150 percent of the largest contingency. The primary reserve requirement in the RTO Reserve Zone was raised on January 8, 2015, to 2,175 MW of which at least 1,700 MW must be available within the Mid-Atlantic Dominion (MAD) subzone. Adjustments to the primary reserve requirement can occur when grid maintenance or outages change the largest contingency. The actual

demand for primary reserve in the RTO in January through March 2015 was 2,299.5 MW. The actual demand for primary reserve in the MAD subzone in January through March 2015 was 1,714.4 MW.

Tier 1 Synchronized Reserve

Synchronized reserve is energy or demand reduction synchronized to the grid and capable of increasing output or decreasing load within ten minutes. Synchronized reserve is of two distinct types, tier 1 and tier 2. Tier 1 synchronized reserve counts as part of PJM's primary reserve requirement and is the capability of on-line resources following economic dispatch to ramp up in ten minutes from their current output in response to a synchronized reserve event.

- **Supply.** No offers are made for tier 1 synchronized reserve. The market solution calculates tier 1 synchronized reserve as available 10-minute ramp from the energy dispatch. In the first three months of 2015, there was an average hourly supply of 1,433.0 MW of tier 1 for the RTO synchronized reserve zone, and an average hourly supply of 601.9 MW of tier 1 in the Mid-Atlantic Dominion subzone.

- **Demand.** The default hourly required synchronized reserve requirement is 1,700 MW in the RTO Reserve Zone and 1,450 MW for the Mid-Atlantic Dominion Reserve subzone.

- **Tier 1 Synchronized Reserve Event Response.** Tier 1 synchronized reserve is paid when a synchronized reserve event occurs and it responds. The synchronized reserve event response credits for tier 1 response are independent of the tier 1 estimated, independent of the synchronized reserve market clearing price, and independent of the non-synchronized reserve market clearing price.

  Of tier 1 synchronized reserve eligible for payment in Settlements, 66.3 percent actually responded during the seven distinct synchronized reserve events 10 minutes or longer in the first three months of 2015. PJM made changes to the way it calculated tier 1 MW for settlements in July 2014. These changes improved the response rate.

- **Issues.** The competitive price for tier 1 synchronized reserves is zero, as there is no incremental cost associated with the ability to ramp up from the current economic dispatch point. A tariff change included in the shortage pricing tariff changes (October 1, 2012) added the requirement to pay tier 1 synchronized reserve the tier 2 synchronized reserve market clearing price whenever the non-synchronized reserve market clearing price rises above zero.

  The rationale for this change was and is unclear but it has had a significant impact on the cost of tier 1 synchronized reserves, resulting in a windfall payment of $26,576,359 to tier 1 resources in 2014, and $17,877,658 in the first three months of 2015.

Tier 2 Synchronized Reserve Market

Tier 2 synchronized reserve is part of primary reserve (ten minute availability) and is comprised of resources that are synchronized to the grid, that incur costs to be synchronized, that have an obligation to respond with corresponding penalties, and that must be dispatched in order to satisfy the synchronized reserve requirement. When the synchronized reserve requirement cannot be filled with tier 1 synchronized reserve, PJM conducts a market to satisfy the requirement with tier 2 synchronized reserve. The Tier 2 Synchronized Reserve Market includes the PJM RTO Reserve Zone and a subzone, the Mid-Atlantic Dominion Reserve subzone (MAD).

Market Structure

- **Supply.** In the first three months of 2015, the supply of offered and eligible synchronized reserve was sufficient to cover the requirement in both the RTO Reserve Zone and the Mid-Atlantic Dominion Reserve subzone.

- **Demand.** The default hourly required synchronized reserve requirement was 1,450 MW in both the RTO Reserve Zone and the Mid-Atlantic Dominion Reserve subzone.

- **Market Concentration.** In the first three months of 2015, the weighted average HHI for cleared tier 2 synchronized reserve in the Mid-Atlantic Dominion subzone was 4357 which is classified as highly concentrated.

The MMU calculates that 56.2 percent of hours would have failed a three pivotal supplier test in the Mid-Atlantic Dominion subzone.

In the first three months of 2015, the weighted average HHI for cleared tier 2 synchronized reserve in the RTO Synchronized Reserve Zone was 5123 which is classified as highly concentrated. The MMU calculates that 35.0 percent of hours would have failed a three pivotal supplier test in the RTO Synchronized Reserve Zone.

The MMU concludes from these results that both the Mid-Atlantic Dominion subzone Tier 2 Synchronized Reserve Market and the RTO Synchronized Reserve Zone Market were characterized by structural market power in the first three months of 2015.

Market Conduct

- **Offers.** Tier 2 synchronized reserve offers from generating units are subject to an offer cap of marginal cost plus $7.50 per MW, plus opportunity cost, which is calculated by PJM.

Market Performance

- **Price.** The weighted average price for tier 2 synchronized reserve for all cleared hours in the Mid-Atlantic Dominion (MAD) subzone was $16.34 per MW in the first three months of 2015, a decrease of $10.12 (40 percent) from the first three months of 2014.

  The weighted average price for tier 2 synchronized reserve for all cleared hours in the RTO Synchronized Reserve Zone was $16.53 per MW in the first three months of 2015, a decrease of $34.37 from January through March 2014.

Non-Synchronized Reserve Market

Non-synchronized reserve is part of primary reserve and includes the same two markets, the RTO Reserve Zone and the Mid-Atlantic Dominion Reserve subzone (MAD). Non-synchronized reserve is comprised of non-emergency energy resources not currently synchronized to the grid that can provide energy within ten minutes. Non-synchronized reserve is available to fill the primary reserve requirement above the synchronized reserve requirement.

Market Structure

- **Supply.** In the first three months of 2015, the supply of eligible non-synchronized reserve was 3,764.3 MW in MAD and 6,721.0 in the RTO. This supply was sufficient to cover the primary reserve requirement in both the RTO Reserve Zone and the Mid-Atlantic Dominion Reserve subzone.

- **Demand.** In the RTO Zone, the market cleared an hourly average of 537.1 MW of non-synchronized reserve in the first three months of 2015. In the MAD subzone, the market cleared an hourly average of 490.0 MW of non-synchronized reserve.

Market Conduct

- **Offers.** No offers are made for non-synchronized reserve. Non-emergency generation resources that are available to provide energy and can start in 10 minutes or less are considered available for non-synchronized reserves by the market solution software.

Market Performance

- **Price.** There are no offers for non-synchronized reserve. The non-synchronized reserve price is determined by the opportunity cost of the marginal non-synchronized reserve unit. The non-synchronized reserve weighted average price for all cleared hours in the RTO Reserve Zone was $3.25 per MW in the first three months of 2015 and in 76.8 percent of hours the market clearing price was $0. The non-synchronized reserve weighted average price for all cleared hours in the Mid-Atlantic Dominion (MAD) subzone was $2.76 and in 75.7 percent of hours the market clearing price was $0.

Secondary Reserve (Day-Ahead Scheduling Reserve)

PJM maintains a day-ahead, offer based market for 30-minute secondary reserve, designed to provide price signals to encourage resources to provide 30-minute reserve.[128] The DASR Market has no performance obligations.

Market Structure

- **Concentration.** In the first three months of 2015, zero hours in the DASR Market would have failed the three pivotal supplier test.
- **Supply.** The DASR Market is a must offer market. Any resources that do not make an offer have their offer set to $0 per MW. DASR is calculated by the day-ahead market solution as the lesser of the thirty minute energy ramp rate or the emergency maximum MW minus the day-ahead dispatch point for all on-line units. In the first three months of 2015, the average available hourly DASR was 38,116 MW.
- **Demand.** The DASR requirement in 2015 is 5.93 percent of peak load forecast, down from 6.27 percent in 2014. The average DASR MW purchased was 6,303 MW per hour in the first three months of 2015.

Market Conduct

- **Withholding.** Economic withholding remains an issue in the DASR Market. The direct marginal cost of providing DASR is zero. All offers greater than zero constitute economic withholding. As of March 31, 2015, 9.6 percent of resources offered DASR at levels above $5 per MW.
- **DR.** Demand resources are eligible to participate in the DASR Market. Six demand resources entered offers for DASR.

Market Performance

- **Price.** The weighted average DASR market clearing price in January through March 2015 was $0.76 per MW. This is a significant increase from the $0.06 per MW of the first three months of 2014.

Regulation Market

The PJM Regulation Market is a single RT market. Regulation is provided by demand response and generation resources that qualify to follow a regulation signal (RegA or RegD). PJM jointly optimizes regulation with synchronized reserve and energy to provide all three services at least cost. The PJM Regulation Market design includes three clearing price components (capability or RMCCP, performance or RMPCP, and lost opportunity cost or LOC), the rate of substitution between RegA and RegD resources (marginal benefit factor) and a measure of the quality of response (performance score) by a regulation resource to a regulation signal. The marginal benefit factor and performance score translate a resource's capability (actual) MW into effective MW.

Market Structure

- **Supply.** In the first three months of 2015, the average hourly eligible supply of regulation was 1,154 actual MW (898 effective MW). This is a decrease of 224 actual MW (117 effective MW) from the same period of 2014, when the average hourly eligible supply of regulation was 1,377 actual MW (1,016 effective MW).
- **Demand.** The average hourly regulation demand was 648 actual MW in the first three months of 2015. This is a 37 actual MW (0 effective MW) decrease in the average hourly regulation demand of 685 actual MW (664 effective MW) from the same period of 2014.
- **Supply and Demand.** The ratio of offered and eligible regulation to regulation required averaged 1.78. This is an 11.5 percent decrease from the same period of 2014 when the ratio was 2.01.
- **Market Concentration.** In the first three months of 2015, the PJM Regulation Market had a weighted average Herfindahl-Hirschman Index (HHI) of 1545 which is classified as moderately concentrated. In the first three months of 2015, the three pivotal supplier test was failed in 97 percent of hours.

128 See PJM. "Manual 35, Definitions and Acronyms," Revision 23, (April 11, 2014), p. 22.

Market Conduct

- **Offers.** Daily regulation offer prices are submitted for each unit by the unit owner. Owners are required to submit a cost offer along with cost parameters to verify the offer, and may optionally submit a price offer. Offers include both a capability offer and a performance offer. Owners must specify which signal type the unit will be following, RegA or RegD.[129] In the first three months of 2015, there were 231 resources following the RegA signal and 42 resources following the RegD signal.

Market Performance

- **Price and Cost.** The weighted average clearing price for regulation was \$48.66 per MW of regulation in the first three months of 2015, a decrease of \$43.28 per MW of regulation, or 47.1 percent, from the same period of 2014. The cost of regulation in the first three months of 2015 was \$59.15 per MW of regulation, a decrease of \$51.87 per MW of regulation, or 46.7 percent, from the same period of 2014. The decreases in regulation price and regulation cost resulted primarily from high prices and costs in the first three months of 2014, particularly in January.
- **RMCP Credits.** RegD resources continue to be incorrectly compensated relative to RegA resources due to an inconsistent application of the marginal benefit factor in the optimization, assignment, pricing, and settlement processes. If the Regulation Market were functioning efficiently, RegD and RegA resources would be paid equally per effective MW.
- **Marginal Benefit Factor Function.** The marginal benefit factor measures the substitutability of RegD resources for RegA resources in satisfying the regulation requirement. The regulation market's effectiveness and efficiency depends on the marginal benefit factor function being properly defined based on the actual tradeoff between RegA and RegD MW in providing regulation. Current regulation performance indicates that the marginal benefit factor function used by PJM is incorrectly describing the operational relationship between RegA and RegD for purposes of providing regulation service.

129 See the *2014 State of the Market Report for PJM*, Volume II, Appendix F "Ancillary Services Markets."

- **Inconsistent accounting of RegD effective MW.** The MMU has determined that the current market optimization/market solution does not correctly account for the amount of effective MW being provided by RegD. Rather than calculating the total effective MW contribution of RegD MW on the basis of the area under the marginal benefit function curve, the current regulation market optimization assigns all RegD resources with the same effective price the lowest marginal benefit factor associated with last RegD MW at that price. The incorrect accounting of effective MW within the optimization construct will result in the purchase of more than the efficient level of RegD necessary to meet PJM's regulation requirement.

Black Start Service

Black start service is required for the reliable restoration of the grid following a blackout. 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 to automatically remain operating at reduced levels when disconnected from the grid.[130]

In the first three months of 2015, total black start charges were \$15.0 million with \$10.3 million in revenue requirement charges and \$4.7 million in operating reserve charges. Black start revenue requirements for black start units consist of fixed black start service costs, variable black start service costs, training costs, fuel storage costs, and an incentive factor. Black start operating reserve charges are paid to units scheduled in the Day-Ahead Energy Market or committed in real time to provide black start service under the automatic load rejection (ALR) option or for black start testing. Black start zonal charges in the first three months of 2015 ranged from \$0.04 per MW-day in the PPL Zone (total charges were \$31,710) to \$4.55 per MW-day in the BGE Zone (total charges were \$2,727,337).

Reactive

Reactive service, reactive supply and voltage control from generation or other sources service, is provided by generation and other sources of reactive power

130 OATT Schedule 1 § 1.3BB.

(measured in VAR). Reactive power helps maintain appropriate voltages on the transmission system and is essential to the flow of real power (measured in MW).

In the first three months of 2015, total reactive service charges were $76.1 million, a 2.2 percent decrease from the first three months of 2014 level of $77.8 million. Revenue requirement charges decreased from $70.3 million to $69.9 million and operating reserve charges fell from $7.5 million to $6.3 million. Total charges in the first three months of 2015 ranged from $1.8 thousand in the RECO Zone to $10.4 million in the AEP Zone. Reactive service revenue requirements are based on FERC-approved filings. Reactive service operating reserve charges are paid for scheduling in the Day-Ahead Energy Market and committing in real time units that provide reactive service.

Section 10 Recommendations

- The MMU recommends that the Regulation Market be modified to incorporate a consistent application of the marginal benefit factor throughout the optimization, assignment and settlement process. (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that the rule requiring the payment of tier 1 synchronized reserve resources when the non-synchronized reserve price is above zero be eliminated immediately. (Priority: High. First reported 2013. Status: Not adopted. Stakeholder process.)
- The MMU recommends that no payments be made to tier 1 resources if they are deselected in the PJM market solution. (Priority: High. First reported Q3, 2014. Status: Adopted July 2014.)
- The MMU recommends that the tier 2 synchronized reserve must-offer provision of scarcity pricing be enforced. As of the end of December 31, 2014 compliance with the tier 2 must-offer provision was 99.5 percent. (Priority: Medium. First reported 2013. Status: Adopted partially.)
- The MMU recommends that PJM be more explicit about why tier 1 biasing is used in the optimized solution to the Tier 2 Synchronized Reserve Market. The MMU recommends that PJM define rules for calculating available tier 1 MW and for the use of biasing during any phase of the market solution and then identify the relevant rule for each instance of biasing. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM determine why secondary reserve was either unavailable or not dispatched on September 10, 2013, January 6, 2014, and January 7, 2014, and that PJM replace the DASR Market with a real time secondary reserve product that is available and dispatchable in real time. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM revise the current confidentiality rules in order to specifically allow a more transparent disclosure of information regarding black start resources and their associated payments in PJM. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that the three pivotal supplier test be incorporated in the DASR Market. (Priority: Low. First reported 2012. Status: Not adopted.)

Section 10 Conclusion

While the design of the Regulation Market was significantly improved with changes introduced October 1, 2012, a number of issues remain. The market results continue to include the incorrect definition of opportunity cost. Further, the market design has failed to correctly incorporate the marginal benefit factor in optimization, pricing and settlement. Instead, the market design makes use of the marginal benefit factor in the optimization and pricing, but a mileage ratio multiplier in settlement. This failure to correctly incorporate marginal benefit factor into the current Regulation Market design is causing effective MW provided by RegD resources to be underpaid per effective MW. These issues have led to the MMU's conclusion that the Regulation Market design, as currently implemented, is flawed.

The structure of each Tier 2 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. 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. Compliance with calls to respond to actual synchronized reserve events has been an issue. Compliance with the synchronized reserve must-offer requirement has also been an issue.

The shortage pricing rule that requires market participants to pay tier 1 synchronized reserve the tier 2 synchronized reserve price when the nonsynchronized reserve price is greater than zero, is inefficient and results in a windfall payment to the holders of tier 1 synchronized reserve resources. Such tier 1 resources have no obligation to perform and pay no penalties if they do not perform. Such resources are not tier 2 resources, although they have the option to offer as tier 2, to take on tier 2 obligations and to be paid as tier 2. Application of this rule added $80.0 million to the cost of primary reserve in 2014.

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.

The MMU concludes that the new Regulation Market results were competitive. The MMU concludes that the Synchronized Reserve Market results were competitive. The MMU concludes that the DASR Market results were competitive.

Overview: Section 11, “Congestion and Marginal Losses”

Congestion Cost

- **Total Congestion.** Total congestion costs decreased by $603.6 million or 48.8 percent, from $1,231.6 million in the first three months of 2014 to $632.5 million in the first three months of 2015.
- **Day-Ahead Congestion.** Day-ahead congestion costs decreased by $660.0 million or 46.0 percent, from $1,433.3 million in the first three months of 2014 to $773.4 million in the first three months of 2015.
- **Balancing Congestion.** Balancing congestion costs increased by $56.4 million or 28.6 percent, from -$197.2 million in the first three months of 2014 to -$140.9 million in the first three months of 2015.
- **Real-Time Congestion.** Real-time congestion costs decreased by $891.4 million or 60.6 percent, from $1,470.4 million in the first three months of 2014 to $578.9 million in the first three months of 2015.
- **Monthly Congestion.** In 2015, 68.0 percent ($429.8 million) of total congestion cost was incurred in February and 32.0 percent ($202.7 million) of total congestion cost was incurred in the months of January and March. Monthly total congestion costs in the first three months of 2015 ranged from $70.3 million in March to $429.8 million in February.
- **Geographic Differences in CLMP.** Differences in CLMP among eastern, southern and western control zones in PJM were primarily a result of congestion on the 5004/5005 Interface, the Bedington - Black Oak Interface, the AEP - DOM Interface, the AP South Interface, and the Joshua Falls transformer.
- **Congestion Frequency.** Congestion frequency continued to be significantly higher in the Day-Ahead Energy Market than in the Real-Time Energy Market in the first three months of 2015. The number of congestion event hours in the Day-Ahead Energy Market was about five times higher than the number of congestion event hours in the Real-Time Energy Market.

Day-ahead congestion frequency decreased by 55.7 percent from 113,666 congestion event hours in the first three months of 2014 to 50,385 congestion event hours in the first three months of 2015.

Real-time congestion frequency decreased by 5.1 percent from 10,262 congestion event hours in the first three months of 2014 to 9,735 congestion event hours in the first three months of 2015.

- **Congested Facilities.** Day-ahead, congestion-event hours decreased on all types of congestion facilities. Real-time, congestion-event hours increased on line and transformer facilities and decrease on flowgate and interface facilities.

  The 5004/5005 Interface was the largest contributor to congestion costs in the first three months of 2015. With $87.1 million in total congestion costs, it accounted for 13.8 percent of the total PJM congestion costs in the first three months of 2015.

- **Zonal Congestion.** AEP had the largest total congestion costs among all control zones in the first three months of 2015. AEP had $212.3 million in total congestion costs, comprised of -$367.1 million in total load congestion payments, -$593.5 million in total generation congestion credits and -$14.1 million in explicit congestion costs. The AEP - DOM Interface, the Joshua Falls transformer, the 5004/5005 Interface, the Bedington - Black Oak Interface and the Mahans Lane – Tidd line contributed $116.6 million, or 54.9 percent of the total AEP control zone congestion costs.

- **Ownership.** In the first three months of 2015, financial entities as a group were net recipients of congestion credits, and physical entities were net payers of congestion charges. Explicit costs are the primary source of congestion credits to financial entities. In the first three months of 2015, financial entities received $74.9 million in congestion credits, a decrease of $112.0 million or 59.9 percent compared to the first three months of 2014. In the first three months of 2015, physical entities paid $707.4 million in congestion charges, a decrease of $715.6 million or 50.3 percent compared to the first three months of 2014.UTCs are in the explicit cost category and comprise most of that category. The total explicit cost is equal to day-ahead explicit cost plus balancing explicit cost. In the first three months of 2015, the total explicit cost is -$89.5 million and 120.9 percent of the total explicit cost is comprised of congestion cost by UTCs, which is -$108.2 million.

Marginal Loss Cost

- **Total Marginal Loss Costs.** Total marginal loss costs decreased by $350.8 million or 45.2 percent, from $775.9 million in the first three months of 2014 to $425.1 million in the first three months of 2015. Total marginal loss costs decreased because of the distribution of high load and outages caused by cold weather in January 2014. The loss MW in PJM decreased 4.2 percent, from 5,352 GWh in the first three months of 2014 to 5,127 GWh in the first three months of 2015. The loss component of LMP remained constant, $0.03 in the first three months of 2014 and $0.03 in the first three months of 2015.

- **Monthly Total Marginal Loss Costs.** Monthly total marginal loss costs in the first three months of 2015 ranged from $93.2 million in March to $220.3 million in February.

- **Day-Ahead Marginal Loss Costs.** Day-ahead marginal loss costs decreased by $399.2 million or 48.0 percent, from $831.1 million in the first three months of 2014 to $432.0 million in the first three months of 2015.

- **Balancing Marginal Loss Costs.** Balancing marginal loss costs increased by $48.4 million or 87.6 percent, from -$55.3 million in the first three months of 2014 to -$6.9 million in the first three months of 2015.

- **Marginal Loss Credits.** The marginal loss credits decreased in the first three months of 2015 by $107.2 million or 41.7 percent, from $257.2 million in the first three months of 2014, to $150.1 million in the first three months of 2015.

Energy Cost

- **Total Energy Costs.** Total energy costs increased by $243.9 million or 47.3 percent, from -$515.3 million in the first three months of 2014 to -$271.5 million in the first three months of 2015.
- **Day-Ahead Energy Costs.** Day-ahead energy costs increased by $357.8 million or 53.3 percent, from -$670.9 million in the first three months of 2014 to -$313.1 million in the first three months of 2015.
- **Balancing Energy Costs.** Balancing energy costs decreased by $123.4 million or 76.0 percent, from $162.4 million in the first three months of 2014 to $39.0 million in the first three months of 2015.
- **Monthly Total Energy Costs.** Monthly total energy costs in the first three months of 2015 ranged from -$141.5 million in February to -$59.5 million in March.

Section 11 Conclusion

Congestion reflects the underlying characteristics of the power system, including the nature and capability of transmission facilities, the offers and geographic distribution of generation facilities, the level and geographic distribution of incremental bids and offers and the geographic and temporal distribution of load.

ARRs and FTRs served as an effective, but not total, offset to congestion. ARR and FTR revenues offset 88.5 percent of the total congestion costs including the Day-Ahead Energy Market and the balancing energy market in PJM for the first ten months of the 2014 to 2015 planning period. In the 2013 to 2014 planning period, total ARR and FTR revenues offset 98.2 percent of the congestion costs.

Overview: Section 12, "Planning"

Planned Generation and Retirements

- **Planned Generation.** As of March 31, 2015, 67,268.0 MW of capacity were in generation request queues for construction through 2024, compared to an average installed capacity of 200,808.1 MW as of March 31, 2015. Of the capacity in queues, 8,703.1 MW, or 12.9 percent, are uprates and the rest are new generation. Wind projects account for 15,216.0 MW of nameplate capacity or 22.6 percent of the capacity in the queues. Combined-cycle projects account for 40,933.4 MW of capacity or 60.9 percent of the capacity in the queues.
- **Generation Retirements.** As shown in Table 12-6, 26,787.8 MW have been, or are planned to be, retired between 2011 and 2019, with all but 2,924.8 MW planned to be retired by the end of 2015. The AEP Zone accounts for 6,024.0 MW, or 22.5 percent, of all MW planned for retirement from 2015 through 2019.
- **Generation Mix.** A significant change in the distribution of unit types within the PJM footprint is likely as natural gas fired units continue to be developed and steam units continue to be retired. While only 1,992.5 MW of coal fired steam capacity are currently in the queue, 9,343.8 MW of coal fired steam capacity are slated for deactivation. Most of these retirements, 7,692.8 MW, are scheduled to take place by June 1, 2015, in large part due to the EPA's Mercury and Air Toxics Standards (MATS). In contrast, 43,479.3 MW of gas fired capacity are in the queue, while only 1,572.0 MW of natural gas units are planned to retire. The replacement of coal steam units by units burning natural gas could significantly affect future congestion, the role of firm and interruptible gas supply, and natural gas supply infrastructure.

Generation and Transmission Interconnection Planning Process

- Any entity that requests interconnection of a new generating facility, including increases to the capacity of an existing generating unit, or that requests interconnection of a merchant transmission facility, must follow the process defined in the PJM tariff to obtain interconnection service.[131] The process is complex and time consuming as a result of the nature of the required analyses. The cost, time and uncertainty associated

131 PJM. OATT Parts IV & VI.

with interconnecting to the grid may create barriers to entry for potential entrants.

- The queue contains a substantial number of projects that are not likely to be built. These projects may create barriers to entry for projects that would otherwise be completed by taking up queue positions, increasing interconnection costs and creating uncertainty.
- Many feasibility, impact and facilities studies are delayed for reasons including disputes with developers, circuit and network issues, retooling as a result of projects being withdrawn, and an accumulated backlog of incomplete studies.
- Where the transmission owner is a vertically integrated company that also owns generation, there is a potential conflict of interest when the transmission owner evaluates the interconnection requirements of new generation which is a competitor to the generation of the parent company of the transmission owner. There is also a potential conflict of interest when the transmission owner evaluates the interconnection requirements of new generation which is part of the same company as the transmission owner.

Regional Transmission Expansion Plan (RTEP)

- Artificial Island is an area in southern New Jersey that includes nuclear units at Salem and at Hope Creek. On April 29, 2013, PJM issued a request for proposal (RFP), seeking technical solutions to improve stability issues, operational performance under a range of anticipated system conditions, and the elimination of potential planning criteria violations in this area. PJM received 26 individual proposals from seven entities, including proposals from the incumbent transmission owner, PSE&G, and from non-incumbents. PJM staff announced on April 28, 2015, that they will recommend that the Board approve the Artificial Island project being designated to LS Power, PSE&G, and PHI with a total cost estimate between $263M and $283M.

Backbone Facilities

- PJM baseline transmission projects are implemented to resolve reliability criteria violations. PJM backbone transmission projects are a subset of significant baseline projects intended to resolve a wide range of reliability criteria violations and congestion issues and which have substantial impacts on energy and capacity markets. The current backbone projects are Mount Storm-Doubs, Jacks Mountain, Susquehanna-Roseland, and Surry Skiffes Creek 500kV.

Transmission Facility Outages

- PJM maintains a list of reportable transmission facilities. When the reportable transmission facilities need to be taken out of service, PJM transmission owners are required to report planned transmission facility outages as early as possible. PJM processes the transmission facility outages according to rules in PJM's Manual 3 to decide if the outage is on time, late, or past its deadline.[132]

Section 12 Recommendations

The MMU recommends improvements to the planning process.

- The MMU recommends the creation of a mechanism to permit a direct comparison, or competition, between transmission and generation alternatives, including which alternative is less costly and who bears the risks associated with each alternative. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that rules be implemented to permit competition to provide financing for transmission projects. This competition could reduce the cost of capital for transmission projects and significantly reduce total costs to customers. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that the question of whether Capacity Injection Rights (CIRs) should persist after the retirement of a unit be addressed. Even if the treatment of CIRs remains unchanged, the rules need to ensure

132 PJM. "Manual 03: Transmission Operations," Revision 46 (December 1, 2014), Section 4.

that incumbents cannot exploit control of CIRs to block or postpone entry of competitors.[133] (Priority: Low. First reported 2013. Status: Not adopted.)

- The MMU recommends outsourcing interconnection studies to an independent party to avoid potential conflicts of interest. Currently, these studies are performed by incumbent transmission owners under PJM's direction. This creates potential conflicts of interest, particularly when transmission owners are vertically integrated and the owner of transmission also owns generation. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends improvements in queue management including that PJM establish a review process to ensure that projects are removed from the queue if they are not viable, as well as a process to allow commercially viable projects to advance in the queue ahead of projects which have failed to make progress, subject to rules to prevent gaming. (Priority: Medium. First reported 2013. Status: Not Adopted.)
- The MMU recommends an analysis of the study phase of PJM's transmission planning to reduce the need for postponements of study results, to decrease study completion times, and to improve the likelihood that a project at a given phase in the study process will successfully go into service. (Priority: Medium. First reported Q1, 2014. Status: Partially adopted, 2014.)
- The MMU recommends that PJM establish fair terms of access to rights of way and property, such as at substations, in order to permit competition between incumbent transmission providers and nonincumbent providers. (Priority: Medium. First reported 2014. Status: Not adopted.)
- The MMU recommends that PJM reevaluate transmission outage tickets when the outage is rescheduled. (Priority: Low. First reported 2014. Status: Not adopted.)

133 See "Comments of the Independent Market Monitor for PJM," <http://www.monitoringanalytics.com/reports/Reports/2012/IMM_Comments_ER12-1177-000_20120312.pdf>.

Section 12 Conclusion

The goal of PJM market design should be to enhance competition and to ensure that competition is the driver for all the key elements of PJM markets. But transmission investments have not been fully incorporated into competitive markets. The construction of new transmission facilities has significant impacts on the energy and capacity markets. But when generating units retire or load increases, there is no market mechanism in place that would require direct competition between transmission and generation to meet loads in the affected area. In addition, despite Order No. 1000, there is not yet a robust and clearly defined mechanism to permit competition to build transmission projects or to obtain least cost financing through the capital markets.

The addition of a planned transmission project changes the parameters of the capacity auction for the area, changes the amount of capacity needed in the area, changes the capacity market supply and demand fundamentals in the area and may effectively forestall the ability of generation to compete. But there is no mechanism to permit a direct comparison, let alone competition, between transmission and generation alternatives. There is no mechanism to evaluate whether the generation or transmission alternative is less costly or who bears the risks associated with each alternative. Creating such a mechanism should be an explicit goal of PJM market design.

The PJM queue evaluation process should be improved to ensure that barriers to competition are not created. Issues that need to be addressed include the ownership rights to CIRs, whether transmission owners should perform interconnection studies, and improvements in queue management.

The PJM rules for competitive transmission development should build upon Order No. 1000 to create real competition between incumbent transmission providers and nonincumbent providers. One way to do this is to consider utilities' ownership of property and rights of way at or around transmission substations. In many cases, the land acquired included property intended to support future expansion of the grid. Incumbents have included the costs of the property in their rate base. Because PJM now has the responsibility for planning the development of the grid under its RTEP process, property bought to facilitate future expansion should be a part of that process and be made available to all providers on equal terms.

Overview: Section 13, "FTR and ARRs"

Financial Transmission Rights

Market Structure

- **Supply.** Market participants can sell FTRs. In the Monthly Balance of Planning Period FTR Auctions for the first ten months of the 2014 to 2015 planning period, total participant FTR sell offers were 3,230,754 MW, down from 4,990,310 MW for the same period during the 2013 to 2014 planning period.
- **Demand.** The total FTR buy bids from the Monthly Balance of Planning Period FTR Auctions for the first ten months of the 2014 to 2015 planning period increased 2.2 percent from 22,593,835 MW for the same time period of the prior planning period, to 23,099,689 MW.
- **Patterns of Ownership.** For the Monthly Balance of Planning Period Auctions, financial entities purchased 77.5 percent of prevailing flow and 87.2 percent of counter flow FTRs for January through March of 2015. Financial entities owned 70.0 percent of all prevailing and counter flow FTRs, including 61.3 percent of all prevailing flow FTRs and 83.8 percent of all counter flow FTRs during the period from January through March 2015.

Market Behavior

- **FTR Forfeitures.** Total forfeitures for the first ten months of the 2014 to 2015 planning period were $3.3 million for Increment Offers, Decrement Bids and UTC Transactions.
- **Credit Issues.** No defaults occurred in the first three months of 2015.

Market Performance

- **Volume.** For the first ten months of the 2014 to 2015 planning period Monthly Balance of Planning Period FTR Auctions 2,032,310 MW MW (8.8 percent) of FTR buy bids and 710,740 MW (22.0 percent) of FTR sell offers cleared.
- **Price.** The weighted-average buy-bid cleared FTR price in the Monthly Balance of Planning Period FTR Auctions for the 2014 to 2015 planning period was $0.18, up from $0.08 per MW in the 2013 to 2014 planning period.
- **Revenue.** The Monthly Balance of Planning Period FTR Auctions generated $17.3 million in net revenue for all FTRs for the first ten months of the 2014 to 2015 planning period, up from $8.3 million for the same time period in the 2013 to 2014 planning period.
- **Revenue Adequacy.** FTRs were paid at 100 percent of the target allocation level for the first ten months of the 2014 to 2015 planning period. This high level of revenue adequacy was primarily due to the significant reduction in the allocation of Stage 1B and Stage 2 ARRs as a result of PJM's implementation of more conservative outage assumptions and additional constraints (closed loop interfaces) in the FTR auction model.
- **ARR and FTR Offset.** ARRs and FTRs served as an effective, but not total, offset to congestion. ARR and FTR revenues offset 88.5 percent of the total congestion costs including the Day-Ahead Energy Market and the balancing energy market in PJM for the first ten months of the 2014 to 2015 planning period. In the 2013 to 2014 planning period, total ARR and FTR revenues offset 98.2 percent of the congestion costs.
- **Profitability.** FTR profitability is the difference between the revenue received for an FTR and the cost of the FTR. In 2015, FTRs were profitable overall, with $255.2 million in profits for physical entities, of which $160.3 million was from self-scheduled FTRs, and $171.2 million for financial entities.

Auction Revenue Rights

Market Structure

- **ARR Allocations.** Due to more conservative treatment of transmission outages in the FTR Auction model by PJM, designed to reduce revenue inadequacy, ARR allocation quantities were significantly reduced. For the 2014 to 2015 planning period, Stage 1B and Stage 2 ARR allocations were reduced 84.9 percent and 88.1 percent from the 2013 to 2014 planning period.

- **Residual ARRs.** If ARR allocations are reduced as the result of a modeled transmission outage and the transmission outage ends during the relevant planning year, the result is that residual ARRs may be available. These residual ARRs are automatically assigned to eligible participants the month before the effective date. Residual ARRs are only available on paths prorated in Stage 1 of the annual ARR allocation, only effective for single, whole months and cannot be self scheduled. Residual ARR clearing prices are based on monthly FTR auction clearing prices.

  In the first ten months of the 2014 to 2015 planning period planning period, PJM allocated a total of 19,928 MW of residual ARRs, up from 10,956.2 MW in the first ten months of the 2013 to 2014 planning period, with a total target allocation of $1.3 million for the first three months of 2015, down from $1.8 million for the first three months in 2014. This 81.9 percent increase in volume was primarily a result of the significant reductions in Annual ARR Stage 1B allocations.

- **ARR Reassignment for Retail Load Switching.** There were 64,086 MW of ARRs associated with $338,100 of revenue that were reassigned in the 2013 to 2014 planning period. There were 53,270 MW of ARRs associated with $456,100 of revenue that were reassigned for the first ten months of the 2014 to 2015 planning period.

Market Performance

- **Revenue Adequacy.** For the first ten months of the 2014 to 2015 planning period, the ARR target allocations, which are based on the nodal price differences from the Annual FTR Auction, were $735.0 million while PJM collected $765.9 million from the combined Long Term, Annual and Monthly Balance of Planning Period FTR Auctions, making ARRs revenue adequate. For the 2013 to 2014 planning period, the ARR target allocations were $506.2 million while PJM collected $568.8 million from the combined Long Term, Annual and Monthly Balance of Planning Period FTR Auctions, making ARRs revenue adequate.

- **ARRs as an Offset to Congestion.** ARRs served as an effective offset against congestion. The total revenues received by ARR holders, including self-scheduled FTRs, offset 100 percent of the total congestion costs experienced by ARR holders across the Day-Ahead Energy Market and balancing energy market for the first ten months of the 2014 to 2015 planning period and for the 2013 to 2014 planning period. Individual participants may not have a 100 percent offset.

Section 13 Recommendations

- The MMU recommends that PJM report correct monthly payout ratios to reduce understatement of payout ratios on a monthly basis. (Priority: Low. First reported 2013. Status: Not adopted. Stakeholder process.)
- The MMU recommends that PJM eliminate portfolio netting to eliminate cross subsidies among FTR marketplace participants. (Priority: High. First reported 2013. Status: Not adopted. Stakeholder process.)
- The MMU recommends that PJM eliminate subsidies to counter flow FTRs by applying the payout ratio to counter flow FTRs in the same way the payout ratio is applied to prevailing flow FTRs. (Priority: High. First reported 2013. Status: Not adopted. Stakeholder process.)
- The MMU recommends that PJM eliminate geographic cross subsidies. (Priority: High. First reported 2013. Status: Not adopted. Stakeholder process.)
- The MMU recommends that PJM improve transmission outage modeling in the FTR auction models. (Priority: Low. First reported 2013. Status: Adopted partially, 14/15 planning period. Stakeholder process.)
- The MMU recommends that PJM reduce FTR sales on paths with persistent overallocation of FTRs including clear rules for what defines persistent overallocation and how the reduction will be applied. (Priority: High. First reported 2013. Status: Adopted partially, 14/15 planning period.)

- The MMU recommends that PJM implement a seasonal ARR and FTR allocation system to better represent outages. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM eliminate overallocation requirement of ARRs in the Annual ARR Allocation process. (Priority: High. First reported 2013. Status: Not adopted. Stakeholder process.)
- The MMU recommends that PJM apply the FTR forfeiture rule to up to congestion transactions consistent with the application of the FTR forfeiture rule to increment offers and decrement bids. (Priority: High. First reported 2013. Status: Not adopted. Pending before FERC.)
- The MMU recommends that PJM not use the ATSI Interface or create similar closed loop interfaces to set zonal prices to accommodate the inadequacies of the demand side resource capacity product. Market prices should be a function of market fundamentals. The MMU recommends that, in general, the implementation of closed loop interface constraints be studied in advance and, if there is good reason to implement, implemented so as to include them in the FTR Auction model to minimize their impact on FTR funding. (Priority: Medium. First reported 2013. Status: Not adopted.)

Section 13 Conclusion

The annual ARR allocation provides firm transmission service customers with the financial equivalent of physically firm transmission service, without requiring physical transmission rights that are difficult to define and enforce. The fixed charges paid for firm transmission services result in the transmission system which provides physically firm transmission service.

After the introduction of LMP markets, financial transmission rights (FTRs) permitted the loads which pay for the transmission system to continue to receive those benefits in the form of revenues which offset congestion to the extent permitted by the transmission system. Financial transmission rights and the associated revenues were directly provided to loads in recognition of the facts that loads pay for the transmission system which permits low cost generation to be delivered to load. Another way of describing the result is that FTRs and the associated revenues were directly provided to loads in recognition of the fact that load pays locational prices which result in load payments in excess of generation revenues which are the source of the funds available to offset congestion costs in an LMP market. In other words, load payments in excess of generation revenues are the source of the funds to pay FTRs. In an LMP system, the only way to ensure that load receives the benefits associated with the use of the transmission system to deliver low cost energy is to use FTRs to pay back to load the difference between the total load payments and the total generation revenues associated with congestion.

With the creation of ARRs, FTRs no longer serve their original function of providing firm transmission customers with the financial equivalent of physically firm transmission service. FTR holders, with the creation of ARRs, do not have the right to financially firm transmission service and FTR holders do not have the right to revenue adequacy.

For these reasons, load should never be required to subsidize payments to FTR holders, regardless of the reason. Such subsidies have been suggested repeatedly.[134] One form of recommended subsidies would ignore balancing congestion when calculating total congestion dollars available to fund FTRs. This approach would ignore the fact that loads must pay both day ahead and balancing congestion. To eliminate balancing congestion from the FTR revenue calculation would require load to pay twice for congestion. Load would have to continue paying for the physical transmission system, would have to continue paying in excess of generator revenues and not have balancing congestion included in the calculation of congestion in order to increase the payout to holders of FTRs who are not loads and who therefore did not receive an allocation of ARRs. In other words, load would have to continue providing all the funding of FTRs, while payments to FTR holders who did not receive ARRs exceed total congestion on their FTR paths.

Revenue adequacy has received a lot of attention in the PJM FTR Market. There are several factors that can affect the reporting, distribution of and

134 See "FirstEnergy Solutions Corp. Allegheny Energy Supply Company, LLC v PJM Interconnection, LLC," Docket No. EL13-47-000 (February 15, 2013).

quantity of funding in the FTR Market. Revenue adequacy is misunderstood. FTR holders, with the creation of ARRs, do not have the right to financially firm transmission service and FTR holders do not have the right to revenue adequacy. ARR holders do have those rights based on their payment for the transmission system. FTR holders appropriately receive revenues based on actual congestion in both day-ahead and balancing markets. When day-ahead congestion differs significantly from real-time congestion, as has occurred only recently, this is evidence that there are reporting issues, cross subsidization issues, issues with the level of FTRs sold, and issues with modeling differences between the day-ahead and real-time. Such differences are not an indication that FTR holders are being underallocated total congestion dollars.

Reported FTR revenue adequacy uses target allocations as the relevant benchmark. But target allocations are not the relevant benchmark. Target allocations are based on day-ahead congestion only, ignoring the other part of total congestion which is balancing congestion. The difference between the congestion payout using total congestion and the congestion payout using only day-ahead congestion illustrates the issue. For 2014, total day-ahead congestion was $2,218.4 million while total day-ahead plus balancing congestion was $1,919.3 million, compared to target allocations of $2,419.4 million in the same time period.

Clearing prices fell and cleared quantities increased from the 2010 to 2011 planning period through the 2013 to 2014 planning period. The market response to lower revenue adequacy was to reduce bid prices and to increase bid volumes and offer volumes.

PJM used a more conservative approach to modeling the transmission capability for the 2014 to 2015 planning period. The result was a significant reduction in Stage 1B and Stage 2 ARR allocations and a corresponding reduction in the available quantity of FTRs, an increase in FTR prices and an increase in ARR target allocations. The market response to the reduced supply of FTRs was increased bid prices, increased clearing prices and reduced clearing quantities.

The monthly payout ratio reported by PJM is understated. The PJM reported monthly payout ratio does not appropriately consider negative target allocations as a source of revenue to fund FTRs on a monthly basis. PJM's reported monthly payout ratios are based on an estimate of the results for the entire year. The reported monthly payout ratio should be the actual monthly results including all revenue. The MMU recommends that the calculation of the monthly FTR payout ratio appropriately include negative target allocations as a source of revenue, consistent with actual settlement payout.

FTR target allocations are currently netted within each organization in each hour. This means that within an hour, positive and negative target allocations within an organization's portfolio are offset prior to the application of the payout ratio to the positive target allocation FTRs. The payout ratios are also calculated based on these net FTR positions. The current method requires those participants with fewer negative target allocation FTRs to subsidize those with more negative target allocation FTRs. The current method treats a positive target allocation FTR differently depending on the portfolio of which it is a part. The correct method would treat all FTRs with positive target allocations exactly the same, which would eliminate this form of cross subsidy. This should also be extended to include the end of planning period FTR uplift calculation. The net of a participant's portfolio should not determine their FTR uplift liability, rather their portion of total positive target allocations should be used to determine a participant's uplift charge. The FTR market cannot work efficiently if FTR buyers do not receive payments consistent with the performance of their FTRs. Eliminating the portfolio subsidy would be a good first step in that direction.

If netting within portfolios were eliminated and the payout ratio were calculated correctly, the payout ratio in the 2013 to 2014 planning period would have been 87.5 percent instead of the reported 72.8 percent. The MMU recommends that netting of positive and negative target allocations within portfolios be eliminated.

The current rules create an asymmetry between the treatment of counter flow and prevailing flow FTRs. Counter flow FTR holders make payments over the planning period, in the form of negative target allocations. These negative target allocations are paid at 100 percent regardless of whether positive target allocation FTRs are paid at less than 100 percent.

There is no reason to treat counter flow FTRs more favorably than prevailing flow FTRs. Counter flow FTRs should also be affected when the payout ratio is less than 100 percent. This would mean that counter flow FTRs would pay back an increased amount that mirrors the decreased payments to prevailing flow FTRs. The adjusted payout ratio would evenly divide the impact of lower payouts among counter flow FTR holders and prevailing flow FTR holders by increasing negative counter flow target allocations by the same amount it decreases positive target allocations. The FTR market cannot work efficiently if FTR buyers do not receive payments consistent with the performance of their FTRs. Eliminating the counter flow subsidy would be another good step in that direction.

The result of removing portfolio netting and applying a payout ratio to counter flow FTRs would have increased the calculated payout ratio in the 2013 to 2014 planning period from the reported 72.8 percent to 91.0 percent. The MMU recommends that counter flow and prevailing flow FTRs should be treated symmetrically with respect to the application of a payout ratio.

The overallocation of Stage 1A ARRs results in FTR overallocations on the same facilities. Stage 1A ARR overallocation is a source of revenue inadequacy and cross subsidy. While prorating the Stage 1A ARR allocations based on actual system capability would address the issue, Stage 1A ARRs cannot be prorated under current market rules.

The MMU recommends that Stage 1A allocations be prorated to match actual system capability and that PJM commit to building the transmission capability required to provide all defined Stage 1A allocations. If Stage 1A overallocations are addressed, Stage 1B and Stage 2 allocations would not need to be reduced as they were for the 2014 to 2015 planning period.

The result of removing portfolio netting, applying a payout ratio to counter flow FTRs and eliminating Stage 1A ARR overallocation in the 2013 to 2014 planning period would have increased the payout ratio to 94.6 percent without reducing ARR allocations in Stage 1B and Stage 2.

In addition to addressing these issues, the approach to the question of FTR funding should also look at the fundamental reasons that there has been a significant and persistent difference between day-ahead and balancing congestion. These reasons include the inadequate transmission outage modeling in the FTR auction model which ignores all but long term outages known in advance; the different approach to transmission line ratings in the day-ahead and real-time markets, including reactive interfaces, which directly results in differences in congestion between day-ahead and real-time markets; differences in day-ahead and real-time modeling including the treatment of loop flows, the treatment of outages, the modeling of PARs and the nodal location of load, which directly results in differences in congestion between day-ahead and real-time markets; the overallocation of ARRs which directly results in a difference between congestion revenue and the payment obligation; the appropriateness of seasonal ARR allocations to better match actual market conditions with the FTR auction model; geographic subsidies from the holders of positively valued FTRs in some locations to the holders of consistently negatively valued FTRs in other locations; the contribution of up-to congestion transactions to the differences between day-ahead and balancing congestion and thus to FTR payout ratios; and the continued sale of FTR capability on pathways with a persistent difference between FTRs and total congestion revenue. The MMU recommends that these issues be reviewed and modifications implemented. Regardless of how these issues are addressed, funding issues that persist as a result of modeling differences and flaws in the design of the FTR market should be borne by FTR holders operating in the voluntary FTR market and not imposed on load through the mechanism of balancing congestion.