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State of the Market Report for PJM

Monitoring Analytics, LLC

Independent
Market Monitor
for PJM

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2014

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 *2014 Quarterly State of the Market Report for PJM: January through March*.

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).

Introduction

Q1 2014 in Review

The state of the PJM markets in the first three months of 2014 reflected the extreme winter weather conditions, and the resultant stress on the markets revealed the fundamental strength of the markets as well as areas that need improvement. The results of the energy market, the results of the capacity market and the results of the regulation market were competitive.

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 still 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 operating at, or close to, their marginal costs, although this was not always the case during the high demand hours in January. The performance of the PJM markets under scarcity 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. This is evidence of generally competitive behavior, although the behavior of some participants during the high demand periods in January raises concerns about economic withholding. 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.

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. Cost of service regulation is tempting because guaranteed rates of return and fixed prices may look attractive to both asset owners in uncertain markets and to customers paying higher prices after a period of extremely low prices 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 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. The impact of continued inclusion of the limited DR product in the capacity market was about $4.6 billion in the 2016/2017 base auction. The impact of the inclusion of imports that did not have firm transmission at the time of the auction was about $1.3 billion. The impact of the 2.5 percent offset was about $1.4 billion. The total value of capacity sold in the 2016/2017 base auction was $5.5 billion based on actual clearing prices and quantities.

These market design choices have substantial impacts. This price suppression has had and continues to have an impact on retirement decisions and on decisions to invest in new resources. Premature and uneconomic retirements and the failure to make economic investments in new entry are both the results. No discussion of reliability or of resource diversity can ignore the impacts of this price suppression.

The most fundamental required change to the capacity market design is the enforcement of a consistent definition of a capacity resource so that all capacity resources are full substitutes for one another. In the case of imports, substitutability means that the units must have a pseudo tie into PJM. Without that, capacity imports cannot be substitutes for internal capacity. As a result of the fact that all imports are included in the rest of RTO, the inadequate definition of imports has had a larger impact on western zones. In the case of demand resources, substitutability means that resources must have a day-ahead energy market must offer requirement and must be subject to the same offer cap as all other resources and must be an annual product with obligations in the winter as well as the summer.

An essential part of being full substitutes is the requirement that all capacity resources be physical resources. The requirement to be a physical resource should apply at the time of auctions and should also constitute a binding 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. Under existing capacity market rules, capacity imports, planned new generation and demand resources all face incentives to buy out of their positions in incremental auctions and do so.

The extreme winter weather revealed the real meaning of being a capacity resource. Capacity resources are, by clearing the capacity market, obligated to make offers in the day-ahead energy market. This obligation exists regardless of whether gas procurement is difficult, regardless of whether gas prices are high and regardless of whether gas procurement is risky. The winter weather also further revealed the problems with treating limited DR as a substitute for annual resources. Although some limited DR did respond, the question should be, how did the performance of limited DR compare to the performance of the coal units or the combined cycle units that were displaced by DR.

The behavior of some generation owners during the extreme weather made issues related to the incentives in the capacity market much more urgent. The incentives in the capacity market are inadequate and the very high outage rates in January are evidence of that. At present only half of capacity market revenues are at risk for failure to perform on high demand days. Gas-fired units with a single fuel are exempt from any capacity market revenue impact that results from lack of fuel outages on high demand days. The incentives in the capacity market should be equivalent to the incentives in an all energy market with scarcity pricing. An increase in capacity market prices must be accompanied by a strengthening of capacity market incentives so that customers can be assured of getting what they pay for.

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. 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.

The PJM markets and PJM market participants from all sectors face significant challenges, some of which were clearly revealed in January. PJM and its market participants will need to continue to work constructively to address these challenges to ensure the continued effectiveness of PJM markets.

PJM Market Summary Statistics

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

Table 1-1 PJM Market Summary Statistics, January through March, 2013 and 2014[1]

	2013 (Jan - Mar)	2014 (Jan - Mar)
Load	199,567 GWh	214,951 GWh
Generation	202,674 GWh	219,999 GWh
Imports (+) / Exports (-)	1,098 GWh	(243)GWh
Losses	4,705 GWh	5,352 GWh
Regulation Requirement*	707 MW	664 MW
RTO Primary Reserve Requirement **	NA	2,066 MW
Total Billing	$7.76 Billion	$21.07 Billion
Peak	Jan 22, 2013 19:00	Jan 7, 2014 19:00
Peak Load	126,632 MW	140,467 MW
Load Factor	0.72	0.71
Installed Capacity	As of 03/31/2013	As of 03/31/2014
Installed Capacity	181,896 MW	182,894 MW

* Hourly average. Amounts shown are stated in Effective MW.

** Regulatory requirement remained 2,063 MW throughout the year. Amount shown is daily average.

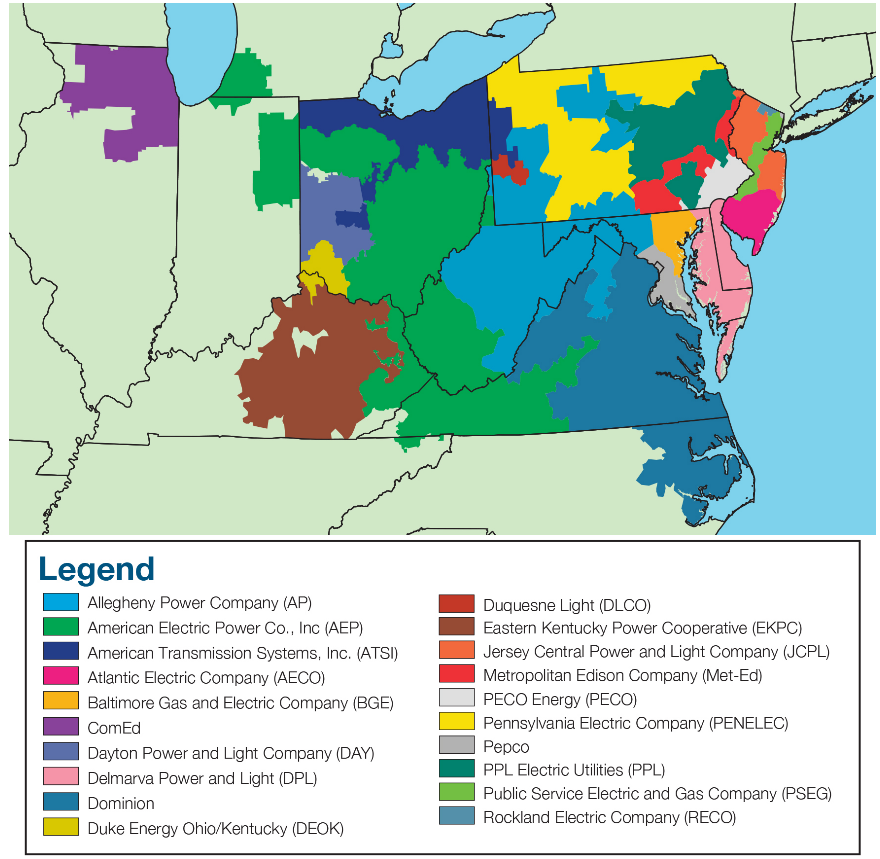
PJM Market Background

The PJM Interconnection, L.L.C. (PJM) operates a centrally dispatched, competitive wholesale electric power market that, as of March 31, 2014, had installed generating capacity of 182,894 megawatts (MW) and 876 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).[2,3,4]

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.

1 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."
2 See PJM's "Member List," which can be accessed at: <http://pjm.com/about-pjm/member-services/member-list.aspx>.
3 See PJM's "Who We Are," which can be accessed at: <http://pjm.com/about-pjm/who-we-are.aspx>.
4 See the *2013 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.

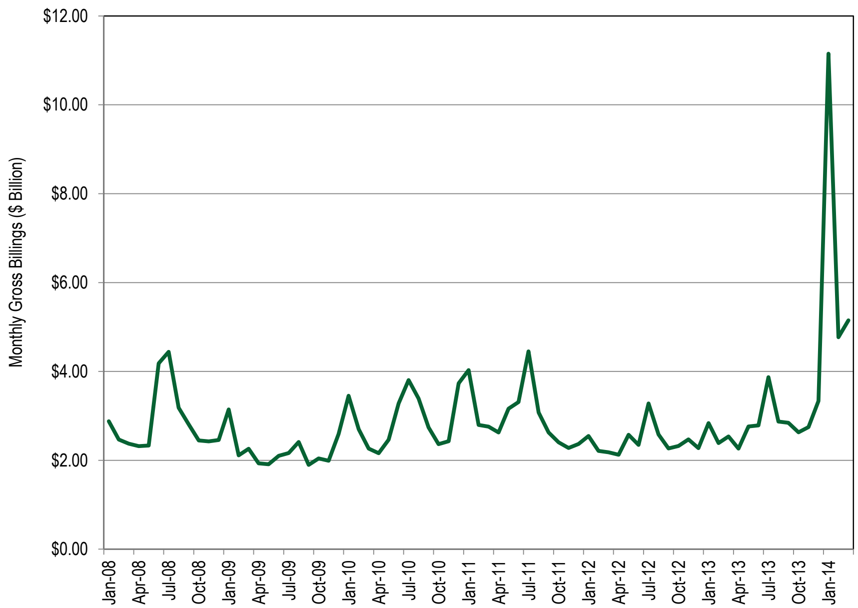
Figure 1-1 PJM's footprint and its 20 control zones



As shown in Figure 1-2, in the first three months of 2014, PJM had total billings of $21.07 billion, up from $7.76 billion in the first three months of 2013.[5] The increase in billings in January 2014 derived from high demand and high prices that resulted from extreme cold weather. The impact of the extreme weather in January is addressed throughout this quarterly report. In February and March, cold weather continued, and billing rates continued above the highest monthly billing rates prior to 2014.

5 Monthly billing values are provided by PJM.

Figure 1-2 PJM reported monthly billings ($ Billions): January 2008 through March 2014



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 spinning reserve on December 1, 2002. PJM introduced an Auction Revenue Rights (ARR) allocation process and an associated Annual FTR Auction effective June 1, 2003. PJM introduced the RPM Capacity Market effective June 1, 2007. PJM implemented the DASR Market on June 1, 2008.[6,7]

On June 1, 2013, PJM integrated the Eastern Kentucky Power Cooperative (EKPC).

Conclusions

This report assesses the competitiveness of the markets managed by PJM in the first three months of 2014, 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, 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 ownership among multiple entities and the market demand and it does

6 See also the *2013 State of the Market Report for PJM*, Volume II, Appendix B, "PJM Market Milestones."

7 Analysis of 2013 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 *2013 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography."

so using actual market conditions reflecting both temporal and geographic granularity. Market shares and the related Herfindahl-Hirschman Index (HHI) are also measures of market structure.

Participant behavior refers to the actions of individual market participants, also sometimes referenced 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 performance, 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 the following for the first three months of 2014:

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 during the first three months of 2014 was moderately concentrated. Based on the hourly Energy Market measure, average HHI was 1133 with a minimum of 956 and a maximum of 1378 in the first three months of 2014.
- 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 the high demand periods in January 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.
- Market design was evaluated as effective because the analysis shows that the PJM Energy Market resulted in competitive market outcomes, with prices reflecting, on average, the marginal cost to produce energy. 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 expanding 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.[8] 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.[9] 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.

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.[10]
- 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.[11]
- 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 and the inclusion of imports which are not substitutes for internal capacity resources.

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**

- 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 2014.
- Participant behavior in the Regulation Market was evaluated as competitive for the first three months of 2014 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.

8 OATT Attachment M.
9 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.
10 In the 2008/2009 RPM Third Incremental Auction, 18 participants in the RTO market passed the TPS test.
11 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..

Table 1-5 The 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 the 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, 12 percent 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 over sells FTRs. FTR funding levels are reduced as a result of these and other factors.

Role of MMU

The FERC assigns three core functions to MMUs: reporting, monitoring and market design.[12] 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.[13]

Reporting

The MMU performs its reporting function primarily by issuing and filing annual and quarterly state of the market reports, and reports on market issues. 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.

The MMU also issues reports on specific topics in depth. The MMU regularly issues reports on RPM auctions. In other ad hoc reports, the MMU responds to the needs of FERC, state regulators, or other authorities, in order to assist policy development, decision making in regulatory proceedings, and in support of investigations.

12 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).

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

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.[14] The MMU has direct, confidential access to the FERC.[15] The MMU may also refer matters to the attention of state commissions.[16]

The MMU monitors market behavior for violations of FERC Market Rules.[17] 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…"[18,19] The MMU also monitors PJM for compliance with the rules, in addition to market participants.[20]

The MMU has no prosecutorial or enforcement authority. The MMU notifies the FERC when it identifies a significant market problem or market violation.[21] 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.[22] [23] 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

14 OATT Attachment M § IV.

15 OATT Attachment M § IV.K.3.

16 OATT Attachment M § IV.H.

17 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.")

18 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.

19 OATT Attachment M § II(h-1).

20 OATT Attachment M § IV.C.

21 OATT Attachment M § IV.I.1.

22 *Id.*

23 *Id.*

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.

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. 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.[31] 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.

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.[32] The MMU initiates and proposes changes to the design of such markets or the PJM Market Rules in stakeholder or regulatory proceedings.[33] 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.[34] 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.[35] The MMU may provide in its annual, quarterly and other reports "recommendations regarding any matter within its purview."[36]

Prioritized Summary of New Recommendations

Table 1-8 includes a brief description and a priority ranking of the MMU's new recommendations for this quarterly report.

Priority rankings are relative. The creation of rankings recognizes that there are limited resources available to address market issues and that problems must be ranked in order to determine the order in which to address them. It does not mean that all the problems should not be addressed. Priority rankings are dynamic and as new issues are identified, priority rankings will change. The rankings reflect a number of factors including the significance

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 Attachment M § IV.D.
33 *Id.*
34 *Id.*
35 *Id.*
36 OATT Attachment M § VI.A.

of the issue for efficient markets, the difficulty of completion and the degree to which items are already in progress. A low ranking does not necessarily mean that an issue is not important, but could mean that the issue would be easy to resolve.

There are three priority rankings: High, Medium and Low. High priority indicates that the recommendation requires action because it addresses a market design issue that creates significant market inefficiencies and/or long lasting negative market effects. Medium priority indicates that the recommendation addresses a market design issue that creates intermediate market inefficiencies and/or near term negative market effects. Low priority indicates that the recommendation addresses a market design issue that creates smaller market inefficiencies and/or more limited market effects.

Table 1-8 Prioritized summary of new recommendations: January through March, 2014

Priority	Section	Description
Medium	3 – Energy Market	Implement detailed rules covering the purchase of emergency energy, recalling energy exports from PJM capacity resources and prohibiting new energy exports from PJM capacity resources.
Low	3 – Energy Market	Explain how LMPs are calculated when demand response is marginal.
Low	10 – Ancillary Services	Study September 2013 and January 2014 secondary reserve events and evaluate replacing DASR with secondary reserve.
Medium	12 - Planning	Streamline the transmission planning study phase.

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 2013 and the first three months of 2014.

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 94.6 percent of the total price per MWh in the three months of 2014.

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.[37]
- The Energy Uplift (Operating Reserves) component is the average price per MWh of day-ahead, balancing and synchronous condensing charges.[38]
- The Reactive component is the average cost per MWh of reactive supply and voltage control from generation and other sources.[39]
- The Regulation component is the average cost per MWh of regulation procured through the Regulation Market.[40]
- 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.[41]

37 OATT §§ 13.7, 14.5, 27A & 34.
38 OA Schedules 1 §§ 3.2.3 & 3.3.3.
39 OATT Schedule 2 and OA Schedule 1 § 3.2.3B. The line item in Table 1-9 includes all reactive services charges.
40 OA Schedules 1 §§ 3.2.2, 3.2.2A, 3.3.2, & 3.3.2A; OATT Schedule 3.
41 OATT Schedule 12.

- 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.[42]
- The Emergency Load Response component is the average cost per MWh of the PJM Emergency Load Response Program.[43]
- 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.[44]
- 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.[45]
- The Synchronized Reserve component is the average cost per MWh of synchronized reserve procured through the Synchronized Reserve Market.[46]
- The Black Start component is the average cost per MWh of black start service.[47]
- The RTO Startup and Expansion component is the average cost per MWh of charges to recover AEP, ComEd and DAY's integration expenses.[48]
- The NERC/RFC component is the average cost per MWh of NERC and RFC charges, plus any reconciliation charges.[49]
- The Economic Load Response component is the average cost per MWh of day ahead and real time economic load response program charges to LSEs.[50]
- The Transmission Facility Charges component is the average cost per MWh of Ramapo Phase Angle Regulators charges allocated to PJM Mid-Atlantic transmission owners.[51]
- The Non-Synchronized Reserve component is the average cost per MWh of non-synchronized reserve procured through the Non-Synchronized Reserve Market.[52]
- The Emergency Energy component is the average cost per MWh of emergency energy.[53]

Table 1-9 Total price per MWh by category: January through March, 2013[54] and 2014

Category	Jan-Mar 2013 $/MWh	Jan-Mar 2014 $/MWh	Percent Change Totals	Jan-Mar 2013 Percent of Total	Jan-Mar 2014 Percent of Total
Load Weighted Energy	$37.41	$92.98	148.5%	74.1%	82.6%
Capacity	$4.83	$7.77	60.8%	9.6%	6.9%
Transmission Service Charges	$4.69	$5.19	10.8%	9.3%	4.6%
Operating Reserves (Uplift)	$0.94	$3.55	277.8%	1.9%	3.1%
Regulation	$0.28	$0.63	125.8%	0.6%	0.6%
Synchronized Reserves	$0.04	$0.56	1,223.1%	0.1%	0.5%
PJM Administrative Fees	$0.45	$0.43	(5.7%)	0.9%	0.4%
Reactive	$0.63	$0.37	(41.9%)	1.2%	0.3%
Transmission Enhancement Cost Recovery	$0.40	$0.36	(11.3%)	0.8%	0.3%
Emergency Load Response	$0.00	$0.18	NA	0.0%	0.2%
Day Ahead Scheduling Reserve (DASR)	$0.00	$0.17	23,375.4%	0.0%	0.1%
Emergency Energy	$0.00	$0.13	NA	0.0%	0.1%
Transmission Owner (Schedule 1A)	$0.08	$0.09	10.1%	0.2%	0.1%
Capacity (FRR)	$0.16	$0.06	(61.7%)	0.3%	0.1%
Black Start	$0.14	$0.06	(58.5%)	0.3%	0.1%
Non-Synchronized Reserves	$0.00	$0.04	1,753.7%	0.0%	0.0%
Load Response	$0.01	$0.04	435.4%	0.0%	0.0%
NERC/RFC	$0.02	$0.02	4.5%	0.0%	0.0%
RTO Startup and Expansion	$0.01	$0.01	(7.1%)	0.0%	0.0%
Transmission Facility Charges	$0.40	$0.00	(99.5%)	0.8%	0.0%
Total	$50.49	$112.62	123.0%	100.0%	100.0%

42 Reliability Assurance Agreement Schedule 8.1.
43 OATT PJM Emergency Load Response Program.
44 OA Schedules 1 §§ 3.2.3A.01 & OATT Schedule 6.
45 OATT Schedule 1A.
46 OA Schedule 1 § 3.2.3A.01; PJM OATT Schedule 6.
47 OATT Schedule 6A. The line item in Table 1-9 includes all Energy Uplift (Operating Reserves) charges for Black Start.
48 OATT Attachments H-13, H-14 and H-15 and Schedule 13.
49 OATT Schedule 10-NERC and OATT Schedule 10-RFC.
50 OA Schedule 1 § 3.6.
51 OA Schedule 1 § 5.3b.
52 OA Schedule 1 § 3.2.3A.001.
53 OA Schedule 1 §3.2.6.
54 The 2013 total price per MWh is higher than previously reported due to the addition of the Capacity (FRR) component.

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 273 MW, or 0.2 percent, from 177,820 MW in the first three months of 2013 to 177,547 MW in the first three months of 2014.[55] In 2014, 271 MW of new capacity were added to PJM. This new generation was mostly offset by the deactivation of 4 units (208 MW) since January 1, 2014. The decrease in offered supply in the first three months of 2014 was in part a result of a 1,866 MW reduction in net capacity between April 2013 and March 2014.[56]

  PJM average real-time generation in the first three months of 2014 increased by 8.5 percent from the first three months of 2013, from 92,776 MW to 100,655 MW. The PJM average real-time generation in the first three months of 2014 would have increased by 7.7 percent from the first three months of 2013, from 92,776 MW to 99,875 MW, if the EKPC Transmission Zone had not been included.[57]

  PJM average day-ahead supply in the first three months of 2014, including INCs and up-to congestion transactions, increased by 14.3 percent from the first three months of 2013, from 147,246 MW to 168,373 MW. The PJM average day-ahead supply, including INCs and up-to congestion transactions, would have increased by 13.7 percent from the first three months of 2013, from 147,246 MW to 167,394 MW, if the EKPC Transmission Zone had not been included. The day-ahead supply growth was 68.2 percent higher than the real-time generation growth as a result of the continued growth of up-to congestion transactions.

- **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 2014, coal units provided 48.6 percent, nuclear units 31.6 percent and gas units 14.7 percent of total generation. Compared to the first three months of 2013, generation from coal units increased 18.6 percent, generation from nuclear units decreased 3.6 percent, and generation from gas units increased 5.8 percent.

- **Marginal Resources.** In the PJM Real-Time Energy Market, during the first three months of 2014, coal units were 46.9 percent and natural gas units were 42.9 percent of marginal resources. In the first three months of 2013, coal units were 57.7 percent and natural gas units were 32.4 percent of the marginal resources.

  In the PJM Day-Ahead Energy Market, during the first three months of 2014, up-to congestion transactions were marginal for 94.7 percent of marginal resources, INCs were marginal for 1.1 percent of marginal resources, DECs were marginal for 1.6 percent of marginal resources, and generation resources were marginal in only 2.4 percent of marginal resources in the first three months of 2014.

- **Demand.** Demand includes physical load and exports and virtual transactions. The PJM system peak load during the first three months of 2014 was 140,467 MW in the HE 1900 on January 7, 2014, the highest of any winter since the introduction of PJM LMP markets on April 1, 1999 (Table 3-14).

  PJM average real-time load in the first three months of 2014 increased by 7.6 percent from the first three months of 2013, from 91,337 MW to 98,317 MW.

  PJM average day-ahead demand in the first three months of 2014, including DECs and up-to congestion transactions, increased by 13.5 percent from the first three months of 2013, from 143,585 MW to 163,031 MW. The day-ahead demand growth was 77.6 percent higher than the real-time load growth as a result of the continued growth of up-to congestion transactions.

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

56 The net capacity additions are calculated by taking the different between the new generation (1,036 MW) and the retired generation (2,902 MW) after April 1, 2013.

57 The EKPC Zone was integrated on June 1, 2013.

- **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 2014, 9.5 percent of real-time load was supplied by bilateral contracts, 27.5 percent by spot market purchases and 63.0 percent by self-supply. Compared with 2013, reliance on bilateral contracts decreased 1.1 percentage points, reliance on spot market purchases increased by 2.5 percentage points and reliance on self-supply decreased by 1.4 percentage points.
- **Supply and Demand: Scarcity.** In the first three months of 2014, shortage pricing was triggered on two days in PJM. On January 6, shortage pricing was triggered by a voltage reduction action that was issued at 1950 EPT and terminated at 2045. On January 7, shortage pricing was triggered by shortage of primary and synchronized reserves starting in the hour beginning 0700 EPT and was in effect until 1220 during the morning peak as well as between 1755 and 1810 during the evening peak.

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 increased from 0.1 percent in the first three months 2013 to 0.3 percent in the first three months of 2014. In the Real-Time Energy Market, for units committed to provide energy for local constraint relief, offer-capped unit hours increased from 0.3 percent in the first three months of 2013 to 1.1 percent in the first three months of 2014.

  In the first three months of 2014, 16 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 3.0 percent in the first three months of 2013 to 0.5 percent in the first three months of 2014. In the Real-Time Energy Market, for units committed for reliability reasons, offer-capped unit hours decreased from 2.4 percent in the first three months of 2013 to 0.4 percent in the first three months of 2014.
- **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 2014, 58.3 percent of marginal units had an average markup index less than or equal to 0.0. Nonetheless, some marginal units do have substantial markups. In the first three months of 2014, 14.3 percent of units had average dollar markups greater than or equal to $150. By comparison, only 4.1 percent of units had average dollar markups greater than or equal to $150 in the first three months of 2013. Markups increased during the high demand days in January.

  In the PJM Day-Ahead Energy Market in the first three months of 2014, 86.6 percent of marginal units had average dollar markups less than zero and an average markup index less than or equal to 0.03. Nonetheless, some marginal units do have substantial markups.
- **Frequently Mitigated Units (FMU) and Associated Units (AU).** Of the 93 units eligible for FMU or AU status in at least one month during the first three months of 2014, 67 units (72.0 percent) were FMUs or AUs for all three months, and 11 units (11.8 percent) qualified in only one month in the first three months of 2014.
- **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. In the first three months of 2014, up-to congestion transactions continued to displace increment offers and decrement bids.

- **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 2014, 54.4 percent were offered as available for economic dispatch and 45.6 percent were offered as self scheduled.

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 2014 were between $800 and $900 for 4 hours, between $900 and $1,000 for 1 hour, and greater than $1,000 for 6 hours.

  PJM Real-Time Energy Market prices increased in the first three months of 2014 compared to the first three months of 2013. The load-weighted average LMP was 148.5 percent higher in the first three months of 2014 than in the first three months of 2013, $92.98 per MWh versus $37.41 per MWh.

  PJM Day-Ahead Energy Market Prices increased in the first three months of 2014 compared to the first three months of 2013. The load-weighted average LMP was 154.9 percent higher in the first three months of 2014 than in the first three months of 2013, $94.97 per MWh versus $37.26 per MWh.[58]

- **Components of LMP.** LMPs result from the operation of a market based on security-constrained, economic (least-cost) dispatch in which marginal units determine system LMPs, based on their offers. Those offers can be decomposed into fuel costs, emission costs, variable operation and maintenance costs, markup, FMU adder and the 10 percent cost adder and it is possible to decompose PJM system's load-weighted LMP by the components of unit offers.

  In the PJM Real-Time Energy Market, for the first three months of 2014, 20.8 percent of the load-weighted LMP was the result of coal costs, 40.2 percent was the result of gas costs and 1.05 percent was the result of the cost of emission allowances. The first three months of 2014 was the first time since 2008 that the cost of gas accounted for a higher percentage of the load-weighted LMP than the cost of coal.

  In the PJM Day-Ahead Energy Market, for the first three months of 2014, 26.5 percent of the load-weighted LMP was the result of the cost of gas, 20.0 percent was the result of the cost of up-to congestion transactions and 13.2 percent was the result of the cost of INC.

- **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 for the first three months of 2014, the adjusted markup component of LMP was positive, $7.12 per MWh or 7.3 percent of the PJM real-time, load-weighted average LMP. The real time load-weighted average LMP for the month of January had the highest markup component, $8.12 per MWh using adjusted cost offers. This corresponds to 6.4 percent of the real time load-weighted average LMP in January, a substantial increase over 2013. For the first three months of 2013, the adjusted markup was $0.13 per MWh or 0.3 percent of the PJM real-time load-weighted average LMP.

  In the PJM Day-Ahead Energy Market, marginal INC, DEC and transactions have zero markups. In the first three months of 2014, the adjusted markup component of LMP resulting from generation resources was $0.73 per MWh.

  Participant behavior was evaluated as competitive because the analysis of markup shows that marginal units generally make offers at, or close to,

58 Tables reporting zonal and jurisdictional load and prices are in the *2013 State of the Market Report for PJM*, Volume II, Appendix C, "Energy Market."

their marginal costs in both Day-Ahead and Real-Time Energy Markets, although the behavior of some participants during the high demand periods in January 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 -$0.13 per MWh in the first three months of 2013 and -$2.48 per MWh in the first three months of 2014. The degree of convergence, by itself, is not a measure of the competitiveness or effectiveness of the Day-Ahead Energy Market.

Scarcity

- In the first three months of 2014, shortage pricing was triggered on two days in January. On January 6, shortage pricing was triggered by a voltage reduction action that was issued at 1950 EPT and terminated at 2045. On January 7, shortage pricing was triggered by a shortage of primary and synchronized reserves starting in the hour beginning 0700 EPT and was in effect until 1220 during the morning peak as well as between 1755 and 1810 during the evening peak.
- The performance of the PJM markets under scarcity conditions raised a number of concerns including concerns related to capacity market incentives, participant offer behavior under tight market conditions, natural gas availability and pricing, demand response and interchange transactions.

Section 3 Recommendations

- The MMU recommends the elimination of FMU and AU adders. Since the implementation of FMU adders, PJM has undertaken major redesigns of its market rules addressing 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. This recommendation is currently being evaluated in the PJM stakeholder process.
- The PJM Tariff defines offer capped units as those units capped to maintain system reliability as a result of limits on transmission capability.[59] Offer capping for providing black start service does not meet this criterion. The MMU recommends that black start units not be given FMU status under the current rules.
- The MMU recommends that the definition of maximum emergency status in the tariff apply at all times rather than just during maximum emergency events.[60]
- The MMU recommends that PJM not use the ATSI Interface or create similar interfaces to set zonal prices to accommodate the inadequacies of the demand side resource capacity product.
- 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.
- 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.
- 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.
- The MMU recommends that PJM explore an interchange optimization solution with its neighboring balancing authorities that removes the need for market participants to schedule physical power.

59 PJM OATT, 6.4 Offer Price Caps., (February 25, 2014), p. 1909.
60 PJM OATT, 6A.1.3 Maximum Emergency, (February 25, 2014), p. 1740, 1795.

- There is currently no PJM documentation in the tariff or manuals explaining how hubs are created and how their definitions are changed.[61] 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.[62]
- 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.
- The MMU recommends that PJM identify and collect data on available behind the meter generation resources, including nodal location information and relevant operating parameters.
- The LMPs in excess of $1,800 per MWh on January 7, 2014, were potentially a result of the way in which PJM modeled zonal (not nodal) demand response as a marginal resource. The MMU recommends that PJM explain how LMPs are calculated when demand response is marginal.
- The MMU recommends that PJM create and implement clear, explicit and detailed rules in place that define the conditions under which PJM will purchase emergency energy while at the same time not recalling energy exports from PJM capacity resources. 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.

61 The general definition of a hub can be found in "Manual 35: Definitions and Acronyms," Revision 23 (April 11, 2014).

62 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.

Section 3 Conclusion

The MMU analyzed key elements of PJM energy market structure, participant conduct and market performance in the first three months of 2014, 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 273 MW in the first three months of 2014 compared to the first three months of 2013, while peak load increased by 13,835 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 for the first three months of 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.[63] 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-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 January. This is evidence of generally competitive behavior and competitive market outcomes, although the behavior of some participants during the high demand periods in January 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 2014.

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

Overview: Section 4, "Energy Uplift"

Energy Uplift Results

- **Energy Uplift Charges.** Total energy uplift charges increased by 178.7 percent or $472.6 million in the first three months of 2014 compared to the first three months of 2013, from $264.5 million to $737.1 million. This change was the result of an increase of $507.1 million in balancing operating reserve charges, an increase of $28.2 million in day-ahead operating reserve charges and an increase of $0.1 million in synchronous condensing charges. These increases were partially offset by a decrease of $48.1 million in reactive services charges and a decrease of $14.7 million in black start services charges.
- **Operating Reserve Rates.** The day-ahead operating reserve rate averaged $0.229 per MWh. The balancing operating reserve reliability rates averaged $1.890, $0.041 and $0.026 per MWh for the RTO, Eastern and Western regions. The balancing operating reserve deviation rates averaged $3.509, $1.013 and $0.323 per MWh for the RTO, Eastern and Western regions. The lost opportunity cost rate averaged $2.918 per MWh and the canceled resources rate averaged $0.0002 per MWh.
- **Reactive Services Rates.** The PENELEC, DPL and ATSI control zones had the three highest reactive local voltage support rates: $0.277, $0.272 and $0.185 per MWh. The reactive transfer interface support rate averaged $0.001 per MWh.

Characteristics of Credits

- **Types of units.** Combined cycles received 62.8 percent of all day-ahead generator credits and 59.8 percent of all balancing generator credits. Combustion turbines and diesels received 61.5 percent of the lost opportunity cost credits. Coal units received 73.9 percent of all reactive services credits.
- **Concentration of Energy Uplift Credits:** The top 10 units receiving energy uplift credits received 42.8 percent of all credits. The top 10 organizations received 83.6 percent of all credits. Concentration indexes for energy uplift categories classify them as highly concentrated. Day-ahead operating reserves HHI was 4889, balancing operating reserves HHI was 2919, lost opportunity cost HHI was 3647 and reactive services HHI was 7395.
- **Economic and Noneconomic Generation.** In the first three months of 2014, 90.4 percent of the day-ahead generation eligible for operating reserve credits was economic and 74.2 percent of the real-time generation eligible for operating reserve credits was economic.
- **Day-Ahead Unit Commitment for Reliability:** In the first three 2014, 4.0 percent of the total day-ahead generation was scheduled as must run by PJM, of which 21.0 percent received energy uplift payments.

Geography of Charges and Credits

- In the first three months of 2014, 91.3 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 generators, 1.9 percent by transactions at hubs and aggregates and 6.8 percent by transactions at interfaces.

Energy Uplift Issues

- **Lost Opportunity Cost Credits:** In the first three months of 2014, lost opportunity cost credits increased by $77.7 million compared to the first three months of 2013. In the first three months of 2014, resources in the top three control zones receiving lost opportunity cost credits, AEP, Dominion and PENELEC accounted for 58.2 percent of all lost opportunity cost credits, 44.8 percent of all day-ahead generation from pool-scheduled combustion turbines and diesels, 50.9 percent of all day-ahead generation not committed in real time by PJM from those unit types and 60.2 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 2014, the cost of the noneconomic operation of ALR units in the AEP Control Zone was $7.5 million.

- **Con Edison – PSEG Wheeling Contracts Support:** Certain units located near the boundary between New Jersey and New York City have been operated to support the wheeling contracts between Con-Ed and PSEG. These units are often run out of merit and received substantial balancing 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 2014, the average rate paid by a DEC in the Eastern Region would have been $0.635 per MWh, which is $5.928 per MWh less than the actual average rate paid.

January through March 2014 Energy Uplift Charges Increase

- **Day-ahead Operating Reserve Charges:** The largest impact on day-ahead operating reserves was from units that cleared in the Day-Ahead Energy Market and were economic for less than 50 percent of their scheduled run time. In the first three months of 2014, day-ahead operating reserve credits paid to such units increased by $21.3 million from $3.7 million in the first three months of 2013.
- **Balancing Operating Reserve Charges:** The largest impact on balancing operating reserve charges was credits paid to units committed for conservative operations with offers significantly higher than the LMP, primarily as a result of high natural gas prices. Energy uplift payments to units committed for reliability purposes before the operating day are allocated as balancing operating reserve charges for reliability. Balancing operating reserve charges for reliability increased by $406.2 million in the first three months of 2014 compared to the first three months of 2013.
- **Lost Opportunity Cost:** The second largest impact on balancing operating reserve charges was credits for lost opportunity cost (LOC) to units scheduled in the Day-Ahead Energy Market and not committed in real time or to units reduced in real time. LOC compensation increased by $77.2 million in the first three months of 2014 compared to the first three months of 2013.

Section 4 Recommendations

- The MMU recommends that PJM clearly identify, 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 be aware of the reason of these costs and to help ensure a long term solution to the issue of how to allocate the costs of operating reserves.
- The MMU recommends that PJM be transparent in the formulation of closed loop interfaces with adjustable limits and develop rules to reduce the levels of subjectivity around the creation and implementation of these interfaces. The MMU recommends that PJM estimate the impact such interfaces could have on additional uplift payments inside closed loops, transmission planning, offer capping, FTR and ARR revenue, ancillary services markets and the capacity market to avoid unintended consequences.
- 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 payments by unit in the PJM region.
- 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.

- The MMU recommends reincorporating the use of net regulation revenues as an offset in the calculation of balancing operating reserve credits.
- 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.
- 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.
  - 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.
  - The MMU recommends eliminating the use of the day-ahead LMP to calculate lost opportunity cost credits paid to combustion turbines and diesels scheduled in the Day-Ahead Energy Market, but not committed in real time.
  - The MMU recommends using the entire offer curve and not a single point on the offer curve to calculate energy lost opportunity cost.
- The MMU recommends that up-to congestion transactions be required to pay operating reserve charges.
- The MMU recommends eliminating the use of internal bilateral transactions (IBTs) in the calculation of deviations used to allocate balancing operating reserve charges.
- The MMU recommends reallocating the operating reserve credits paid to units supporting the Con Edison – PSEG wheeling contracts.
- 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. The MMU recommends including real-time exports 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.
- The MMU recommends enhancing the current energy uplift allocation rules to reflect the elimination of day-ahead operating reserves and the timing of commitment decisions.

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. 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).[64] 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.[65]

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.

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.[66]

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.[67] 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.[68] 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.[69]

64 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>.

65 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>.

66 The terms *PJM Region, RTO Region* and *RTO* are synonymous in the *2014 Quarterly State of the Market Report for PJM: January through March*, Section 5, "Capacity Market," and include all capacity within the PJM footprint.

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

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

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

RPM prices are locational and may vary depending on transmission constraints.[70] 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 generation, including the requirement to submit generator outage data and the linking of capacity payments to the level of unforced capacity. 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 2014, PJM installed capacity decreased 201.3 MW or 0.1 percent from 183,095.2 MW on January 1 to 182,893.9 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, 2014, 41.2 percent was coal; 29.2 percent was gas; 18.1 percent was nuclear; 6.2 percent was oil; 4.4 percent was hydroelectric; 0.5 percent was wind; 0.4 percent was solid waste; and 0.0 percent was solar.
- **Market Concentration.** In the 2014/2015 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.[71] 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.[72,73,74]
- **Imports and Exports.** Of the 416.0 MW of imports in the 2014/2015 RPM Third Incremental Auction, all 416.0 MW cleared. Of the cleared imports, 408.5 MW (98.2 percent) were from MISO.
- **Demand-Side and Energy Efficiency Resources.** Capacity in the RPM load management programs was 12,002.2 MW for June 1, 2014 as a result of cleared capacity for Demand Resources and Energy Efficiency Resources in RPM Auctions for the 2014/2015 Delivery Year (16,020.7 MW) less replacement capacity (4,018.5 MW).

Market Conduct

- **2014/2015 RPM Third Incremental Auction.** Of the 404 generation resources which submitted offers, unit-specific offer caps were calculated for six generation resources (1.5 percent). The MMU calculated offer caps for 19 generation resources (4.7 percent), of which 13 were based on the technology specific default (proxy) ACR values.

Market Performance

- The 2014/2015 RPM Third Incremental Auction was conducted in the first three months of 2014. In the 2014/2015 RPM Third Incremental Auction, the RTO clearing price for Annual Resources was $25.51 per MW-day. The weighted average capacity price for the 2014/2015 Delivery Year is $126.40 per MW-day, including all RPM Auctions for the 2014/2015 Delivery Year held through the first three months of 2014.
- The Delivery Year weighted average capacity price was $75.08 per MW-day in 2012/2013 and $116.54 per MW-day in 2013/2014.

70 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.

71 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).

72 See OATT Attachment DD § 6.5.

73 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.

74 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).

Generator Performance

- **Forced Outage Rates.** The average PJM EFORd for the first three months of 2014 was 12.7 percent, an increase from the 8.8 percent average PJM EFORd for the first three months of 2013.[75]
- **Generator Performance Factors.** The PJM aggregate equivalent availability factor for the first three months of 2014 was 83.4 percent, a decrease from the 85.3 percent PJM aggregate equivalent availability factor for the first three months of 2013.
- **Outages Deemed Outside Management Control (OMC).** In the first three months of 2014, 6.5 percent of forced outages were classified as OMC outages. 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[76,77,78,79]

- 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]
- 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.
- 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.
- 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.
- 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.
- 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.
- The MMU recommends improvements to the 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.
  - The MMU recommends that a unit which is not capable of supplying energy consistent with its day-ahead offer should reflect an appropriate outage.
  - 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.
  - 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.[82]

75 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 as resources in RPM. Data is for the three months ending March 31, 2014, as downloaded from the PJM GADS database on May 1, 2014. 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.

76 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.

77 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).

78 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).

79 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).

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).

82 For more on this issue and related incentive issues, see the IMM'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_

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 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 2014. 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 2014.[83]

The MMU has identified serious market design issues with RPM and the MMU has made specific recommendations to address those issues.[84,85,86,87]

Overview: Section 6, "Demand Response"

- **Demand Response Activity.** Economic program credits increased by $10.5 million, from $1.0 million in the first three months of 2013 to $11.6 million in the first three months of 2014, a 970 percent increase. Emergency energy credits increased by $37.1 million to $37.1 million compared to the first three months of 2013. The capacity market is the primary source of revenue to participants in PJM demand response programs. In the first three months of 2014, capacity market revenues increased by $71.8 million, or 108.8 percent, from $66.0 million in the first three months of 2013 to $137.8 million in the first three months of 2014.88

  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. Emergency demand response energy costs are not covered by LMP. Economic demand response energy costs are assigned to PJM market participants based on 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.[89]

- **Locational Dispatch of Demand Resources.** PJM dispatches demand resources on a zonal or subzonal basis when appropriate, but subzonal dispatches are only on a voluntary basis. Beginning with the 2014/2015 Delivery Year, demand resources will be dispatchable for mandatory reduction on a subzonal basis, defined by zip codes. More locational dispatch of demand resources in a nodal market improves market efficiency.

- **Emergency Event Day Analysis.** Emergency energy revenue increased by $37.1 million, from $0.0 million in the first three months of 2013 to $37.1 in the first three months of 2014. Emergency load management event rules over-calculate a participants' compliance levels. Increases in load for dispatched demand resources, negative reduction MWh values, are not netted across hours or across registrations within hours for compliance purposes, but are treated as zero. Considering all positive and negative reported values, the observed average load reduction of the seven events in the first three months of 2014 should have been 1,594.6 MW, rather than the 2,079.5 MW calculated using PJM's method. The correct calculation of compliance is 26.9 percent rather than PJM's calculated 35.1 percent. This does not include locations that did not report their load during the emergency event days.

Capacity_White_Papers_On_OPSI_Issues_20120820.pdf> (August 20, 2012).

83 For more complete conclusions, see *2013 State of the Market Report for PJM*, Section 4, "Capacity Market."

84 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).

85 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).

86 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).

87 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).

88 The total credits and MWh numbers for demand resources were calculated as of March 7, 2014 and may change as a result of continued PJM billing updates.

89 PJM: "Manual 28: Operating Agreement Accounting," Revision 64 (April 11, 2014), p 70.

Section 6 Recommendations

- The MMU recommends that there be only one demand resources product, with an obligation to respond when called for all hours of the year.
- The MMU recommends that the emergency load response program be classified as an economic program and not an emergency program.
- The MMU recommends that a daily must offer requirement apply to demand resources, comparable to the rule applicable to generation capacity resources.[90]
- The MMU recommends that 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.[91]
- The MMU recommends that the lead times for demand resources be shortened to 30 minute lead time with an hour minimum dispatch for all resources.
- The MMU recommends that demand resources be required to provide their nodal location on the electricity grid.
- The MMU recommends that demand resources measurement and verification be further modified to more accurately reflect compliance.
- The MMU recommends that compliance rules be revised to include submittal of all necessary hourly load data, and negative values when calculating event compliance across hours and registrations.
- The MMU recommends that PJM adopt the ISO-NE 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.[92]
- The MMU recommends that demand response event compliance be calculated for each hour and the penalty structure reflect hourly compliance.
- The MMU recommends that demand resources whose load drop method is designated as "Other" explicitly record the method of load drop.
- The MMU recommends that load management testing be initiated by PJM with limited warning to CSPs in order to more accurately resemble the conditions of an emergency event.

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.

If retail markets reflected hourly wholesale prices and customers 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, 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.

90 See "Complaint and Motion to Consolidate of the Independent Market Monitor for PJM," Docket No. EL14-20-000 (January 27, 2014) at 1.
91 *Id* at 1.
92 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 November 11, 2013) 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.

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 should include both increases and decreases in load. The current method applied by PJM simply ignores increases in load.

Overview: Section 7, "Net Revenue"

Net Revenue

- The net revenues reported are theoretical energy and ancillary net revenues and do not include capacity market revenues.
- Energy net revenues are significantly affected by fuel prices and energy prices. Natural gas prices and energy prices were significantly higher in the first quarter of 2014 than in the first quarter of 2013.
- Although higher energy prices increase net revenues and higher fuel costs decrease net revenues, the net result was substantial increases in net revenues for all technology types in the first three months of 2014 compared to the first three months of 2013. Energy net revenues increased by 1,444 percent for a new CT, 377 percent for a new CC, 637 percent for a new CP, 9,293 percent for a new DS, 188 percent for a new nuclear plant, 54 percent for a new wind installation, and 33 percent for a new solar installation.

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.

The net revenue results illustrate some fundamentals of the PJM wholesale power market. High loads that result in high prices tend to increase energy market net revenues for all unit types. Even a relatively small number of shortage pricing hours can significantly increase net revenues. This illustrates the potential role of scarcity pricing as a source of net revenues and also makes it more important to address the appropriate net revenue offset mechanism in the capacity market.

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.[93] 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). On March 28, 2013, the EPA issued a rule that raised the new source limits for new coal- and oil-fired power plants based on new information and analysis.[94]

- **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.[95]

  On April 29, 2014, the U.S. Supreme Court upheld EPA's Cross-State Air Pollution Rule (CSAPR), clearing the way for the EPA to implement this rule and to replace the Clean Air Interstate Rule (CAIR) now in effect.[96]

- **National Emission Standards for Reciprocating Internal Combustion Engines.** On January 14, 2013, the EPA signed a final rule regulating emissions from a wide variety of stationary reciprocating internal combustion engines (RICE).[97] RICE includes certain types of electrical generation facilities like diesel engines typically used for backup, emergency or supplemental power. RICE includes facilities located behind the meter. The rule exempts from its requirements one hundred hours of RICE operation in emergency demand response programs, provided that RICE uses ultra low sulfur diesel fuel (ULSD). Otherwise, a 15-hour exception applies. Emergency demand response programs include Demand Resources in RPM.

  Pending initiatives in Pennsylvania and the District of Columbia would reverse the EPA's exception in those jurisdictions and apply comparable regulatory standards to generation with similar operational characteristics.[98]

  In PJM's recent filing to improve its ability to dispatch DR prior to emergency system conditions, PJM proposed to retain the PJM Emergency Load Response Program apparently for the sole purpose of allowing RICE to continue to use the EPA's exception.[99] The MMU protested retention of the emergency program, particularly for the purpose of according discriminatory preference to resources that are not good for reliability, the markets or the environment.[100] An order from the Commission in this matter is now pending.

- **Greenhouse Gas Emissions Rule.** On September 20, 2013, the EPA proposed standards placing national limits on the amount of CO_2 that new power plants would be allowed to emit.[101] The proposed rule includes two limits for fossil fuel fired utility boilers and IGCC units based on the compliance period selected: 1,100 lb CO_2/MWh gross over a 12 operating month period, or 1,000–1,050 lb CO_2/MWh gross over an 84 operating

93 *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).

94 *Reconsideration of Certain New Source Issues: 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, 78 Fed. Reg. 24073 (April 24, 2013).

95 CAA § 110(a)(2)(D)(i)(I).

96 See EPA et al. v. EME Homer City Generation, L.P. et al., No. 12-1182.

97 *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).

98 *See* Pennsylvania House of Representatives, House Bill No. 1699; Council of the District of Columbia bill 20-569.

99 PJM Tariff filing, FERC Docket No. ER14-822 (December 24, 2013).

100 Comments, Complaint and Motion to Consolidate of the Independent Market Monitor for PJM, FERC Docket No. ER14-822 (January 14, 2014) at 3–6.

101 *Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units, Propose Rule*, EPA-HQ-OAR-2013-0495.

month (7-year) period. The proposed rule also includes two standards for natural gas fired stationary combustion units based on the size (MW): 1,000 lb CO_2/MWh gross for larger units (> 850 mmBtu/hr), or 1,100 lb CO_2/MWh gross for smaller units (≤ 850 mmBtu/hr). Contemporaneously, the EPA withdrew its proposed rule on the same matter, published April 13, 2012.[102]

- **Cooling Water Intakes.** Section 316(b) of the Clean Water Act (CWA) requires that cooling water intake structures reflect the best available technology for minimizing adverse environmental impacts. A final rule implementing this requirement is expected to be issued by May 16, 2014.

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.[103] 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.[104]
- **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. Auction prices in 2014 for the 2012-2014 compliance period were at $4.00 per ton, above the price floor for 2014. The clearing price is equivalent to a price of $4.41 per metric tonne, the unit used in other carbon markets.

102 *Withdrawal of Proposed Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units*, EPA-HQ-OAR-2011-0660 (September 20, 2013).
103 N.J.A.C. § 7:27-19.
104 CTs must have either water injection or selective catalytic reduction (SCR) controls; steam units must have either an SCR or and selective non-catalytic reduction (SNCR).

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, 2014, 70.6 percent of coal steam MW had some type of FGD (flue-gas desulfurization) technology to reduce SO_2 emissions from coal steam units, while 98.7 percent of coal steam MW had some type of particulate control, and 91.7 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 utilities' 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, 2014, 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. West Virginia has enacted a renewable portfolio standard, but it will not be in effect until 2015.

Renewable energy credits (RECs) provide out of market payments to qualifying resources, primarily wind and solar. The out of market payments in the form of RECs and federal production tax credits mean that these units have an incentive to generate MWh until the LMP is equal to the marginal cost of producing power minus the credit received for each MWh. As the net of marginal cost and credits can be negative, the credits can provide an incentive to make negative energy offers. These subsidies affect the offer 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. Renewable energy credit markets are markets related to the production and purchase of wholesale power, but are not subject to FERC regulation or any other market regulation or oversight. RECs markets are not transparent. Data on RECs 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. PJM markets also provide a flexible mechanism that incorporates renewable resources and renewable energy credit markets, and ensures 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.

Overview: Section 9, "Interchange Transactions"

Interchange Transaction Activity

- **Aggregate Imports and Exports in the Real-Time Energy Market.** During the first three months of 2014, PJM was a net importer of energy in the Real-Time Energy Market in January, and a net exporter of energy in February and March.[105] During the first three months of 2014, the real-time net interchange of 240.8 GWh was lower than net interchange of 1,640.5 GWh in the first three months of 2013.
- **Aggregate Imports and Exports in the Day-Ahead Energy Market.** During the first three months of 2014, PJM was a net exporter of energy in the Day-Ahead Energy Market in all months. During the first three months of 2014, the total day-ahead net interchange of -4,982.0 GWh was lower than net interchange of -6,592.7 GWh during the first three months of 2013.
- **Aggregate Imports and Exports in the Day-Ahead and the Real-Time Energy Market.** In the first three months of 2014, gross imports in the Day-Ahead Energy Market were 112.9 percent of gross imports in the Real-Time Energy Market (149.2 percent during the first three months of 2013), gross exports in the Day-Ahead Energy Market were 152.8 percent of the gross exports in the Real-Time Energy Market (243.3 percent during the first three months of 2013).
- **Interface Imports and Exports in the Real-Time Energy Market.** In the Real-Time Energy Market, for the first three months of 2014, there were net scheduled exports at 12 of PJM's 20 interfaces.
- **Interface Pricing Point Imports and Exports in the Real-Time Energy Market.** In the Real-Time Energy Market, for the first three months of 2014, there were net scheduled exports at 11 of PJM's 18 interface pricing points eligible for real-time transactions.[106]
- **Interface Imports and Exports in the Day-Ahead Energy Market.** In the Day-Ahead Energy Market, for the first three months of 2014, there were net scheduled exports at 12 of PJM's 20 interfaces.
- **Interface Pricing Point Imports and Exports in the Day-Ahead Energy Market.** In the Day-Ahead Energy Market, for the first three months of 2014, there were net scheduled exports at nine 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, for the first three months of 2014, up-to congestion transactions had net exports at six of PJM's 19 interface pricing points eligible for day-ahead transactions.

Interactions with Bordering Areas

PJM Interface Pricing with Organized Markets

- **PJM and MISO Interface Prices.** In the first three months of 2014, the direction of the average hourly flow was consistent with the real-time

105 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.

106 There is one interface pricing point eligible for day-ahead transaction scheduling only (NIPSCO).

average hourly price difference between the PJM/MISO Interface and the MISO/PJM Interface. The direction of flow was consistent with price differentials in 48.9 percent of the hours in the first three months of 2014.

- **PJM and New York ISO Interface Prices.** In the first three months of 2014, the direction of the average hourly flow was inconsistent with the average price difference between PJM/NYIS Interface and at the NYISO/PJM proxy bus. The direction of flow was consistent with price differentials in 57.8 percent of the hours in the first three months of 2014.
- **Neptune Underwater Transmission Line to Long Island, New York.** In the first three months of 2014, the average hourly flow (PJM to NYISO) was consistent with the real-time average hourly price difference between the PJM Neptune Interface and the NYISO Neptune Bus.[107] The average hourly flow in the first three months of 2014 was -518 MW.[108] (The negative sign means that the flow was an export from PJM to NYISO.) The flows were consistent with price differentials in 71.4 percent of the hours in the first three month of 2014.
- **Linden Variable Frequency Transformer (VFT) Facility.** In the first three months of 2014, the average hourly flow (PJM to NYISO) was consistent with the real-time average hourly price difference between the PJM Linden Interface and the NYISO Linden Bus.[109] The average hourly flow in the first three months of 2014 was -151 MW.[110] The flows were consistent with price differentials in 65.4 percent of the hours in the first three months of 2014.
- **Hudson DC Line.** In the first three months of 2014, the average hourly flow (PJM to NYISO) was consistent with the real-time average hourly price difference between the PJM Hudson Interface and the NYISO Hudson Bus.[111] The average hourly flow during the first three months of 2014 was -180 MW.[112] The flows were consistent with price differentials in 62.9 percent of the hours in the first three months of 2014.

107 In the first three months of 2014, there were 198 hours where there was no flow on the Neptune DC Tie line. The PJM average hourly LMP at the Neptune Interface during non-zero flows was $102.11 while the NYISO LMP at the Neptune Bus during non-zero flows was $123.52, a difference of $21.41.

108 The average hourly flow in the first three months of 2014, ignoring hours with no flow, on the Neptune DC Tie line was -570 MW.

109 In the first three months of 2014, there were 128 hours where there was no flow on the Linden VFT line. The PJM average hourly LMP at the Linden Interface during non-zero flows was $102.27 while the NYISO LMP at the Neptune Bus during non-zero flows was $109.82, a difference of $7.55.

110 The average hourly flow in the first three months of 2014, ignoring hours with no flow, on the Linden VFT line was -160 MW.

111 In the first three months of 2014, there were 841 hours where there was no flow on the Hudson line. The PJM average hourly LMP at the Hudson Interface during non-zero flows was $131.57 while the NYISO LMP at the Hudson Bus during non-zero flows was $138.09, a difference of $6.52.

Interchange Transaction Issues

- **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.

  For the first three months of 2014, net scheduled interchange was -362 GWh and net actual interchange was -243 GWh, a difference of 119 GWh. For the first three months of 2013, net scheduled interchange was 1,076 GWh and net actual interchange was 1,098 GWh, a difference of 22 GWh. This difference is inadvertent interchange.
- **PJM Transmission Loading Relief Procedures (TLRs).** PJM issued three TLRs of level 3a or higher during the first three months of 2014, compared to eight TLRs issued during the first three months of 2013.
- **Up-To Congestion.** The average number of up-to congestion bids submitted in the Day-Ahead Energy Market increased to 215,829 bids per day, with an average cleared volume of 1,486,359 MWh per day, in the first three months of 2014, compared to an average of 94,511 bids per day, with an average cleared volume of 1,121,351 MWh per day, in the first three months of 2013. (Figure 9-13).

Section 9 Recommendations

- The MMU recommends that PJM eliminate the IMO Interface Pricing Point, and assign the MISO Interface Pricing Point to transactions that originate or sink in the IESO balancing authority.
- The MMU recommends that PJM permit unlimited spot market imports as well as unlimited non-firm point-to-point willing to pay congestion

112 The average hourly flow in the first three months of 2014, ignoring hours with no flow, on the Hudson line was -295 MW.

imports and exports at all PJM Interfaces in order to improve the efficiency of the market.

- 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.
- The MMU recommends that the validation also require market participants to submit transactions on market paths that reflect the expected actual flow in order to reduce unscheduled loop flows.
- The MMU recommends that PJM implement rules to prevent sham scheduling. The MMU's proposed validation rules would address sham scheduling.
- 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 SouthIMP/EXP pricing point to transactions created under the reserve sharing agreement.
- The MMU recommends that PJM immediately provide the required 12-month notice to PEC to unilaterally terminate the Joint Operating Agreement.
- 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.

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"

Regulation Market

The PJM Regulation Market is a single market for the RTO. Regulation is provided by demand response and generation resources that must qualify to follow a regulation signal (RegA or RegD). PJM jointly optimizes regulation with synchronized reserve and energy to provide all three of these services at least cost. The PJM Regulation Market design includes three clearing price components (capability, performance, and lost opportunity cost), 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 2014, the average hourly eligible supply of regulation was 1,378 actual MW (1,016 effective MW). This is a decrease of 110 actual MW (169 effective MW) from the first three months of 2013 when the average hourly eligible supply of regulation was 1,488 actual MW (1,185 effective MW).
- **Demand.** The average hourly regulation demand was 685 actual MW (664 effective MW) in the first three months of 2014. This is a 152 actual MW

(45 effective MW) decrease in the average hourly regulation demand of 837 actual MW (708 effective MW) in the same period of the first three months of 2013.

- **Supply and Demand.** The ratio of offered and eligible regulation to regulation required averaged 2.01. This is a 13.4 percent increase over the first three months of 2013 when the ratio was 1.77.
- **Market Concentration.** In the first three months of 2014, the PJM Regulation Market had a weighted average Herfindahl-Hirschman Index (HHI) of 1972 which is classified as highly concentrated. In the first three months of 2014, the three pivotal supplier test was failed in 97 percent of hours.

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.[113] As of March 31, 2014, there were 261 resources following the RegA signal and 38 resources following the RegD signal.

Market Performance

- **Price and Cost.** The weighted average clearing price for regulation was $91.94 per MW of regulation in the first three months of 2014, an increase of $58.24 per MW of regulation, or 172.8 percent, from the first three months of 2013. The cost of regulation in the first three months of 2014 was $111.02 per MW of regulation, a $72.28 per MW of regulation, or 186.6 percent, increase from the first three months of 2013.
- **RMCP Credits.** RegD resources continue to be underpaid relative to RegA resources due to an inconsistent application of the marginal benefit factor in the optimization, assignment, pricing, and settlement processes. In the first three months of 2014, RegA resources received RMCP credits per effective MW on average 2.1 times higher than RegD resources. If the Regulation Market were functioning correctly, RegD and RegA resources would be paid equally per effective MW.

113 See the *2012 State of the Market Report for PJM*, Volume II, Appendix F "Ancillary Services Markets."

Synchronized Reserve Market

Synchronized reserve is a component of primary reserve. The Tier 2 Synchronized Reserve market includes the PJM RTO Reserve Zone and a subzone, the Mid-Atlantic Dominion Reserve Subzone (MAD). The MAD subzone is designed to ensure that transmission constraints will not prevent adequate synchronized reserves from being available in MAD when called. PJM has the right to define new zones or subzones "as needed for system reliability."[114]

Market Structure

- **Supply.** In the first three months of 2014, 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, except for two hours on January 6, 2014, and eight hours on January 7, 2014.
- **Demand.** The synchronized reserve requirement for the RTO Synchronized Reserve Zone remained at 1,375 MW where it was set in November 2012. The synchronized reserve requirement for the Mid-Atlantic Dominion Reserve Subzone remained at 1,300 MW where it was set in July 2010.
- **Supply and Demand.** All on-line generation resources are required to offer synchronized reserve. In the first three months of 2014, the ratio of on-line tier 2 offered synchronized reserve to synchronized reserve required in the Mid-Atlantic Dominion Subzone was 3.02 averaged over all hours. The highest offered to required ratio was 3.99 on January 31 and the lowest was 1.77 on March 31. For the RTO Synchronized Reserve Zone the ratio was 8.85. The highest offered to required ratio was 10.46 on January 1 and the lowest was 6.62 on March 27.
- **Market Concentration.** In the first three months of 2014, the weighted average HHI for cleared inflexible tier 2 synchronized reserve in the Mid-Atlantic Dominion Subzone was 4236 which is classified as highly

114 See PJM. "Manual 11, Energy and Ancillary Services Market Operations," Revision 64 (January 6, 2014), p. 66.

concentrated. The HHI for flexible synchronized reserve cleared during real-time market solutions (which was only 14.0 percent of all tier 2 synchronized reserve) was 8743. In the first three months of 2014, 56 percent of hours had a maximum market share greater than 40 percent. The MMU calculates that during the first three months of 2014, 57.9 percent of hours would have failed a three pivotal supplier test in the Mid-Atlantic Dominion Subzone if PJM had such a test and 37.7 percent of hours would have failed a three pivotal supplier test in the RTO Synchronized Reserve Zone if PJM had such a test.

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 in the first three months of 2014 were characterized by structural market power.

Market Conduct

- **Offers.** 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 cleared synchronized reserve weighted average price for Tier 2 synchronized reserve in the Mid-Atlantic Dominion (MAD) Subzone was $26.46 per MW in the first three months of 2014, a $19.11 increase from the first three months of 2013. The cost of tier 2 synchronized reserves per MW in MAD in the first three months of 2014 was $33.48, a $20.90 increase the cost of synchronized reserve in the first three months of 2013. For the MAD Subzone the market clearing price was 79 percent of the synchronized reserve cost per MW in the first three months of 2014, an increase from the 60 percent in the first three months of 2013.

  The cleared synchronized reserve weighted average price for tier 2 synchronized reserve in the RTO Synchronized Reserve Zone was $50.90 per MW in the first three months of 2014. The cost for tier 2 synchronized reserve in RTO Synchronized Reserve Zone was $100.53. For the RTO Synchronized Reserve Zone the market clearing price was 50.6 percent of the synchronized reserve cost per MW in the first three months of 2014.

- **Supply and Demand.** A synchronized reserve shortage occurs when the combination of tier 1 and tier 2 synchronized reserve supply is not adequate to meet the synchronized reserve requirement. The synchronized reserve requirement did not change for either the RTO Reserve Zone or the Mid-Atlantic Dominion Subzone during the first three months of 2014. There were four hours of synchronized reserve shortage in the first three months of 2014 on January 7, 2014. The shortage was in both the RTO Zone and the MAD subzone.

Non-Synchronized Reserve Market

Non-synchronized reserve is a component of primary reserve and shares its market definitions including the RTO Reserve Zone and the Mid-Atlantic Dominion Reserve subzone (MAD). After the hour ahead market solution satisfies the requirement for synchronized reserve the remainder of the primary reserve requirement is satisfied with non-synchronized reserve. Non-synchronized reserve is non-emergency energy resources not currently synchronized to the grid that can provide energy within ten minutes at the direction of PJM dispatch.

Market Structure

- **Supply.** With the exception of two hours on January 6, 2014, and eight hours on January 7, 2014, the supply of offered and eligible tier 2 synchronized reserve for the period spanning January 1, 2014 through March 31, 2014 was sufficient to cover the 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 37.8 MW of non-synchronized reserve of which 86.9 percent of cleared non-synchronized reserve was at a price of $0. In the MAD subzone, the market cleared an hourly average of 560 MW of non-synchronized reserve of which 92.7 percent was at a price of $0.

- **Supply and Demand.** The requirement for primary reserve is 1.5 times the largest contingency. There is no specific requirement for non-synchronized reserve. In the RTO Reserve Zone the primary reserve requirement is 2,063 MW. Of that 2,063 MW 1,375 MW must be synchronized to the grid. All or any portion of the remaining 688 MW is a jointly optimized solution of tier 2 synchronized reserve, tier 1 synchronized reserve, and non-synchronized reserve. In the MAD subzone the primary reserve requirement is 1,700 MW of which 1,300 MW must be synchronized to the grid. All or any portion of the remaining 400 MW can be 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.** Prices are a function of the opportunity costs of any resources taken for non-synchronized reserves. The cleared non-synchronized reserve weighted average price in the RTO Reserve Zone was $2.02 per MW for the first three months of 2014. The cleared non-synchronized reserve weighted average price in the Mid-Atlantic Dominion (MAD) Subzone was $4.56 per MW.

Day-Ahead Scheduling Reserve (DASR)

The purpose of the DASR Market is to satisfy secondary supplemental (30-minute) reserve requirements with a market-based mechanism that allows generation resources to offer their reserve energy at a price and compensates cleared supply at a single market clearing price. The DASR 30-minute reserve requirements are determined for each reliability region.[115]

Market Structure

- **Concentration.** The MMU calculates that in the first three months of 2014, 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. Eligible DASR resources consist of all resources that can provide reserve capability that can be fully converted into energy within 30 minutes as requested by PJM dispatchers.
- **Demand.** The DASR requirement in 2014 is 6.27 percent of peak load forecast, down from 6.91 percent in 2013.

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. On March 31, 2014, 56.4 percent of resources offered at $0, 65.9 percent of resources offered at $0.05 or less, 74.4 percent of resources offered at less than $1.00, and 11.5 percent resources offered at above $5 per MW.
- **DR.** Demand resources are eligible to participate in the DASR Market, but no demand resource cleared the DASR Market in the first three months of 2014.

Market Performance

- **Price.** The DASR market clearing price in the first three months of 2014 was $0.06 per MW. This is a 100 percent increase from the first three months of 2013 which had a weighted price of $0.03 per MW.

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

115 See PJM. "Manual 13: Emergency Operations," Revision 53, (June 1, 2013); pp 11-12.

to automatically remain operating at reduced levels when disconnected from the grid.[116]

In the first three months of 2014, total black start charges were $12.7 million with $5.1 million in revenue requirement charges and $7.6 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 for scheduling in the Day-Ahead Energy Market or committing in real time units that provide black start service. Black start zonal charges in the first three months of 2014 ranged from $0.02 per MW-day in the ATSI Zone (total charges were $28,280) to $3.50 per MW-day in the AEP Zone (total charges were $7,202,857).

Reactive

Reactive service, reactive supply and voltage control from generation or other sources service, is provided by generation and other sources of reactive power (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 2014, total reactive service charges were $77.7 million with $70.2 million in revenue requirement charges and $7.5 million in operating reserve charges. 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. Total charges in the first three months of 2014 ranged from $487 in the RECO Zone to $10.1 million in the AEP Zone.

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.
- 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.
- The MMU recommends that the tier 2 synchronized reserve must-offer provision of scarcity pricing be enforced.
- 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.
- 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 consider replacing the DASR market with a real time secondary reserve product that is available and dispatchable in real time.
- The MMU recommends 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.
- The MMU recommends that the three pivotal supplier test be incorporated in the DASR market.

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 a consistent implementation of 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

116 OATT Schedule 1 § 1.3BB.

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 spinning events has been an issue. Compliance with the synchronized reserve must-offer requirement has also been an issue.

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 increased by $1,050.2 million or 564.8 percent, from $185.9 million in the first three months of 2013 to $1,236.1 million in the first three months of 2014. Total congestion costs increased because of the cold weather in January, which caused higher load and prices and an increased frequency of congestion.
- **Day-Ahead Congestion.** Day-ahead congestion costs increased by $1,101.5 million or 331.9 percent, from $331.9 million in the first three months of 2013 to $1,433.3 million in the first three months of 2014.
- **Balancing Congestion.** Balancing congestion costs decreased by $51.3 million or 35.1 percent, from -$145.9 million in the first three months of 2013 to -$197.2 million in the first three months of 2014.
- **Monthly Congestion.** Monthly total congestion costs in the first three months of 2014 ranged from $165.2 million in February to $825.2 million in January.
- **Geographic Differences in CLMP.** Differences in CLMP among eastern, southern and western control zones in PJM was primarily a result of congestion on the AP South Interface, the West Interface, the Breed – Wheatland flowgate, the Cloverdale transformer, and the Bedington - Black Oak Interface.
- **Congested Facilities.** 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 2014. Day-ahead congestion frequency increased by 39.7 percent from 81,378 congestion event hours in the first three months of 2013 to 113,666 congestion event hours in the first three months of 2014. Day-ahead, congestion-event hours increased on all types of congestion facilities.

  Real-time congestion frequency increased by 71.3 percent from 5,923 congestion event hours in the first three months of 2013 to 10,144 congestion event hours in the first three months of 2014. Real-time, congestion-event hours increased on all types of congestion facilities.

  The AP South Interface was the largest contributor to congestion costs in the first three months of 2014. With $436.9 million in total congestion costs, it accounted for 35.3 percent of the total PJM congestion costs in the first three months of 2014.
- **Zonal Congestion.** AEP had the largest total congestion cost among all control zones in the first three months of 2014. AEP had -$710.8 million in total load congestion payments, -$1,088.3 million in total generation congestion credits and -$53.5 million in explicit congestion costs, resulting

in $324.1 million in net congestion costs. The AP South interface, the West Interface, the Breed – Wheatland, Monticello - East Winamac and the Benton Harbor – Palisades flowgates contributed $253.4 million, or 78.2 percent of the total AEP Control Zone congestion costs.

- **Ownership.** In the first three months of 2014, financial companies as a group were net recipients of congestion credits, and physical companies were net payers of congestion charges. UTCs are in the explicit cost category and comprise most of that category. Explicit costs are the primary source of congestion credits to financial entities. In the first three months of 2014, financial companies received $190.8 million, an increase of $162.4 million or 571.9 percent compared to the first three months of 2013. In the first three months of 2014, physical companies paid $1,426.9 million in congestion charges, an increase of $1,212.6 million or 565.8 percent compared to the first three months of 2013.

Marginal Loss Cost

- **Total Marginal Loss Costs.** Total marginal loss costs increased by $498.3 million or 179.5 percent, from $277.6 million in the first three months of 2013 to $775.9 million in the first three months of 2014. Total marginal loss costs increased because of the cold weather in January, which caused higher load and prices and an increased level of losses. The loss component of LMP increased 35.9 percent, from $0.02 in the first three months of 2013 to $0.03 in the first three months of 2014. The loss MW in PJM increased 13.8 percent, from 5,352 GWh in the first three months of 2013 to 4,705 GWh in the first three months of 2013.
- **Day-Ahead Marginal Loss Costs.** Day-ahead marginal loss costs increased by $535.0 million or 180.6 percent, from $296.2 million in the first three months of 2013 to $831.1 million in the first three months of 2014.
- **Balancing Marginal Loss Costs.** Balancing marginal loss costs decreased by $36.6 million or 196.5 percent, from -$18.6 million in the first three months of 2013 to -$55.3 million in the first three months of 2013.
- **Monthly Total Marginal Loss Costs.** Marginal loss costs in the first three months of 2014 increased compared to the first three months of 2013, by 310.3 percent in January, 114.4 percent in February and 95.3 percent in March. Monthly total marginal loss costs in the first three months of 2014 ranged from $175.4 million in March to $414.6 million in January.
- **Marginal Loss Credits.** Marginal loss credits are calculated as total energy costs (net energy costs minus net energy credits plus net inadvertent energy charges) plus total marginal loss costs (net marginal loss costs minus net marginal loss credits plus net explicit loss costs plus net inadvertent loss charges) plus net residual market adjustments. Marginal loss credit or loss surplus is the remaining loss amount from overcollection of marginal losses, after accounting for total net energy costs and net residual market adjustments, which is paid back in full to load and exports on a load ratio basis.[117] The marginal loss credits increased in the first three months of 2014 by $158.0 million or 158.9 percent, from $99.4 million in the first three months of 2013, to $257.4 million in the first three months of 2014.

Energy Cost

- **Total Energy Costs.** Total energy costs decreased by $337.3 million or 189.6 percent, from -$177.9 million in the first three months of 2013 to -$515.1 million in the first three months of 2014.
- **Day-Ahead Energy Costs.** Day-ahead energy costs decreased by $477.1 million or 246.3 percent, from -$193.7 million in the first three months of 2013 to -$670.9 million in the first three months of 2014.
- **Balancing Energy Costs.** Balancing energy costs increased by $146.8 million or 924.9 percent, from $15.9 million in the first three months of 2013 to $162.6 million in the first three months of 2014.
- **Monthly Total Energy Costs.** Monthly total energy costs in the first three months of 2014 ranged from -$272.5 million in January to -$119.6 million in March.

117 See PJM. "Manual 28: Operating Agreement Accounting," Revision 64 (April 11, 2014), pp 63-64. Note that the overcollection is not calculated by subtracting the prior calculation of average losses from the calculated total marginal losses.

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 against congestion in 2013. ARR and FTR revenues offset 97.5 percent of the total congestion costs in the Day-Ahead Energy Market and the balancing energy market within PJM for the first ten months of the 2013 to 2014 planning period. In the 2012 to 2013 planning period, total ARR and FTR revenues offset 92.6 percent of the congestion costs.

Overview: Section 12, "Planning"

Planned Generation and Retirements

- **Planned Generation.** As of March 31, 2014, 66,135 MW of capacity were in generation request queues for construction through 2024, compared to an average installed capacity of 198,894 MW as of March 31, 2014. Of the capacity in queues, 5,973 MW, or 9.0 percent, are uprates and the rest are new generators. Wind projects account for 17,218 MW of nameplate capacity or 26.0 percent of the capacity in the queues. Combined-cycle projects account for 39,985 MW of capacity or 60.5 percent of the capacity in the queues.
- **Generation Retirements.** As shown in Table 12-6, 25,902.2 MW are or are planned to be retired between 2011 and 2019, with all but 2,050.5 MW retired by the end of 2015. The AEP Zone accounts for 6,024 MW, or 23.26 percent, of all MW planned for retirement from 2014 through 2019.
- **Generation Mix.** A potentially significant change in the distribution of unit types within the PJM footprint is likely as a combined result of the location of generation resources in the queue and the location of units likely to retire. In both the Eastern MAAC (EMAAC) and the Southwestern MAAC (SWMAAC) locational deliverability areas (LDAs), the capacity mix is likely to shift to more natural gas-fired combined cycle (CC) and combustion turbine (CT) capacity.[118] Elsewhere in the PJM footprint, continued reliance on steam (mainly coal) seems likely, despite retirements of coal units.

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.[119] The process is complex and time consuming as a result of the nature of the required analyses. The cost, time and uncertainty associated 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 in completing studies.

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, and Susquehanna-Roseland.

118 EMAAC consists of the AECO, DPL, JCPL, PECO and PSEG control zones. SWMAAC consists of the BGE and Pepco control zones. See the *2013 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography" for a map of PJM LDAs.
119 OATT Parts IV & VI.

Section 12 Recommendations

The MMU recommends additional improvements to the planning process.

- There is no mechanism to permit a direct comparison, or 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. The MMU recommends the creation of such a mechanism.
- The MMU recommends that rules be implemented to permit competition to provide financing of transmission projects. This competition could reduce the cost of capital for transmission projects and significantly reduce total costs to customers.
- 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 that incumbents cannot exploit control of CIRs to block or postpone entry of competitors.[120]
- 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 could result in a conflict of interest when transmission owners have generation interests.
- 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.
- 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.

120 See "Comments of the Independent Market Monitor for PJM," <http://www.monitoringanalytics.com/reports/Reports/2012/IMM_Comments_ER12-1177-000_20120312.pdf> (Accessed December 4, 2013).

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 energy and capacity markets. But when generating units retire, there is no market mechanism in place that would require direct competition between transmission and generation to meet loads in that area. In addition, despite Order No. 1000, there is not yet a robust mechanism to permit competition to build transmission projects or to obtain least cost financing. 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 effectively forestalls the ability of generation to compete. 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.

Overview: Section 13, "FTR and ARRs"

Financial Transmission Rights

Market Structure

- **Supply.** Market participants can also sell FTRs. In the first ten months of the Monthly Balance of Planning Period FTR Auctions for the 2013 to 2014 planning period, total participant FTR sell offers were 4,990,310 MW, up from 4,627,335 MW for the same period during the 2012 to 2013 planning period.

- **Demand.** The total FTR buy bids from the first ten months of the Monthly Balance of Planning Period FTR Auctions for the 2013 to 2014 planning period increased 23.5 percent from 18,299,865 MW for the same time period of the prior planning period, to 22,593,834 MW.
- **Patterns of Ownership.** For the Monthly Balance of Planning Period Auctions, financial entities purchased 77.8 percent of prevailing flow and 87.4 percent of counter flow FTRs for January through March of 2014. Financial entities owned 68.0 percent of all prevailing and counter flow FTRs, including 58.3 percent of all prevailing flow FTRs and 84.7 percent of all counter flow FTRs during January through March 2014.

Market Behavior

- **FTR Forfeitures.** Total forfeitures for the 2013 to 2014 planning period were $531,678 for Increment Offers, Decrement Bids and, after September 1, 2013, UTC Transactions.
- **Credit Issues.** People's Power and Gas, LLC and CCES, LLC defaulted on their collateral calls and payment obligations in January 2014. Customers of these members have been reallocated accordingly, and neither company held any financial transmission rights. These two load-serving members accounted for 17 of the total 33 default events. People's Power and Gas, LLC defaulted on three collateral calls totaling approximately $687,000 and then defaulted on four related payment obligations totaling approximately $554,000. CCES, LLC defaulted on two collateral calls totaling approximately $308,000 and then defaulted on eight related payment obligations totaling approximately $2.6 million. On March 6, 2014, PJM filed with FERC to terminate membership of these two companies. The FERC authorized this request effective April 24, 2014 and PJM utilized the default allocation assessment to apply their defaulting charges of approximately $1.9 million (total defaults of these two members less collateral held) to PJM's non-defaulting members in accordance with section 15.2.2 of the OATT to non-defaulting members' March 2014 monthly invoices.[121]

  Of the remaining 16 defaults not from People's Power and Gas, LLC and CCES, LLC, 13 were from collateral defaults, averaging $822,493, and three were from payment defaults, averaging $2,328. These remaining defaults were all promptly cured. These defaults were not necessarily related to FTR positions.

Market Performance

- **Volume.** For the first ten months of the 2013 to 2014 planning period, the Monthly Balance of Planning Period FTR Auctions cleared 3,055,950 MW (13.5 percent) of FTR buy bids and 1,003,321 MW (20.1 percent) of FTR sell offers.
- **Price.** The weighted-average buy-bid FTR price in the Monthly Balance of Planning Period FTR Auctions for the first ten months of the 2013 to 2014 planning period was $0.10, down from $0.12 per MW in the 2012 to 2013 planning period.
- **Revenue.** The Monthly Balance of Planning Period FTR Auctions generated $8.3 million in net revenue for all FTRs for the first ten months of the 2013 to 2014 planning period, down from $21.7 million for the same time period in the 2012 to 2013 planning period.
- **Revenue Adequacy.** FTRs were paid at 74.5 percent of the target allocation level for the first ten months of the 2013 to 2014 planning period. Congestion revenues are allocated to FTR holders based on FTR target allocations. PJM collected $1,693.5 million of FTR revenues during the first ten months of the 2013 to 2014 planning period and $614.0 million during the entire 2012 to 2013 planning period. For the 2013 to 2014 planning period, the top sink and top source with the highest positive FTR target allocations were Dominion and the Western Hub. Similarly, the top sink and top source with the largest negative FTR target allocations were both the Western Hub.

  Target allocations values are based on FTR MW and the differences between FTR source and sink day ahead CLMPs, not on the actual congestion incurred on FTR paths. Target allocations are therefore not a good measure of congestion incurred on FTR paths and FTR payouts

121 *See* Default Allocation Assessment. OATT Section 15.2.2

relative to target allocations are not a good measure of the payout performance of FTRs.

- ARRs and FTRs served as an effective, but not total, offset against congestion. ARR and FTR revenues offset 97.5 percent of the total congestion costs in the Day-Ahead Energy Market and the balancing energy market within PJM for the first ten months of the 2013 to 2014 planning period. In the 2012 to 2013 planning period, total ARR and FTR revenues offset 92.6 percent of the congestion costs.
- **Profitability.** FTR profitability is the difference between the revenue received for an FTR and the cost of the FTR. The cost of self-scheduled FTRs is zero in the FTR profitability calculation. FTRs were profitable overall, with $677.5 million in profits for physical entities, of which $309.5 million was from self-scheduled FTRs, and $442.2 million for financial entities. Not every FTR was profitable. FTR profits were high for the first three months of 2014 due in large part to very high January congestion prices and higher than normal congestion prices in February and March.

Auction Revenue Rights

Market Structure

- **Residual ARRs.** Effective August 1, 2012, PJM is required to offer ARRs to eligible participants when a transmission outage was modeled in the annual ARR allocation, but the facility becomes available during the relevant planning year. These ARRs are automatically assigned the month before the effective date and only available on paths prorated in Stage 1 of the annual ARR allocation. Residual ARRs are only effective for single, whole months, cannot be self scheduled and their clearing prices are based on monthly FTR auction clearing prices. In the first ten months of the 2013 to 2014 planning period PJM allocated a total of 4,527.4 MW of residual ARRs with a total target allocation of $1,783,870.
- **ARR Reassignment for Retail Load Switching.** There were 52,825 MW of ARRs associated with approximately $498,800 of revenue that were reassigned in the 2012 to 2013 planning period. There were 53,988 MW of ARRs associated with approximately $309,200 of revenue that were reassigned for the first ten months of the 2013 to 2014 planning period.

Market Performance

- **Revenue Adequacy.** For the first ten months of the 2013 to 2014 planning period, the ARR target allocations were $432.7 million while PJM collected $ 662.3 million from the combined Long Term, Annual and Monthly Balance of Planning Period FTR Auctions, making ARRs revenue adequate. For the 2012 to 2013 planning period, the ARR target allocations were $587.0 million while PJM collected $653.6 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 these ARR holders in the Day-Ahead Energy Market and the balancing energy market for the first ten months of the 2013 to 2014 planning period and for the 2012 to 2013 planning period.

Section 13 Recommendations

- Report correct monthly payout ratios to reduce overstatement of underfunding problem on a monthly basis.
- Eliminate portfolio netting to eliminate cross subsidies across FTR marketplace participants.
- Eliminate subsidies to counter flow FTR holders by treating them comparably to prevailing flow FTR holders when the payout ratio is applied.
- Eliminate cross geographic subsidies.
- Improve transmission outage modeling in the FTR auction models.
- Reduce FTR sales on paths with persistent underfunding including clear rules for what defines persistent underfunding and how the reduction will be applied.

- Implement a seasonal ARR and FTR allocation system to better represent outages.
- Eliminate over allocation requirement of ARRs in the Annual ARR Allocation process.
- 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.
- The MMU recommends that PJM not use the ATSI Interface or create similar 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 implemented so as to include them in the FTR Auction model to minimize their impact on FTR funding.

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. 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. 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 as a hedge against congestion and pay for balancing congestion in order to increase the payout to holders of FTRs who are not loads.

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

The market response to the revenue adequacy issue has been to reduce bid prices and to increase bid volumes and offer volumes. Clearing prices have fallen and cleared quantities have increased.

In the 2010 to 2011 planning period, the clearing price for an FTR obligation was $0.71 per MW, and in the 2013 to 2014 planning period the clearing price was $0.30 per MW, a 57.7 percent decrease. In the 2010 to 2011 planning period, the clearing price for FTR Obligation sell offers was $0.22 per MW, and in the 2013 to 2014 planning period was $0.05 per MW for, a 340 percent decrease.

The volume of cleared buy bids and self-scheduled bids in the Annual FTR Auctions increased from 287,294 MW in the 2010 to 2011 planning period to 420,489 MW in the 2013 to 2014 planning period, an increase of 133,095 MW or 115.9 percent. The volume of cleared sell offers increased from 10,315

MW in the 2010 to 2011 planning period to 37,821 MW in the 2013 to 2014 planning period, an increase of 266.7 percent.

In June 2010, which includes the Annual, Long Term and monthly auctions, the bid volume was 3,894,566 MW, with a net bid volume of 3,177,131 MW. The net bid volume is the buy bid volume minus the sell bid volume. In June 2013, the bid volume was 7,909,805 MW (a 103.1 percent increase) and the net bid volume was 6,607,570 MW (a 108.0 percent increase). The net bid volume to bid volume ratio in June 2010 was 0.82, while the ratio was 0.84 in June 2013, indicating a slight increase in the ratio of sell offers to buy bids.

The monthly payout ratio reported by PJM monthly 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.

If netting within portfolios were eliminated and the payout ratio were calculated correctly, the payout ratio in the 2012 to 2013 planning period would have been 84.6 percent instead of the reported 67.8 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 burden of underfunding 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 result of removing portfolio netting and applying a payout ratio to counter flow FTRs would have increased the calculated payout ratio in the 2012 to 2013 planning period from the reported 67.8 percent to 88.6 percent. The MMU recommends that counter flow and prevailing flow FTRs should be treated symmetrically with respect to the application of a payout ratio.

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 underfunding; 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 FTR underfunding; and the continued sale of FTR capability on persistently underfunded pathways. 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. The end result of all the modeling differences is that too many FTRs are sold. In addition to addressing the specific modeling issues, PJM should reduce the number of FTRs sold.