

The background features a large, light green circular logo. Inside the circle, the letters 'P' and 'J' are intertwined. The 'P' is on the left, and the 'J' is on the right, with their shapes overlapping. The 'P' has a thick, dark green outline, while the 'J' has a thin white outline. The overall design is clean and modern.

# State of the Market Report for PJM

Volume 1:  
Introduction

Monitoring Analytics, LLC

Independent  
Market Monitor  
for PJM

2011

3.15.2012

## 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.<sup>1</sup>

Accordingly, Monitoring Analytics, LLC, which serves as the Market Monitoring Unit (MMU) for PJM Interconnection, L.L.C. (PJM),<sup>2</sup> and is also known as the Independent Market Monitor for PJM (IMM), submits this *2011 State of the Market Report for PJM*.

<sup>1</sup> 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).

<sup>2</sup> OATT Attachment M § II(f).



## TABLE OF CONTENTS

---

<b>INTRODUCTION</b>	<b>1</b>
2011 In Review	1
PJM Market Background	2
Conclusions	3
Role of MMU	6
Reporting	6
Monitoring	6
Market Design	7
Recommendations	8
Total Price of Wholesale Power	8
Components of Total Price	8
<b>Section 2, Energy Market</b>	<b>11</b>
Highlights	11
Recommendations	11
Overview	12
<b>Section 3, Operating Reserve</b>	<b>15</b>
Highlights	15
Recommendations	15
Overview	16
<b>Section 4, Capacity</b>	<b>18</b>
Highlights	18
Recommendations	19
Overview	19
<b>Section 5, Demand Response</b>	<b>25</b>
Highlights	25
Recommendations	25
Overview	25
<b>Section 6, Net Revenue</b>	<b>28</b>
Highlights	28
Recommendations	28
Overview	28
<b>Section 7, Environmental and Renewables</b>	<b>31</b>
Highlights	31
Recommendations	31
Overview	31
<b>Section 8, Interchange Transactions</b>	<b>34</b>
Highlights	34
Recommendations	34
Overview	36
<b>Section 9, Ancillary Services</b>	<b>43</b>
Highlights	43
Recommendations	43
Overview	44
<b>Section 10, Congestion and Marginal Losses</b>	<b>51</b>
Highlights	51
Recommendations	51
Overview	52

<b>Section 11, Generation and Transmission Planning</b>	<b>57</b>
Highlights	57
Recommendations	57
Overview	58
<b>Section 12, Financial Transmission Rights and Auction Revenue Rights.</b>	<b>60</b>
Highlights	60
Recommendations	60
Overview	60

## TABLES

---

<b>INTRODUCTION</b>	<b>1</b>
Table 1 The Energy Market results were competitive	3
Table 2 The Capacity Market results were competitive	4
Table 3 The Regulation Market results were not competitive	5
Table 4 The Synchronized Reserve Markets results were competitive	5
Table 5 The Day-Ahead Scheduling Reserve Market results were competitive	5
Table 6 The FTR Auction Markets results were competitive	6
Table 7 Total price per MWh by category and total revenues by category: 2010 and 2011	9
Table 8 Total price per MWh by category: Calendar Years 2000 through 2011	9
Table 9 Percentage of total price per MWh by category: Calendar years 2000 through 2011	10
Table 10 Annual offer-capping statistics: Calendar years 2007 through 2011	12
Table 11 Total day-ahead and balancing operating reserve charges: Calendar years 1999 to 2011	16
Table 12 PJM capacity summary (MW): June 1, 2007 to June 1, 2014	20
Table 13 RPM Related MMU Reports	24
Table 14 History of ancillary services costs per MW of Load: 2001 through 2011	50
Table 15 Total annual PJM congestion (Dollars (Millions)): Calendar years 1999 to 2011	54
Table 16 Congestion summary (By facility type): Calendar year 2011	55



## FIGURES

---

<b>INTRODUCTION</b>	<b>1</b>
Figure 1 PJM's footprint and its 18 control zones	2
Figure 2 Average PJM aggregate supply curves: Summer 2010 and 2011	12
Figure 3 PJM real-time, monthly, load-weighted, average LMP: Calendar years 2007 through 2011	13
Figure 4 Daily balancing operating reserve rates (\$/MWh)	16
Figure 5 History of capacity prices: Calendar year 1999 through 2014	22
Figure 6 Trends in the PJM equivalent demand forced outage rate (EFORd): Calendar years 2007 to 2011	22
Figure 7 PJM 2011 distribution of EFORd data by unit type	23
Figure 8 Demand Response revenue by market: Calendar years 2002 through 2011	26
Figure 9 New entrant CC net revenue and 20-year levelized fixed cost (Dollars per installed MW-year)	29
Figure 10 New entrant CP net revenue and 20-year levelized fixed cost (Dollars per installed MW-year)	29
Figure 11 Average hourly real-time generation of solar units in PJM: Calendar year 2011	33
Figure 12 PJM real-time and day-ahead scheduled import and export transaction volume history: January 1999, through December, 2011	36
Figure 13 Monthly weighted, average regulation cost and price: Calendar year 2011	45
Figure 14 Spinning events duration distribution curve, January 2009 through December 2011	46
Figure 15 Unit retirements in PJM Calendar year 2011 through 2019	58
Figure 16 Long Term, Annual and Monthly FTR Auction bid and cleared volume: June 2003 through December 2011	61
Figure 17 FTR payout ratio with adjustments by month, excluding and including excess revenue distribution: January 2004 to December 2011	





## Introduction

### 2011 In Review

The state of the PJM markets in 2011 was good. The results of the energy market and the results of the capacity market were competitive.

The goal of a competitive power market is to provide power at the lowest possible price, consistent with cost. PJM markets met that goal in 2011. The test of a competitive power market is how it reacts to change. PJM markets have passed that test so far, but that test continues. There were significant changes in the economic environment of PJM markets in 2011, and of all wholesale power markets, and change will continue in future years. 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. 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.

Gas prices fell and coal prices rose in 2011. Gas prices decreased on average by 10 percent and coal prices increased on average by 19 percent in 2011. PJM LMPs were lower. The load-weighted average LMP was five percent lower in 2011. PJM capacity prices were lower. PJM average capacity prices were 18 percent lower in 2011. Significant new environmental regulations requiring new emission control technology will take effect in 2015, including MATS and HEDD, affecting current decisions about participation in the capacity market auction to be held in May for the 2015/2016 delivery year.

The results of the market dynamics in 2011 were generally positive for gas fired units, especially new combined cycle units. Total new entrant combined cycle revenues were generally higher in 2011 and exceeded the threshold to incent new entry for most zones.

Five large plants, each over 500 MW, began generating in PJM in 2011. This is the first time since 2006 that a plant rated at more than 500 MW has come online in PJM. Overall, 5,008 MW of nameplate capacity were added in PJM in 2011. Average offered supply increased by 14,478, or 9.3 percent, from 156,003 MW in the

summer of 2010 to 170,481 MW in the summer of 2011, including the integration of the ATSI zone in the second quarter.

The results of the market dynamics in 2011 were generally negative for coal fired units, especially older, smaller coal fired units without the required technologies to meet the new environmental regulations. The profitability of coal units declined as a result of declining revenues and increased costs. Market revenues, including capacity market revenues, were not enough to cover even the going forward costs of some of these coal units. The situation was worse for units requiring additional investments to meet environmental regulations.

A total of 1,322.3 MW of generation capacity retired in 2011, and it is expected that a total of 18,886 MW will retire from 2011 through 2019, with most of this capacity retiring by the end of 2015. Units planning to retire in 2012 make up 7,189 MW, or 41 percent of all planned retirements. In addition, between 5,764 and 6,936 MW of coal generation is at risk in the PJM market areas that participate in PJM capacity markets.

The PJM capacity market makes the PJM markets more flexible and more able to adapt to the significant changes that are affecting PJM market participants. The use of a forward looking capacity market rather than reliance on real time scarcity pricing to address these issues will permit the adjustment process to occur while reducing risk and dislocations.

The changes in the economic environment make it even more critical to complete the task of getting the design of the capacity market right. In order to ensure that the appropriate market incentives exist to replace retiring units, the capacity market prices must reflect underlying supply and demand fundamentals and especially local supply and demand fundamentals. Significant factors that result in capacity market prices failing to reflect fundamentals should be addressed. This includes both the 2.5 percent reduction in demand that suppresses market prices and the continued inclusion of inferior demand side products that also suppress market prices. Demand side resources are critical to the success of PJM markets, but they no longer need special treatment. The importance of demand side resources in the capacity market make it more critical that such resources be

full capacity resources, required to interrupt whenever called.

Markets need information in order to function effectively. It is no longer acceptable that generation owners provide only 90 days notice of retirements. That is clearly not enough time for the capacity market to react. Some generation owners have voluntarily provided substantially longer notice. If the higher prices which result from retirements are to provide incentives for required new entry, notice should be at least a year. PJM should consider doing full reliability analyses of all capacity resources at risk, as soon as they are identified, to ensure that locational capacity markets are appropriately defined and that transmission upgrades are completed prior to retirements if appropriate. Continued progress is needed on the transmission interconnection process to ensure that economic generation can be built in a timely manner. State commissions have raised significant questions about whether the capacity market design will maintain local reliability. The market design must be modified to ensure that these questions are answered.

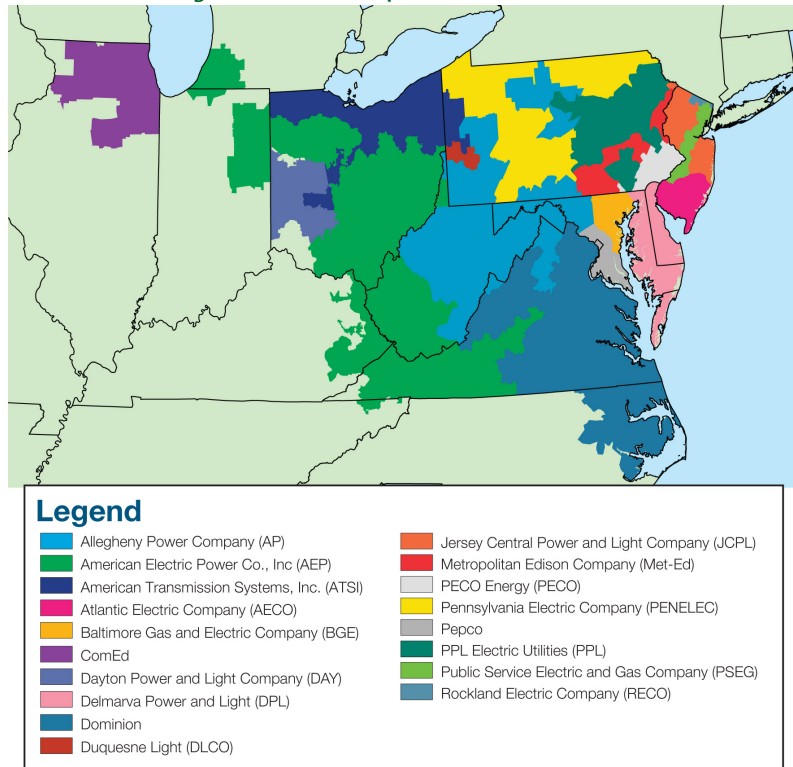
The PJM markets and PJM market participants from all sectors face significant challenges as a result of the changing economic environment. PJM and its market participants worked constructively to address these challenges in 2011 and will need to continue to do so to ensure the continued effectiveness of PJM markets.

## PJM Market Background

The PJM Interconnection, L.L.C. operates a centrally dispatched, competitive wholesale electric power market that, as of December 31, 2011, had installed generating capacity of 178,847 megawatts (MW) and more than 750 market buyers, sellers and traders of electricity<sup>1</sup> in a region including more than 58 million people<sup>2</sup> 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).<sup>3</sup> In 2011, PJM had total billings of \$35.9 billion. As part of that market operator function, PJM coordinates and directs the operation of the transmission grid and plans transmission expansion improvements to maintain grid reliability in this region.

Figure 1 PJM's footprint and its 18 control zones<sup>4,5</sup>



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

<sup>1</sup> See "Company Overview." PJM.com. PJM Interconnection L.L.C. n.d. 1 January, 2012. <<http://pjm.com/about-pjm/who-we-are/company-overview.aspx>>.

<sup>2</sup> See "Company Overview." PJM.com. PJM Interconnection L.L.C. n.d. 1 January, 2012 <<http://pjm.com/about-pjm/who-we-are/company-overview.aspx>>.

<sup>3</sup> See the 2011 State of the Market Report for PJM, Volume II, Appendix A, "PJM Geography" for maps showing the PJM footprint and its evolution prior to 2011.

<sup>4</sup> On June 1, 2011, the American Transmission Systems, Inc. (ATSI) Control Zone joined the PJM footprint.

<sup>5</sup> On January 1, 2012, the Duke Energy Ohio/Kentucky (DEOK) region joined the PJM footprint. This report covers calendar year 2011, so Figure 1 and the data in this report do not include results from the DEOK area.

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.<sup>6,7</sup>

On June 1, 2011, PJM integrated the American Transmission Systems, Inc. (ATSI) Control Zone. The metrics reported in this *2011 State of the Market Report for PJM* include the integration of the ATSI zone for the period from June through December.

## Conclusions

This report assesses the competitiveness of the markets managed by PJM in 2011, including market structure, participant behavior and market performance. This report was prepared by and represents the analysis of the independent Market Monitoring Unit (MMU) for PJM.

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 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 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 incentive competitive behavior. A flawed market design produces inefficient outcomes which cannot be corrected by competitive behavior.

The MMU concludes the following for 2011:

**Table 1 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	
<b>Market Performance</b>	<b>Competitive</b>	<b>Effective</b>

<sup>6</sup> See also the *2011 State of the Market Report for PJM, Volume II, Appendix B, "PJM Market Milestones."*

<sup>7</sup> Analysis of 2011 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. 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 2011, see the *2011 State of the Market Report for PJM, Volume II, Appendix A, "PJM Geography."*

- 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 2011 was moderately concentrated. Based on the hourly Energy Market measure, average HHI was 1203 with a minimum of 889 and a maximum of 1564 in 2011.
- 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 a number of 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 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.

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.<sup>8</sup> 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.<sup>9</sup>

**Table 2 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: Local Market	Competitive	
Market Performance	Competitive	Mixed

- The aggregate market structure was evaluated as not competitive. The entire PJM region failed the preliminary market structure screen (PMSS), which is conducted by the MMU prior to each Base Residual Auction (BRA), for every planning year for which a BRA has been run to date. 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.<sup>10</sup>
- The local market structure was evaluated as not competitive. All modeled Locational Deliverability Areas (LDAs) failed the PMSS, which is conducted by the MMU prior to each Base Residual Auction, for every planning year for which a BRA has been run to date. For almost every auction held, all LDAs failed the TPS which is conducted at the time of the auction.<sup>11</sup>
- 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 planned resource 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.

<sup>9</sup> 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.

<sup>10</sup> In the 2008/2009 RPM Third Incremental Auction, 18 participants in the RTO market passed the TPS test.

<sup>11</sup> 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.

<sup>8</sup> OATT Attachment M

- 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 and a definition of DR which permits inferior products to substitute for capacity.

**Table 3 The Regulation Market results were not competitive<sup>12</sup>**

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

- The Regulation Market structure was evaluated as not competitive because the Regulation Market had one or more pivotal suppliers which failed PJM’s three pivotal supplier (TPS) test in 82 percent of the hours in 2011.
- Participant behavior was evaluated as competitive 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.
- Market performance was evaluated as not competitive, despite competitive participant behavior, because the changes in market rules, in particular the changes to the calculation of the opportunity cost, resulted in a price greater than the competitive price in some hours, resulted in a price less than the competitive price in some hours, and because the revised market rules are inconsistent with basic economic logic.<sup>13</sup>

<sup>12</sup> As Table 3 indicates, the Regulation Market results are not the result of the offer behavior of market participants, which was competitive as a result of the application of the three pivotal supplier test. The Regulation Market results are not competitive because the changes in market rules, in particular the changes to the calculation of the opportunity cost, resulted in a price greater than the competitive price in some hours, resulted in a price less than the competitive price in some hours, and because the revised market rules are inconsistent with basic economic logic. The competitive price is the actual marginal cost of the marginal resource in the market. The competitive price in the Regulation Market is the price that would have resulted from a combination of the competitive offers from market participants and the application of the prior, correct approach to the calculation of the opportunity cost. The correct way to calculate opportunity cost and maintain incentives across both regulation and energy markets is to treat the offer on which the unit is dispatched for energy as the measure of its marginal costs for the energy market. To do otherwise is to impute a lower marginal cost to the unit than its owner does and therefore impute a higher or lower opportunity cost than its owner does, depending on the direction the unit was dispatched to provide regulation. If the market rules and/or their implementation produce inefficient outcomes, then no amount of competitive behavior will produce a competitive outcome.

<sup>13</sup> PJM agrees that the definition of opportunity cost should be consistent across all markets and should, in all markets, be based on the offer schedule accepted in the market. This would require a change to the definition of opportunity cost in the Regulation Market which is the change that the MMU has recommended. The MMU also agrees that the definition of opportunity cost should be consistent across all markets.

- Market design was evaluated as flawed because while PJM has improved the market by modifying the schedule switch determination, the lost opportunity cost calculation is inconsistent with economic logic and there are additional issues with the order of operation in the assignment of units to provide regulation prior to market clearing.

**Table 4 The Synchronized Reserve Markets results were competitive**

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

- The Synchronized Reserve Market structure was evaluated as not competitive because of high levels of supplier concentration and inelastic demand. The Synchronized Reserve Market had one or more pivotal suppliers which failed the three pivotal supplier test in 63 percent of the hours in 2011.
- 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 prices that reflect marginal costs.
- Market design was evaluated as effective because market power mitigation rules result in competitive outcomes despite high levels of supplier concentration.

**Table 5 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 the market failed the three pivotal supplier test in only a limited number of hours.
- Participant behavior was evaluated as mixed because while most offers appeared consistent with marginal costs (zero), about 13 percent of offers

reflected economic withholding, with offer prices above \$5.00.

- 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 6 The FTR Auction Markets results were competitive**

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

- The 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 in 2011.
- 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 effective because the market design provides a wide range of options for market participants to acquire FTRs and a competitive auction mechanism.

## Role of MMU

The FERC assigns three core functions to MMUs: reporting, monitoring and market design.<sup>14</sup> 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.<sup>15</sup>

## Reporting

The MMU performs its reporting function 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. The reports evaluate whether the market structure of each PJM Market is competitive or not competitive; whether participant behavior is competitive or not competitive; and, most importantly, whether the outcome of each market, the market performance, is competitive or not competitive. The MMU also evaluates the market design for each market. Market design translates participant behavior within the market structure into market performance. The MMU evaluates whether the market design of each PJM market provides the framework and incentives for competitive results. 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's reports on market issues cover specific topics in depth. For example, the MMU issues reports on RPM auctions. In addition, the MMU's reports frequently respond 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.

## 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.<sup>16</sup> The MMU has direct,

<sup>14</sup> 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).

<sup>15</sup> OATT Attachment M § IV; 18 CFR § 1c.2.

<sup>16</sup> OATT Attachment M § IV.

confidential access to the FERC.<sup>17</sup> The MMU may also refer matters to the attention of State commissions.<sup>18</sup>

The MMU monitors market behavior for violations of FERC Market Rules.<sup>19</sup> 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,<sup>20</sup> or inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies...”<sup>21</sup> The MMU also monitors PJM for compliance with the rules, in addition to market participants.<sup>22</sup>

The MMU has no prosecutorial or enforcement authority. The MMU notifies the FERC when it identifies a significant market problem or market violation.<sup>23</sup> 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<sup>24</sup> and thereafter undertakes additional investigation of the specific matter only at the direction of FERC staff.<sup>25</sup> If the problem involves an existing or proposed law, rule or practice that exposes PJM markets to the risk that market power or market manipulation could compromise the integrity of the markets, the MMU explains the issue, as appropriate, to the FERC, state regulators, stakeholders or other authorities. The MMU may also participate as a party or provide information or testimony in regulatory or other proceedings.

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).<sup>26</sup> 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.<sup>27</sup>

The MMU also reviews operational parameter limits included with unit offers,<sup>28</sup> evaluates compliance with the requirement to offer into the energy and capacity markets,<sup>29</sup> evaluates the economic basis for unit retirement requests,<sup>30</sup> and evaluates and compares offers in the Day-Ahead and Real-Time Energy Markets.<sup>31</sup>

## 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.<sup>32</sup> The MMU initiates and proposes changes to the design of such markets or the PJM Market Rules in stakeholder or regulatory proceedings.<sup>33</sup> 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.<sup>34</sup> 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.<sup>35</sup> The MMU may provide in its

17 OATT Attachment M § IV.K.3.

18 OATT Attachment M § IV.H.

19 OATT Attachment M § II(d)(4) (“FERC Market Rules” mean the market behavior rules and the prohibition against electric energy market manipulation codified by the Commission in its Rules and Regulations at 18 CFR §§ 1c.2 and 35.37, respectively; the Commission-approved PJM Market Rules and any related proscriptions or any successor rules that the Commission from time to time may issue, approve or otherwise establish... “PJM Market Rules” mean the rules, standards, procedures, and practices of the PJM Markets set forth in the PJM Tariff, the PJM Operating Agreement, the PJM Reliability Assurance Agreement, the PJM Consolidated Transmission Owners Agreement, the PJM Manuals, the PJM Regional Practices Document, the PJM-Midwest Independent Transmission System Operator Joint Operating Agreement or any other document setting forth market rules.”).

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

21 OATT Attachment M § II(h-1).

22 OATT Attachment M § IV.C.

23 OATT Attachment M § IV.I.1.

24 *Id.*

25 *Id.*

26 See OATT Attachment M-Appendix § II.A.

27 OATT Attachment M-Appendix § II.E.

28 OATT Attachment M-Appendix § II.B.

29 OATT Attachment M-Appendix § II.C.

30 OATT Attachment M-Appendix § IV.

31 OATT Attachment M-Appendix § VII.

32 OATT Attachment M § IV.D.

33 *Id.*

34 *Id.*

35 *Id.*



annual, quarterly and other reports “recommendations regarding any matter within its purview.”<sup>36</sup>

## Recommendations

Consistent with its core function to “[e]valuate existing and proposed market rules, tariff provisions and market design elements and recommend proposed rule and tariff changes,”<sup>37</sup> the MMU recommends specific enhancements to existing market rules and implementation of new rules that are required for competitive results in PJM markets and for continued improvements in the functioning of PJM markets.

## 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 7 provides the average price and total revenues paid, by component for 2010 and 2011.

Table 7 shows that Energy, Capacity and Transmission Service Charges are the three largest components of the total price per MWh of wholesale power, comprising 96.0 percent of the total price per MWh in 2011. The cost of energy was 73.4 percent, the cost of capacity was 15.5 percent and the cost of transmission service was 7.1 percent of the total price per MWh in 2011.

The total price per MWh of wholesale power in 2011, \$62.56, was 6.2 percent lower than total per MWh price of wholesale power in 2010, \$66.72. This decrease in the total price per MWh was largely attributable to the 5.0 percent decrease in the average energy price per MWh and the 20.0 percent decrease in the average price of capacity per MWh between 2010 and 2011.

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.

<sup>36</sup> OATT Attachment M § VI.A.

<sup>37</sup> 18 CFR § 35.28(g)(3)(ii)(A); see also OATT Attachment M § IV.D.

## 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.<sup>38</sup>
- The Operating Reserve (uplift) component is the average price per MWh of day ahead and real time operating reserve charges.<sup>39</sup>
- The Reactive component is the average cost per MWh of reactive supply and voltage control from generation and other sources.<sup>40</sup>
- The Regulation component is the average cost per MWh of regulation procured through the Regulation Market.<sup>41</sup>
- 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<sup>2</sup>) 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.<sup>42</sup>
- 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.<sup>43</sup>
- 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.<sup>44</sup>

<sup>38</sup> OATT §§ 13.7, 14.5, 27A & 34.

<sup>39</sup> OA Schedules 1 §§ 3.2.3 & 3.3.3.

<sup>40</sup> OATT Schedule 2 and OA Schedule 1 § 3.2.3B.

<sup>41</sup> OA Schedules 1 §§ 3.2.2, 3.2.2A, 3.3.2, & 3.3.2A; OATT Schedule 3.

<sup>42</sup> OATT Schedule 12.

<sup>43</sup> OA Schedules 1 §§ 3.2.3A.01 & OATT Schedule 6.

<sup>44</sup> OATT Schedule 1A.

- The Synchronized Reserve component is the average cost per MWh of synchronized reserve procured through the Synchronized Reserve Market.<sup>45</sup>
- The Black Start component is the average cost per MWh of black start service.<sup>46</sup>
- The RTO Startup and Expansion component is the average cost per MWh of charges to recover AEP, ComEd and DAY's integration expenses.<sup>47</sup>
- The NERC/RFC component is the average cost per MWh of NERC and RFC charges, plus any reconciliation charges.<sup>48</sup>
- The Load Response component is the average cost per MWh of day ahead and real time load response program charges to LSEs.<sup>49</sup>
- The Transmission Facility Charges component is the average cost per MWh of Ramapo Phase Angle Regulators charges allocated to PJM Mid-Atlantic transmission owners.<sup>50</sup>

**Table 7 Total price per MWh by category and total revenues by category: 2010 and 2011**

Category	2010 \$/MWh	2011 \$/MWh	Percent Change Totals	2010 Percent of Total	2011 Percent of Total
Energy	\$48.35	\$45.94	(5.0%)	72.5%	73.4%
Capacity	\$12.15	\$9.72	(20.0%)	18.2%	15.5%
Transmission Service Charges	\$4.00	\$4.42	10.5%	6.0%	7.1%
Operating Reserves (Uplift)	\$0.79	\$0.79	1.1%	1.2%	1.3%
Reactive	\$0.44	\$0.42	(6.6%)	0.7%	0.7%
PJM Administrative Fees	\$0.36	\$0.37	3.4%	0.5%	0.6%
Regulation	\$0.35	\$0.32	(6.6%)	0.5%	0.5%
Transmission Enhancement Cost Recovery	\$0.21	\$0.29	39.0%	0.3%	0.5%
Synchronized Reserves	\$0.06	\$0.09	47.4%	0.1%	0.1%
Transmission Owner (Schedule 1A)	\$0.09	\$0.09	1.5%	0.1%	0.1%
Day Ahead Scheduling Reserve (DASR)	\$0.01	\$0.05	391.9%	0.0%	0.1%
Black Start	\$0.02	\$0.02	22.4%	0.0%	0.0%
NERC/RFC	\$0.02	\$0.02	(7.6%)	0.0%	0.0%
RTO Startup and Expansion	\$0.01	\$0.01	(1.9%)	0.0%	0.0%
Load Response	\$0.00	\$0.01	28.6%	0.0%	0.0%
Transmission Facility Charges	\$0.00	\$0.00	19.1%	0.0%	0.0%
Total	\$66.72	\$62.56	(6.2%)	100.0%	100.0%

**Table 8 Total price per MWh by category: Calendar Years 2000 through 2011<sup>51</sup>**

Category	Totals (\$/MWh) 2000	Totals (\$/MWh) 2001	Totals (\$/MWh) 2002	Totals (\$/MWh) 2003	Totals (\$/MWh) 2004	Totals (\$/MWh) 2005	Totals (\$/MWh) 2006	Totals (\$/MWh) 2007	Totals (\$/MWh) 2008	Totals (\$/MWh) 2009	Totals (\$/MWh) 2010	Totals (\$/MWh) 2011
Energy	\$30.72	\$36.65	\$31.60	\$41.23	\$44.34	\$63.46	\$53.35	\$61.66	\$71.13	\$39.05	\$48.35	\$45.94
Capacity	\$0.20	\$0.32	\$0.12	\$0.08	\$0.09	\$0.03	\$0.03	\$3.97	\$8.33	\$11.02	\$12.15	\$9.72
Transmission Service Charges	\$2.17	\$3.46	\$3.37	\$3.56	\$3.26	\$2.68	\$3.15	\$3.41	\$3.65	\$4.00	\$4.00	\$4.42
Operating Reserves (Uplift)	\$0.57	\$1.07	\$0.69	\$0.86	\$0.93	\$0.97	\$0.45	\$0.63	\$0.61	\$0.48	\$0.79	\$0.79
Reactive	\$0.15	\$0.22	\$0.20	\$0.24	\$0.25	\$0.26	\$0.29	\$0.31	\$0.32	\$0.36	\$0.44	\$0.42
PJM Administrative Fees	\$0.15	\$0.36	\$0.43	\$0.54	\$0.50	\$0.38	\$0.40	\$0.38	\$0.24	\$0.31	\$0.36	\$0.37
Regulation	\$0.30	\$0.50	\$0.42	\$0.50	\$0.50	\$0.79	\$0.53	\$0.63	\$0.70	\$0.34	\$0.35	\$0.32
Transmission Enhancement Cost Recovery										\$0.09	\$0.21	\$0.29
Synchronized Reserves			\$0.11	\$0.19	\$0.16	\$0.15	\$0.10	\$0.11	\$0.09	\$0.05	\$0.06	\$0.09
Transmission Owner (Schedule 1A)	\$0.05	\$0.08	\$0.07	\$0.07	\$0.11	\$0.09	\$0.09	\$0.09	\$0.09	\$0.08	\$0.09	\$0.09
Day Ahead Scheduling Reserve (DASR)									\$0.00	\$0.00	\$0.01	\$0.05
Black Start			\$0.00	\$0.02	\$0.01	\$0.02	\$0.02	\$0.02	\$0.02	\$0.02	\$0.02	\$0.02
NERC/RFC								\$0.01	\$0.01	\$0.01	\$0.02	\$0.02
RTO Startup and Expansion			\$0.04	\$0.05	\$0.10	\$0.37	\$0.15	\$0.01	\$0.01	\$0.01	\$0.01	\$0.01
Load Response	\$0.00	\$0.00	\$0.00	\$0.02	\$0.00	\$0.00	\$0.03	\$0.07	\$0.03	\$0.00	\$0.00	\$0.01
Transmission Facility Charges	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
Total	\$34.32	\$42.66	\$37.05	\$47.36	\$50.25	\$69.20	\$58.58	\$71.30	\$85.24	\$55.85	\$66.72	\$62.56

45 OA Schedule 1 § 3.2.3A.01; PJM OATT Schedule 6.

46 OATT Schedule 6A. The Black Start charges do not include Operating Reserve charges required for units to provide Black Start Service under the ALR option.

47 OATT Attachments H-13, H-14 and H-15 and Schedule 13.

48 OATT Schedule 10-NERC and OATT Schedule 10-RFC.

49 OA Schedule 1 § 3.6.

50 OA Schedule 1 § 5.3b.

51 Data are missing for January through May of 2000 and January of 2002.

Table 9 Percentage of total price per MWh by category: Calendar years 2000 through 2011<sup>52</sup>

Category	Percentage of Total Charges 2000	Percentage of Total Charges 2001	Percentage of Total Charges 2002	Percentage of Total Charges 2003	Percentage of Total Charges 2004	Percentage of Total Charges 2005	Percentage of Total Charges 2006	Percentage of Total Charges 2007	Percentage of Total Charges 2008	Percentage of Total Charges 2009	Percentage of Total Charges 2010	Percentage of Total Charges 2011
Energy	89.5%	85.9%	85.3%	87.1%	88.2%	91.7%	91.1%	86.5%	83.4%	69.9%	72.5%	73.4%
Capacity	0.6%	0.7%	0.3%	0.2%	0.2%	0.0%	0.0%	5.6%	9.8%	19.7%	18.2%	15.5%
Transmission Service Charges	6.3%	8.1%	9.1%	7.5%	6.5%	3.9%	5.4%	4.8%	4.3%	7.2%	6.0%	7.1%
Operating Reserves (Uplift)	1.7%	2.5%	1.9%	1.8%	1.8%	1.4%	0.8%	0.9%	0.7%	0.9%	1.2%	1.3%
Reactive	0.4%	0.5%	0.5%	0.5%	0.5%	0.4%	0.5%	0.4%	0.4%	0.7%	0.7%	0.7%
PJM Administrative Fees	0.4%	0.8%	1.2%	1.1%	1.0%	0.5%	0.7%	0.5%	0.3%	0.5%	0.5%	0.6%
Regulation	0.9%	1.2%	1.1%	1.1%	1.0%	1.1%	0.9%	0.9%	0.8%	0.6%	0.5%	0.5%
Transmission Enhancement Cost Recovery										0.2%	0.3%	0.5%
Synchronized Reserves			0.3%	0.4%	0.3%	0.2%	0.2%	0.2%	0.1%	0.1%	0.1%	0.1%
Transmission Owner (Schedule 1A)	0.1%	0.2%	0.2%	0.1%	0.2%	0.1%	0.1%	0.1%	0.1%	0.2%	0.1%	0.1%
Day Ahead Scheduling Reserve (DASR)									0.0%	0.0%	0.0%	0.1%
Black Start			0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
NERC/RFC								0.0%	0.0%	0.0%	0.0%	0.0%
RTO Startup and Expansion			0.1%	0.1%	0.2%	0.5%	0.3%	0.0%	0.0%	0.0%	0.0%	0.0%
Load Response	0.0%	(0.0%)	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%
Transmission Facility Charges	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Table 8 provides the average price by component for calendar years 2000 through 2011.

Table 8 shows that from 2007 through 2011 Energy, Capacity and Transmission Service Charges are the three largest components of the total price per MWh of wholesale power, comprising more than 96.0 percent of the total price per MWh each year. Over the 2000 to 2011 period these three components were a minimum of 94.7 percent of the total price per MWh each year. Of these components, the cost of energy was consistently the most important, making up from 69.9 to 91.1 percent of the total price per MWh for the 2000 through 2011 period. The cost of capacity varied between 0.04 percent and 19.73 percent over the same period due to the introduction of a new capacity market design in 2007. Transmission Service Charges contributed from 3.9 to 9.1 percent of the total price per MWh on an annual basis for the 2000 through 2011 period.

<sup>52</sup> Data are missing for January through May of 2000 and January of 2002.

## Section 2, Energy Market

### Highlights

- Average offered supply increased by 14,478, or 9.3 percent, from 156,003 MW in the summer of 2010 to 170,481 MW in the summer of 2011. The large increase in offered supply was the result of the integration of the ATSI zone in the second quarter, plus the addition of 5,008 MW of nameplate capacity to PJM in 2011. The increases in supply were partially offset by the deactivation of twelve units (738 MW) since January 1, 2011. (See Volume II, page 23)
- In 2011, coal units provided 46.9 percent, nuclear units 34.2 percent and gas units 14.4 percent of total generation. Compared to calendar year 2010, generation from coal units decreased 0.8 percent, generation from nuclear units increased 3.3 percent, while generation from natural gas units increased 18.1 percent, and generation from oil units decreased 35.5 percent. (See Volume II, page 23)
- Five large plants (over 500 MW) began generating in PJM in 2011. This is the first time since 2006 that a plant rated at more than 500 MW has come online in PJM. Overall, 5,008 MW of nameplate capacity was added in PJM in 2011 (excluding the ATSI integration), the most since 2002. (See Volume II, page 286)
- The PJM system peak load for the summer of 2011 was 158,016 MW, which was 21,556 MW, or 15.8 percent, higher than the PJM peak load for the summer of 2010.<sup>53</sup> The ATSI transmission zone accounted for 13,953 MW in the peak hour of summer 2011. The peak load excluding the ATSI transmission zone was 144,063 MW, an increase of 7,603 MW from the 2010 peak load. (See Volume II, page 24)
- PJM average real-time load in 2011 increased by 3.7 percent from 2010, from 79,611 MW to 82,541 MW. The PJM average real-time load in 2011 would have decreased by 2.0 percent from 2010, from 79,611 MW to 78,000 MW, if the ATSI transmission zone were excluded. (See Volume II, page 38)
- PJM average day-ahead load, including DECs and up-to congestion transactions, increased in 2011 by 9.6 percent from 2010, from 103,935 MW to 113,866 MW. PJM average day-ahead load would have been 0.2 percent higher in 2011 than in 2010, from 103,935 MW to 103,746 MW if the ATSI transmission zone were excluded. (See Volume II, page 40)
- PJM average real-time generation increased by 3.9 percent in 2011 from 2010, from 82,582 MW to 85,775 MW. PJM average real-time generation would have decreased 1.4 percent in 2011 from 2010, from 82,582 MW to 81,645 MW if the ATSI transmission zone were excluded. (See Volume II, page 42)
- PJM Real-Time Energy Market prices decreased in 2011 compared to 2010. The load-weighted average LMP was 5.0 percent lower in 2011 than in 2010, \$45.94 per MWh versus \$48.35 per MWh. (See Volume II, page 45)
- PJM Day-Ahead Energy Market prices decreased in 2011 compared to 2010. The load-weighted average LMP was 5.2 percent lower in 2011 than in 2010, \$45.19 per MWh versus \$47.65 per MWh. (See Volume II, page 48)
- Levels of offer capping for local market power remained low. In 2011, 0.9 percent of unit hours and 0.4 percent of MW were offer capped in the Real-Time Energy Market and 0.0 percent of unit hours and 0.0 percent of MW were offer capped in the Day-Ahead Energy Market. (See Volume II, page 27)
- Of the 188 units that were eligible to include a Frequently Mitigated Unit (FMU) or Associated Unit (AU) adder in their cost-based offer during 2011, 54 (28.7 percent) qualified in all months, and 11 (5.9 percent) qualified in only one month of 2011. (See Volume II, page 35)
- There were no scarcity pricing events in 2011 under PJM's current Emergency Action based scarcity pricing rules. (See Volume II, page 56)

### Recommendations

- There are no recommendations in Section 2.

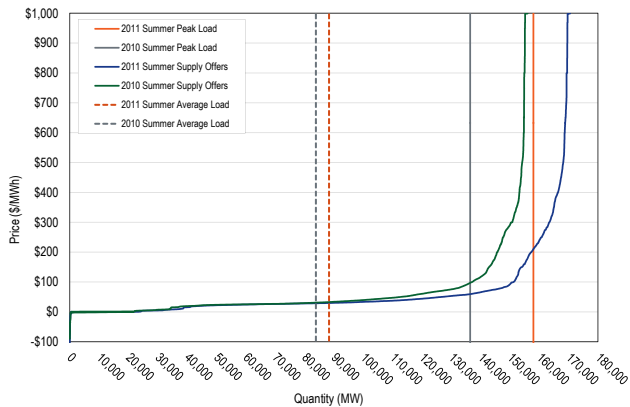
<sup>53</sup> All hours are presented and all hourly data are analyzed using Eastern Prevailing Time (EPT). See the 2011 State of the Market Report for PJM, Appendix I, "Glossary," for a definition of EPT and its relationship to Eastern Standard Time (EST) and Eastern Daylight Time (EDT).

## Overview

### Market Structure

- Supply.** Average offered supply increased by 14,478, or 9.3 percent, from 156,003 MW in the summer of 2010 to 170,481 MW in the summer of 2011.<sup>54</sup> The large increase in offered supply was the result of the integration of the ATSI zone in the second quarter, plus the addition of 5,008 MW of nameplate capacity to PJM in 2011. This includes five large plants (over 500 MW) that began generating in PJM in 2011. The increases in supply were partially offset by the deactivation of twelve units (738 MW) since January 1, 2011.

**Figure 2 Average PJM aggregate supply curves: Summer 2010 and 2011**



- Demand.** The PJM system peak load for the summer of 2011 was 158,016 MW in the HE 1700 on July 21, 2011, which was 21,556 MW, or 15.8 percent, higher than the PJM peak load for the summer of 2010, which was 136,460 MW in the HE 1700 on July 6, 2010.<sup>55</sup> The ATSI transmission zone accounted for 13,953 MW in the peak hour of summer 2011. The peak load excluding the ATSI transmission zone was 144,063 MW, also occurring on July 21, 2011, HE 1700, an increase of 7,603 MW from the 2010 peak load.
- 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.

- Local Market Structure and Offer Capping.** PJM continued to apply a flexible, targeted, real-time approach to offer capping (the three pivotal supplier test) as the trigger for offer capping in 2011. PJM offer caps units only when the local market structure is noncompetitive. Offer capping is an effective means of addressing local market power. Offer capping levels have historically been low in PJM. In the Day-Ahead Energy Market offer-capped unit hours decreased from 0.2 percent in 2010 to 0.0 percent in 2011. In the Real-Time Energy Market offer-capped unit hours decreased from 1.2 percent in 2010 to 0.9 percent in 2011.

**Table 10 Annual offer-capping statistics: Calendar years 2007 through 2011**

	Real Time		Day Ahead	
	Unit Hours Capped	MW Capped	Unit Hours Capped	MW Capped
2007	1.1%	0.2%	0.2%	0.0%
2008	1.0%	0.2%	0.2%	0.1%
2009	0.4%	0.1%	0.1%	0.0%
2010	1.2%	0.4%	0.2%	0.1%
2011	0.9%	0.4%	0.0%	0.0%

- Frequently Mitigated Units (FMU) and Associated Units (AU).** Of the 188 units that were eligible to include a Frequently Mitigated Unit (FMU) or Associated Unit (AU) adder in their cost-based offer in 2011, 54 (28.7 percent) qualified in all months, and 11 (5.9 percent) qualified in only one month of 2011.
- Local Market Structure.** In 2011, ten Control Zones experienced congestion resulting from one or more constraints binding for 100 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.<sup>56</sup>

<sup>54</sup> Calculated values shown in Section 2, "Energy Market" are based on unrounded, underlying data and may differ from calculations based on the rounded values shown in tables.

<sup>55</sup> All hours are presented and all hourly data are analyzed using Eastern Prevailing Time (EPT). See the 2011 State of the Market Report for PJM, Appendix I, "Glossary," for a definition of EPT and its relationship to Eastern Standard Time (EST) and Eastern Daylight Time (EDT).

<sup>56</sup> See the 2011 State of the Market Report for PJM, Volume II, Appendix D, "Local Energy Market Structure: TPS Results" for detailed results of the TPS test.

## Market Performance: Load, Generation and Locational Marginal Price

- **Load.** PJM average real-time load in 2011 increased by 3.7 percent from 2010, from 79,611 MW to 82,541 MW. The PJM average real-time load in 2011 would have decreased by 2.0 percent from 2010, from 79,611 MW to 78,000 MW, if the ATSI transmission zone were excluded.

PJM average day-ahead load in 2011, including DECs and up-to congestion transactions, increased by 6.2 percent from 2010, from 103,935 MW to 113,866 MW. PJM average day-ahead load in 2011, including DECs and up-to congestion transactions, would have been 0.2 percent lower than in 2010, from 103,935 MW to 103,746 MW if the ATSI transmission zone were excluded.

- **Generation.** PJM average real-time generation in 2011 increased by 3.9 percent from 2010, from 82,582 MW to 85,775 MW. PJM average real-time generation in 2011 would have decreased 1.4 percent from 2010, from 82,582 MW to 81,645 MW if the ATSI transmission zone were excluded.

PJM average day-ahead generation in 2011, including INCs and up-to congestion transactions, increased by 9.2 percent from 2010, from 107,290 MW to 117,130 MW. PJM average day-ahead generation in 2011, including INCs and up-to congestion transactions, would have been 4.8 percent higher than in 2010, from 107,290 MW to 112,424 MW if the ATSI transmission zone were excluded.

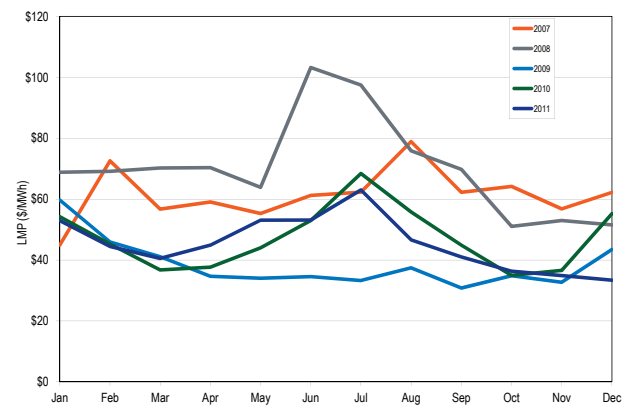
- **Generation Fuel Mix.** During 2011, coal units provided 46.9 percent, nuclear units 34.2 percent and gas units 14.4 percent of total generation. Compared to 2010, generation from coal units decreased 0.8 percent, generation from nuclear units increased 3.3 percent, generation from natural gas units increased 18.2 percent, and generation from oil units decreased 35.5 percent.
- **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 Energy Market prices decreased in 2011 compared to 2010. The system simple average LMP was 4.4 percent lower in 2011 than in 2010, \$42.84 per MWh versus \$44.83 per MWh. The load-weighted average LMP was 5.0 percent lower in 2011 than in 2010, \$45.94 per MWh versus \$48.35 per MWh.

PJM Day-Ahead Energy Market prices decreased in 2011 compared to 2010. The system simple average LMP was 4.6 percent lower in 2011 than in 2010, \$42.52 per MWh versus \$44.57 per MWh. The load-weighted average LMP was 5.2 percent lower in 2011 than in 2010, \$45.19 per MWh versus \$47.65 per MWh.<sup>57</sup>

**Figure 3 PJM real-time, monthly, load-weighted, average LMP: Calendar years 2007 through 2011**



- **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. From the perspective of a parent company of a PJM billing organization that serves load, its load could be supplied by any combination of its own generation, net bilateral market purchases and net spot market purchases. In 2011, 10.5 percent of real-time load was supplied by bilateral contracts, 26.6 percent by spot market purchases and 62.9 percent by self-supply. Compared with 2010, reliance on bilateral contracts decreased by 1.3 percentage points; reliance on spot supply increased by 6.4 percentage points; and reliance on

<sup>57</sup> Tables reporting zonal and jurisdictional load and prices are in Appendix C. See the 2011 State of the Market Report for PJM, Volume II, Appendix C, "Energy Market".

self-supply decreased by 5.1 percentage points in 2011. In 2011, 5.8 percent of day-ahead load was supplied by bilateral contracts, 24.4 percent by spot market purchases and 69.8 percent by self-supply. Compared with 2010, reliance on bilateral contracts increased by 0.9 percentage points; reliance on spot supply increased by 5.1 percentage points; and reliance on self-supply decreased by 6.1 percentage points in 2011.

## Scarcity

- **Scarcity Pricing Events in 2011.** PJM did not declare a scarcity event in 2011.
- **Scarcity and High Load Analyses.** There were no reserve shortage events in 2011. There were a total of 35 high-load hours in 2011. There were 22 Hot Weather Alerts called within the PJM footprint in 2011.

## Section 2 Conclusion

The MMU analyzed key elements of PJM Energy Market structure, participant conduct and market performance in 2011, including aggregate supply and demand, concentration ratios, three pivotal supplier test results, offer capping, participation in demand-side response programs, loads and prices in this section of the report.

Aggregate hourly supply offered increased by about 14,478 MWh in the summer of 2011 compared to the summer of 2010, while aggregate peak load increased by 21,556 MW, modifying the general supply demand balance with a corresponding impact on Energy Market prices. In the Real-Time Market, average load in 2011 increased from 2010, from 79,611 MW to 82,541 MW. 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. LMP is a broader indicator of the level of competition. While PJM has experienced price spikes, these have been limited in duration and, in general, prices in PJM have been well below the marginal cost of the highest cost unit installed on the system. The significant price spikes in PJM have been directly related to supply and demand fundamentals. In PJM, prices tend to increase as the market approaches scarcity conditions as a result of generator offers and the associated shape of the aggregate supply curve. The pattern of prices within days and across months and years illustrates how prices are directly related to demand conditions and thus also illustrates the potential significance of price elasticity of demand in affecting price. Energy Market results for 2011 generally reflected supply-demand fundamentals.

The three pivotal supplier test is applied by PJM on an ongoing basis for local energy markets in order to determine whether offer capping is required for transmission constraints. This is a flexible, targeted real-time measure of market structure which replaced the offer capping of all units required to relieve a constraint. A generation owner or group of generation owners is pivotal for a local market if the output of the owners' generation facilities is required in order to relieve a transmission constraint. When a generation owner or group of owners is pivotal, it has the ability to increase the market price above the competitive level. The three pivotal supplier test 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.<sup>58</sup>

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

<sup>58</sup> See the 2011 State of the Market Report for PJM, Volume II, Appendix D, "Local Energy Market Structure: TPS Results" for detailed results of the TPS test.

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. Any such market design modification should occur only after scarcity pricing for price signals has been implemented and sufficient experience has been gained to permit a well calibrated and gradual change in the mix of revenues.

The MMU concludes that the PJM Energy Market results were competitive in 2011.

## Section 3, Operating Reserve Highlights

- Operating reserve charges increased \$5.8 million, or 1.0 percent, from \$572.3 million in 2010, to \$578.1 million in 2011. Balancing operating reserve charges (without lost opportunity cost charges) decreased by \$49.4 million or 13.5 percent while lost opportunity cost charges increased by \$58.5 million or 51.5 percent in 2011. (See Volume II, page 67)
- Generators and real-time transactions balancing operating reserve charges were \$288.8 million, 58.9 percent of all balancing operating reserve charges. Total balancing operating reserve charges were allocated 31.4 percent as reliability charges and 68.6 percent as deviation charges. Lost opportunity cost charges were \$172.2 million or 35.2 percent of all balancing charges. The remaining 5.9 percent of balancing operating reserve charges were comprised of 1.8 percent canceled resources charges and 4.1 percent charges paid to resources controlling local transmission constraints. (See Volume II, page 68)
- The concentration of operating reserve credits among a small number of units remains high. The top 10 units receiving total operating reserve credits, which make up less than one percent of all units in PJM's footprint, received 28.1 percent of total operating reserve credits in 2011, compared to 33.2 percent in 2010. In 2011, the top generation owner received 21.0 percent of the total operating reserve credits paid. (See Volume II, page 75)
- The regional concentration of balancing operating reserves remained high in 2011, although slightly lower than 2010. In 2011, 59.3 percent of all operating reserve credits were paid to resources in the top three zones, a decrease of 4.2 percent from the 2010 share. (See Volume II, page 81)

## Recommendations

- The MMU recommends improving the process of identifying and classifying the reasons for paying operating reserve credits to both generation and demand side resources in order to ensure that market transactions pay only appropriate operating reserve charges.



- The MMU recommends that up-to congestion transactions pay balancing operating reserve charges.

## Overview

### Operating Reserve Results

- **Operating Reserve Charges.** Total operating reserve charges in 2011 were \$578.1 million. The day-ahead operating reserve charges proportion of total operating reserve charges was 15.1 percent, the synchronous condensing charges proportion was 0.1 percent, and the balancing charges proportion was 84.8 percent.
- **Operating Reserve Rates.** The day-ahead operating reserve rate averaged \$0.1068 per MWh, the balancing operating reserve RTO deviation rate averaged \$0.9455 per MWh and the balancing operating reserve RTO reliability rate averaged \$0.0681 per MWh. Lost opportunity cost rate average \$1.0678 per MWh and canceled resources rate averaged \$0.0560 per MWh.

Figure 4 Daily balancing operating reserve rates (\$/MWh)

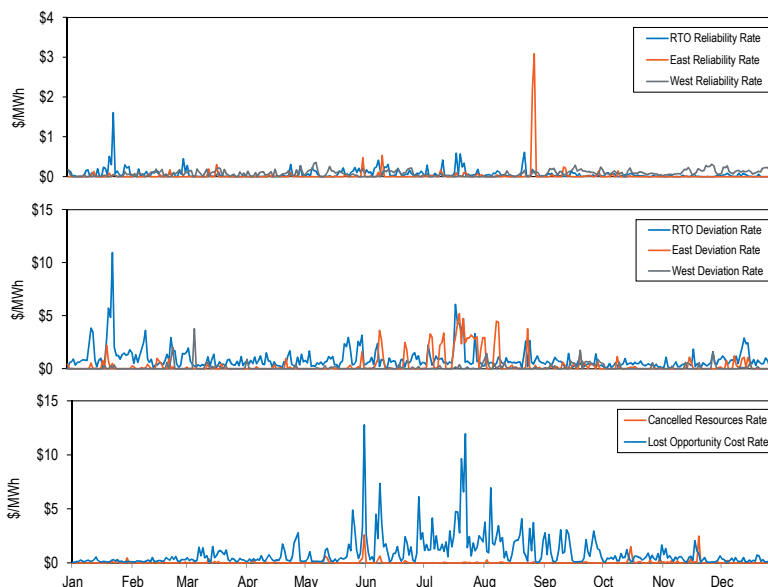


Table 11 Total day-ahead and balancing operating reserve charges: Calendar years 1999 to 2011

	Total Operating Reserve Charges	Annual Credit Change	Operating Reserve as a Percent of Total PJM Billing	Day-Ahead Rate (\$/MWh)	Balancing RTO Deviation Rate (\$/MWh)	Balancing RTO Reliability Rate (\$/MWh)
1999	\$133,897,428	NA	7.5%	NA	NA	NA
2000	\$216,985,147	62.1%	9.6%	0.341	0.535*	NA
2001	\$290,867,269	34.0%	8.7%	0.275	1.070*	NA
2002	\$237,102,574	(18.5%)	5.0%	0.164	0.787*	NA
2003	\$289,510,257	22.1%	4.2%	0.226	1.197*	NA
2004	\$414,891,790	43.3%	4.8%	0.230	1.236*	NA
2005	\$682,781,889	64.6%	3.0%	0.076	2.758*	NA
2006	\$322,315,152	(52.8%)	1.5%	0.078	1.331*	NA
2007	\$459,124,502	42.4%	1.5%	0.057	2.331*	NA
2008	\$429,253,836	(6.5%)	1.3%	0.084	2.113*	NA
2009	\$325,842,346	(24.1%)	1.2%	0.120	0.672	0.009
2010	\$572,286,706	75.6%	1.6%	0.113	0.912	0.058
2011	\$578,072,070	1.0%	1.6%	0.107	0.946	0.068

- **Operating Reserve Credits.** Balancing generator operating reserve credits were 53.3 percent, lost opportunity cost credits were 30.7 percent and day-ahead operating reserve credits were 15.5 percent of all credits. The remaining 0.5 percent was the sum of day-ahead and real-time transactions credits plus synchronous condensing credits.

## Characteristics of Credits

- **Types of units receiving operating reserve credits.** Combined cycle and conventional steam units fueled by coal received 91.5 percent of all day-ahead generator credits. Combustion turbines received 100.0 percent of the synchronous condensing credits. Combustion turbines and diesel engines received 86.7 percent of the lost opportunity cost credits. Wind units received 91.0 percent of the canceled resources credits.
- **Economic – Noneconomic Generation.** In 2011, units receiving balancing operating reserve credits were economic during 34.3 percent of all hours. Combined cycle units had the highest proportion of economic hours with 43.4 percent.
- **Geography of Balancing Credits and Charges.** Generators in the Eastern Region paid 10.1 percent of all balancing generator charges, including lost opportunity cost and canceled resources charges, and received 74.1 percent of such credits. Generators in the Western Region paid 10.2 percent of all balancing generator charges, including lost opportunity cost and canceled resources charges, and received 25.9 percent of such credits.
- **Generators Credits and Charges.** Generators paid 13.8 percent of all operating reserve charges (excluding charges for resources controlling local transmission constraints) and received 99.6 percent of all credits.

## Load Response Resource Operating Reserve Credits

- In 2011, 7.1 percent of all accepted demand reduction bids were paid through operating reserve credits. The remaining 92.9 percent was credited to end-use customers through the economic load response program.

## Reactive Service

- Total reactive service credits in 2011 were \$41.3 million. The top three zones accounted for 84.0 percent of the total credits. Combustion turbines received 51.5 percent of the total reactive service credits.

## Operating Reserve Issues

- The top 10 units receiving total operating reserve credits received 28.1 percent of all credits. The top 10 organizations received 82.1 percent of all credits. Concentration indexes for the three largest operating reserve categories classifies them as highly concentrated. Day-ahead operating reserves HHI was 4710, balancing operating reserves was 3299 and lost opportunity cost HHI was 5385.
- It appears that 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. Of the total balancing operating reserve credits paid to these units, 75.6 percent was allocated as RTO deviation charges, 20.6 percent as RTO reliability charges and the remaining 3.8 percent was allocated regionally.
- Certain units located in the AEP zone are relied on for their ALR blackstart capability and for voltage support on a regular basis even during periods when the units are not economic. The relevant blackstart units provide blackstart service under the ALR option, which means that the units must be running even if not economic. In 2011 an estimated total of \$6.5 million or 33.6 percent of all balancing operating reserve credits paid to ALR capable units was for the purpose of providing blackstart service.
- Up-to congestion transactions do not pay balancing operating reserve charges despite that they affect dispatch in the Day-Ahead Market. The impact of assigning operating reserve charges to up-to congestion transactions on the payments by other participants would be significant.

## Section 3 Conclusion

Day-ahead and real-time operating reserve credits are 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. Sometimes referred to as uplift or make whole, these payments are intended to be one of the incentives to generation owners to offer their energy to the PJM Energy Market at marginal cost and to operate their units at the direction of PJM dispatchers. These credits are paid by PJM market participants as operating reserve charges.

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

The level of operating reserve credits paid to specific units depends on the level of the unit's energy offer, the unit's operating parameters and the decisions of PJM operators. Operating reserve credits result in part from decisions by PJM operators, who follow reliability requirements and market rules, to start units or to keep units operating even when hourly LMP is less than the offer price including energy, startup and no-load offers.

PJM has improved its oversight of operating reserves and continues to review and measure daily operating reserve performance, to analyze issues and resolve them in a timely manner, to make better information more readily available to dispatchers and to emphasize the impact of dispatcher decisions on operating reserve charge levels. However, given the impact of operating reserve charges on market participants, particularly virtual market participants, PJM should take another step towards more precise definition of the reasons for incurring operating reserve charges and about the necessity of paying operating reserve charges in some cases. The goal should be to have dispatcher decisions reflected in transparent market outcomes to the maximum extent possible and to minimize the level and rate of operating reserve charges.

## Section 4, Capacity Highlights

- In calendar year 2011, PJM installed capacity increased 14,826.8 MW or 8.9 percent from 166,410.0 MW on January 1 to 178,846.5 MW on December 31, primarily due to the integration of the American Transmission Systems, Inc. (ATSI) Control Zone into PJM. Installed capacity includes net capacity imports and exports and can vary on a daily basis. (See Volume II, page 91)
- The 2011/2012 RPM Third Incremental Auction, 2014/2015 RPM Base Residual Auction, 2012/2013 RPM Second Incremental Auction, and the 2013/2014 First Incremental Auction were run in calendar year 2011. In the 2011/2012 RPM Third Incremental Auction, the RTO clearing price was \$5.00 per MW-day. In the 2014/2015 RPM Base Residual Auction, the RTO clearing price for Limited Resources was \$125.47 per MW-day, and the RTO clearing price for Extended Summer and Annual Resources was \$125.99 per MW-day. In the 2012/2013 RPM Second Incremental Auction, the RTO resource clearing price was \$13.01 per MW-day, and the EMAAC resource clearing price was \$48.91 per MW-day. In the 2013/2014 RPM First Incremental Auction, the RTO resource clearing price was \$20.00 per MW-day, the EMAAC resource clearing price was \$178.85 per MW-day, and the SWMAAC resource clearing price was \$54.82 per MW-day. (See Volume II, page 109)
- All LDAs and the entire PJM Region failed the preliminary market structure screen (PMSS) for the 2014/2015 Delivery Year. (See Volume II, page 95)
- Capacity in the RPM load management programs was 9,688.3 MW for June 1, 2011. (See Volume II, page 100)
- Annual weighted average capacity prices increased from a Capacity Credit Market (CCM) weighted average price of \$5.73 per MW-day in 2006 to an RPM weighted-average price of \$164.71 per MW-day in 2010 and then declined to \$127.05 per MW-day in 2014. (See Volume II, page 109)
- Average PJM equivalent demand forced outage rate (EFORd) increased from 7.2 percent in 2010 to 7.9 percent in 2011. (See Volume II, page 112)

- The PJM aggregate equivalent availability factor (EAF) decreased from 84.9 percent in 2010 to 83.7 percent in 2011. The equivalent maintenance outage factor (EMOF) increased from 2.8 percent in 2010 to 3.1 percent in 2011, the equivalent planned outage factor (EPOF) increased from 7.4 percent in 2010 to 7.9 percent in 2011, and the equivalent forced outage factor (EFOF) increased from 4.9 percent in 2010 to 5.3 percent in 2011. (See Volume II, page 112)

## Recommendations

- The MMU recommends that the RPM market structure, definitions and rules be modified to improve the efficiency of market prices and to ensure that market prices reflect the forward locational marginal value of capacity.
- The MMU recommends that the obligations of capacity resources be more clearly defined in the market rules.
- The MMU recommends that the performance incentives in the RPM Capacity Market design be strengthened.
- The MMU recommends that the terms of Reliability Must Run (RMR) service be reviewed, refined and standardized.

## Overview

### 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.<sup>59</sup>

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.<sup>60</sup> 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.<sup>61</sup> Previously, First, Second, and Third Incremental Auctions were conducted 23, 13 and four months, prior to the delivery year. 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.<sup>62</sup>

RPM prices are locational and may vary depending on transmission constraints.<sup>63</sup> 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-side 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 calendar year 2011, PJM installed capacity resources increased from 166,410.2 MW on January 1 to 178,846.5, primarily due to the integration of the American Transmission Systems, Inc. (ATSI) Control Zone into PJM.

<sup>59</sup> The terms *PJM Region*, *RTO Region* and *RTO* are synonymous in the 2011 *State of the Market Report for PJM*, Section 4, "Capacity Market" and include all capacity within the PJM footprint.  
<sup>60</sup> See 126 FERC ¶ 61,275 (2009) at P 86.

<sup>61</sup> See *PJM Interconnection, LLC*, Letter Order in Docket No. ER10-366-000 (January 22, 2010).

<sup>62</sup> See 126 FERC ¶ 61,275 (2009) at P 88.

<sup>63</sup> 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.

Table 12 PJM capacity summary (MW): June 1, 2007 to June 1, 2014<sup>64</sup>

	01-Jun-07	01-Jun-08	01-Jun-09	01-Jun-10	01-Jun-11	01-Jun-12	01-Jun-13	01-Jun-14
Installed capacity (ICAP)	163,721.1	164,444.1	166,916.0	168,061.5	172,666.6	181,159.7	197,775.0	210,812.4
Unforced capacity (UCAP)	154,076.7	155,590.2	157,628.7	158,634.2	163,144.3	171,147.8	186,588.0	199,063.2
Cleared capacity	129,409.2	129,597.6	132,231.8	132,190.4	132,221.5	136,143.5	152,743.3	149,974.7
Make-whole	0.0	0.0	0.0	0.0	43.0	222.1	14.0	112.6
RPM reliability requirement (pre-FRR)	148,277.3	150,934.6	153,480.1	156,636.8	154,251.1	157,488.5	173,549.0	178,086.5
RPM reliability requirement (less FRR)	125,805.0	128,194.6	130,447.8	132,698.8	130,658.7	133,732.4	149,988.7	148,323.1
RPM net excess	5,240.5	5,011.1	8,265.5	7,728.0	10,638.4	5,976.5	6,518.3	5,472.3
Imports	2,809.2	2,460.3	2,505.4	2,750.7	6,420.0	3,831.6	4,348.2	4,299.4
Exports	(3,938.5)	(3,838.1)	(2,194.9)	(3,147.4)	(3,158.4)	(2,637.1)	(2,438.4)	(1,243.1)
Net exchange	(1,129.3)	(1,377.8)	310.5	(396.7)	3,261.6	1,194.5	1,909.8	3,056.3
DR cleared	127.6	536.2	892.9	939.0	1,364.9	7,047.2	9,281.9	14,118.4
EE cleared						568.9	679.4	822.1
ILR	1,636.3	3,608.1	6,481.5	8,236.4	9,032.6			
FRR DR	445.6	452.8	423.6	452.9	452.9	488.1	488.6	518.1
Short-Term Resource Procurement Target						3,343.3	3,749.7	3,708.1

- PJM Installed Capacity by Fuel Type.** Of the total installed capacity at the end of calendar year 2011, 42.0 percent was coal; 28.3 percent was gas; 18.2 percent was nuclear; 6.3 percent was oil; 4.5 percent was hydroelectric; 0.4 percent was solid waste; 0.4 percent was wind, and 0.0 percent was solar.
- Supply.** Total internal capacity increased 851.8 MW from 159,030.9 MW on June 1, 2010, to 159,882.7 MW on June 1, 2011. This increase was the result of the classification of Duquesne resources as external at the time of the 2011/2012 RPM Base Residual Auction (-3,006.6 MW), new generation (2,203.7 MW), reactivated generation (486.9 MW), net generation capacity modifications (cap mods) (439.0 MW), Demand Resource (DR) modifications (684.4 MW), and the EFORd effect due to lower sell offer EFORds (44.4 MW).
- Demand.** There was a 2,385.7 MW decrease in the RPM reliability requirement from 156,636.8 MW on June 1, 2010, to 154,251.1 MW on June 1, 2011. This decrease was due to the exclusion of the Duquesne Zone from the preliminary forecast peak load for the 2011/2012 RPM Base Residual Auction. On June 1, 2011, PJM EDCs and their affiliates maintained a large market share of load obligations under RPM, together totaling 71.4 percent, down from 77.7 percent on June 1, 2010.
- Market Concentration.** For the 2011/2012, 2012/2013, 2013/2014, and 2014/2015 RPM Auctions, all defined markets failed the preliminary market structure screen (PMSS). In the 2011/2012 RPM First Incremental Auction, 2011/2012 ATSI Integration Auction, 2011/2012 RPM Third Incremental Auction, 2012/2013 RPM First Incremental Auction, 2012/2013 ATSI Integration Auction, 2012/2013 RPM Second Incremental Auction, 2013/2014 BRA, and 2013/2014 RPM First Incremental Auction failed the three pivotal supplier (TPS) market structure test.<sup>65</sup> In the 2012/2013 BRA, all participants in the RTO as well as MAAC, PSEG North, and DPL South RPM markets failed the TPS test, and six participants included in the incremental supply of EMAAC passed the TPS test. In the 2014/2015 BRA, all participants in the RTO and PSEG North RPM markets failed the TPS test, and seven participants in the incremental supply in MAAC passed the TPS test. 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

<sup>64</sup> Prior to the 2012/2013 Delivery Year, net excess under RPM was calculated as cleared capacity plus make-whole MW less the reliability requirement plus ILR. For 2007/2008 through 2011/2012, certified ILR was used in the calculation, because the certified ILR data are now available. For the 2012/2013 Delivery Year and beyond, net excess under RPM is calculated as cleared capacity plus make-whole MW less the reliability requirement plus the Short-Term Resource Procurement Target.

<sup>65</sup> As of December 31, 2011, there are 24 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).

cap, and the submitted sell offer, absent mitigation, would have increased the market clearing price.<sup>66,67,68</sup>

- **Imports and Exports.** Net exchange increased 3,658.3 MW from June 1, 2010 to June 1, 2011. Net exchange, which is imports less exports, increased due to an increase in imports of 3,699.3 MW primarily due to the reclassification of the Duquesne resources, offset by an increase in exports of 11.0 MW.
- **Demand-Side and Energy Efficiency Resources.** Under RPM, demand-side resources in the Capacity Market increased by 1,005.3 MW from 8,683.0 MW on June 1, 2010 to 9,688.3 MW on June 1, 2011. Demand-side resources include Demand Resources (DR) and Energy Efficiency (EE) resources cleared in RPM Auctions and certified/forecast interruptible load for reliability (ILR). Effective with the 2012/2013 Delivery Year, ILR was eliminated. Starting with the 2012/2013 Delivery Year and also for incremental auctions in the 2011/2012 Delivery Year, the Energy Efficiency Resource type is eligible to be offered in RPM Auctions.<sup>69</sup>

## Market Conduct

- **2011/2012 RPM Base Residual Auction.**<sup>70</sup> Of the 1,125 generation resources which submitted offers, unit-specific offer caps were calculated for 145 resources (12.9 percent). The MMU calculated offer caps for 470 resources (41.8 percent), of which 301 were based on the technology specific default (proxy) avoidable cost rate (ACR) values.
- **2011/2012 RPM First Incremental Auction.**<sup>71</sup> Of the 129 generation resources which submitted offers, unit-specific offer caps were calculated for 19 resources (14.7 percent). The MMU calculated offer caps for 68 resources (52.8 percent), of which 47 were based on the technology specific default (proxy) ACR values.
- **2011/2012 ATSI Integration Auction.**<sup>72</sup> Of the 141 generation resources which submitted offers, 52 resources elected the offer cap option of 1.1 times the BRA clearing price (36.9 percent). Unit-specific offer caps were calculated for four resources (2.8 percent). The MMU calculated offer caps for 64 resources (45.3 percent), of which 57 were based on the technology specific default (proxy) ACR values.
- **2011/2012 RPM Third Incremental Auction.** Of the 398 generation resources which submitted offers, 214 resources elected the offer cap option of 1.1 times the BRA clearing price (53.8 percent). Unit-specific offer caps were calculated for zero resources (0.0 percent). The MMU calculated offer caps for 23 resources (5.8 percent), of which 21 were based on the technology specific default (proxy) ACR values.
- **2012/2013 RPM Base Residual Auction.**<sup>73</sup> Of the 1,133 generation resources which submitted offers, unit-specific offer caps were calculated for 120 resources (10.6 percent). The MMU calculated offer caps for 607 resources (53.6 percent), of which 479 were based on the technology specific default (proxy) ACR values.
- **2012/2013 ATSI Integration Auction.**<sup>74</sup> Of the 173 generation resources which submitted offers, 26 resources elected the offer cap option of 1.1 times the BRA clearing price (15.0 percent). Unit-specific offer caps were calculated for 12 resources (6.9 percent). The MMU calculated offer caps 131 resources (75.7 percent), of which 117 were based on the technology specific default (proxy) ACR values.
- **2012/2013 RPM First Incremental Auction.** Of the 162 generation resources which submitted offers, unit-specific offer caps were calculated for 14 resources (8.6 percent). The MMU calculated offer caps for 108 resources (66.6 percent), of which 92 were based on the technology specific default (proxy) ACR values.

66 OATT Attachment DD (Reliability Pricing Model) § 6.5.

67 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.

68 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).

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

70 For a more detailed analysis of the 2011/2012 RPM Base Residual Auction, see "Analysis of the 2011/2012 RPM Auction Revised" <<http://www.monitoringanalytics.com/reports/Reports/2008/20081002-review-of-2011-2012-rpm-auction-revised.pdf>> (October 1, 2008).

71 For a more detailed analysis of the 2011/2012 RPM First Incremental Auction, see "Analysis of the 2011/2012 RPM First Incremental Auction" <[http://www.monitoringanalytics.com/reports/Reports/2011/Analysis\\_of\\_2011\\_2012\\_RPM\\_First\\_Incremental\\_Auction\\_20110106.pdf](http://www.monitoringanalytics.com/reports/Reports/2011/Analysis_of_2011_2012_RPM_First_Incremental_Auction_20110106.pdf)> (January 6, 2011).

72 For a more detailed analysis of the 2011/2012 ATSI Integration Auction, see "Analysis of the 2011/2012 and 2012/2013 ATSI Integration Auctions" <[http://www.monitoringanalytics.com/reports/Reports/2011/Analysis\\_of\\_2011\\_2012\\_and\\_2012\\_2013\\_ATSI\\_Integration\\_Auctions\\_20110114.pdf](http://www.monitoringanalytics.com/reports/Reports/2011/Analysis_of_2011_2012_and_2012_2013_ATSI_Integration_Auctions_20110114.pdf)> (January 14, 2011).

73 For a more detailed analysis of the 2012/2013 RPM Base Residual Auction, see "Analysis of the 2012/2013 RPM Base Residual Auction" <[http://www.monitoringanalytics.com/reports/Reports/2009/Analysis\\_of\\_2012\\_2013\\_RPM\\_Base\\_Residual\\_Auction\\_20090806.pdf](http://www.monitoringanalytics.com/reports/Reports/2009/Analysis_of_2012_2013_RPM_Base_Residual_Auction_20090806.pdf)> (August 6, 2009).

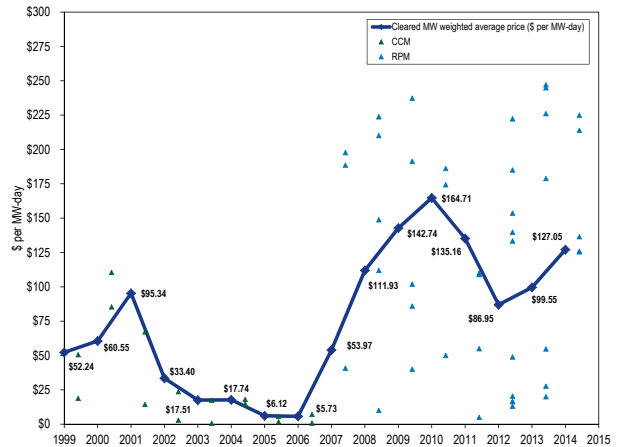
74 For a more detailed analysis of the 2012/2013 ATSI Integration Auction, see "Analysis of the 2011/2012 and 2012/2013 ATSI Integration Auctions" <[http://www.monitoringanalytics.com/reports/Reports/2011/Analysis\\_of\\_2011\\_2012\\_and\\_2012\\_2013\\_ATSI\\_Integration\\_Auctions\\_20110114.pdf](http://www.monitoringanalytics.com/reports/Reports/2011/Analysis_of_2011_2012_and_2012_2013_ATSI_Integration_Auctions_20110114.pdf)> (January 14, 2011).

- **2012/2013 RPM Second Incremental Auction.** Of the 188 generation resources which submitted offers, unit-specific offer caps were calculated for 8 resources (4.3 percent). The MMU calculated offer caps for 88 resources (46.8 percent), of which 80 were based on the technology specific default (proxy) ACR values.
- **2013/2014 RPM Base Residual Auction.** 75 Of the 1,170 generation resources which submitted offers, unit-specific offer caps were calculated for 107 resources (9.1 percent). The MMU calculated offer caps for 700 resources (59.9 percent), of which 587 were based on the technology specific default (proxy) ACR values.
- **2013/2014 RPM First Incremental Auction.** Of the 192 generation resources which submitted offers, unit-specific offer caps were calculated for 27 resources (14.1 percent). The MMU calculated offer caps for 101 resources (52.6 percent), of which 74 were based on the technology specific default (proxy) ACR values.
- **2014/2015 RPM Base Residual Auction.** Of the 1,152 generation resources which submitted offers, unit-specific offer caps were calculated for 141 resources (12.2 percent). The MMU calculated offer caps for 698 resources (60.6 percent), of which 550 were based on the technology specific default (proxy) ACR values.

**Market Performance**

- Annual weighted average capacity prices increased from a CCM weighted average price of \$5.73 per MW-day in 2006 to an RPM weighted-average price of \$135.16 per MW-day in 2011 and then declined to \$127.05 per MW-day in 2014.

**Figure 5 History of capacity prices: Calendar year 1999 through 2014<sup>76</sup>**

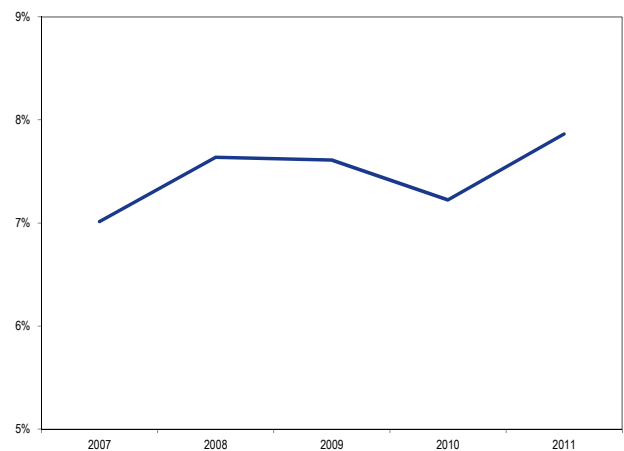


- RPM net excess increased 2,910.4 MW from 7,728.0 MW on June 1, 2010, to 10,638.4 MW on June 1, 2011.
- For the 2011/2012 planning year, RPM annual charges to load totaled approximately \$5.7 billion.

**Generator Performance**

- **Forced Outage Rates.** Average PJM EFORD increased from 7.2 percent in 2010 to 7.9 percent in 2011.<sup>77</sup>

**Figure 6 Trends in the PJM equivalent demand forced outage rate (EFORD): Calendar years 2007 to 2011**

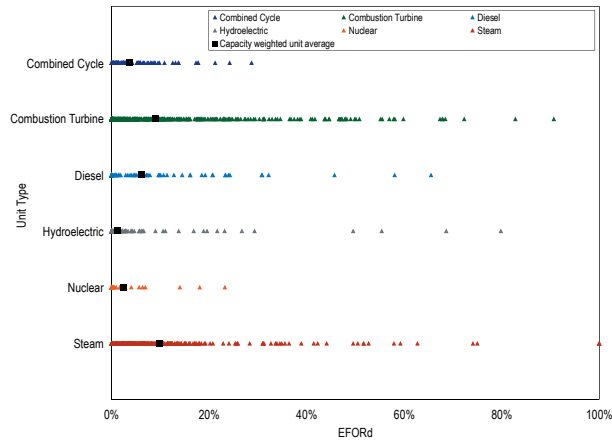


76 1999-2006 capacity prices are CCM combined market, weighted average prices. The 2007 capacity price is a combined CCM/RPM weighted average price. The 2008-2014 capacity prices are RPM weighted average prices. The CCM data points plotted are cleared MW weighted average prices for the daily and monthly markets by delivery year. The RPM data points plotted are RPM resource clearing prices.

77 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 the RPM. Data is for the twelve months ending December 31, as downloaded from the PJM GADS database on January 26, 2012. 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.

75 For a more detailed analysis of the 2013/2014 RPM Base Residual Auction, 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](http://www.monitoringanalytics.com/reports/Reports/2010/Analysis_of_2013_2014_RPM_Base_Residual_Auction_20090920.pdf)> (September 20, 2010).

**Figure 7 PJM 2011 distribution of EFORd data by unit type**



- **Generator Performance Factors.** The PJM aggregate equivalent availability factor decreased from 84.9 percent in 2010 to 83.7 percent in 2011.
- **Outages Deemed Outside Management Control (OMC).** According to North American Electric Reliability Corporation (NERC) criteria, an outage may be classified as an OMC outage if the generating unit outage was caused by other than failure of the owning company's equipment or other than the failure of the practices, policies and procedures of the owning company. In 2011, 11.6 percent of forced outages were classified as OMC outages. OMC outages are excluded from the calculation of the forced outage rate, termed the XEFORd, used to calculate the unforced capacity that must be offered in the PJM Capacity Market.

## Section 4 Conclusion

The Capacity Market is, by design, always tight in the sense that total supply is generally only slightly larger than demand. The demand for capacity includes expected peak load plus a reserve margin. Thus, the reliability goal is to have total supply equal to, or slightly above, the demand for capacity. The market may be long at times, but that is not the equilibrium state. Capacity in excess of demand is not sold and, if it does not earn adequate revenues in other markets, will retire. Demand is almost entirely inelastic, because the market rules require loads to purchase their share of the system capacity requirement. The result is that any supplier that owns more capacity than the difference

between total supply and the defined demand is pivotal and has market power.

In other words, the market design for capacity leads, almost unavoidably, to structural market power. Given the basic features of market structure in the PJM Capacity Market, including significant market structure issues, inelastic demand, tight supply-demand conditions, the relatively small number of nonaffiliated LSEs and supplier knowledge of aggregate market demand, the MMU concludes that the potential for the exercise of market power continues to be high. Market power is and will remain endemic to the existing structure of the PJM Capacity Market. This is not surprising in that the Capacity Market is the result of a regulatory/administrative decision to require a specified level of reliability and the related decision to require all load serving entities to purchase a share of the capacity required to provide that reliability. It is important to keep these basic facts in mind when designing and evaluating capacity markets. The Capacity Market is unlikely ever to approach the economist's view of a competitive market structure in the absence of a substantial and unlikely structural change that results in much more diversity of ownership.

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, by market shares and by the Herfindahl-Hirschman Index (HHI), but no exercise of market power in the PJM Capacity Market in calendar year 2011. 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 calendar year 2011.



The MMU has also identified serious market design issues with RPM and the MMU has made specific recommendations to address those issues.<sup>78,79,80,81</sup> In 2011, the MMU prepared a number of RPM-related reports and testimony, shown in Table 13.

**Table 13 RPM Related MMU Reports**

Date	Name
January 6, 2011	Analysis of the 2011/2012 RPM First Incremental Auction <a href="http://www.monitoringanalytics.com/reports/Reports/2011/Analysis_of_2011_2012_RPM_First_Incremental_Auction_20110106.pdf">http://www.monitoringanalytics.com/reports/Reports/2011/Analysis_of_2011_2012_RPM_First_Incremental_Auction_20110106.pdf</a>
January 6, 2011	Impact of New Jersey Assembly Bill 3442 on the PJM Capacity Market <a href="http://www.monitoringanalytics.com/reports/Reports/2011/NJ_Assembly_3442_Impact_on_PJM_Capacity_Market.pdf">http://www.monitoringanalytics.com/reports/Reports/2011/NJ_Assembly_3442_Impact_on_PJM_Capacity_Market.pdf</a>
January 14, 2011	Analysis of the 2011/2012 and 2012/2013 ATSI Integration Auctions <a href="http://www.monitoringanalytics.com/reports/Reports/2011/Analysis_of_2011_2012_and_2012_2013_ATSI_Integration_Auctions_20110114.pdf">http://www.monitoringanalytics.com/reports/Reports/2011/Analysis_of_2011_2012_and_2012_2013_ATSI_Integration_Auctions_20110114.pdf</a>
January 28, 2011	Impact of Maryland PSC's Proposed RFP on the PJM Capacity Market <a href="http://www.monitoringanalytics.com/reports/Reports/2011/IMM_Comments_to_MDPSC_Case_No_9214_20110128.pdf">http://www.monitoringanalytics.com/reports/Reports/2011/IMM_Comments_to_MDPSC_Case_No_9214_20110128.pdf</a>
February 1, 2011	Preliminary Market Structure Screen results for the 2014/2015 RPM Base Residual Auction <a href="http://www.monitoringanalytics.com/reports/Reports/2011/PMSS_Results_20142015_20110201.pdf">http://www.monitoringanalytics.com/reports/Reports/2011/PMSS_Results_20142015_20110201.pdf</a>
March 4, 2011	IMM Comments re MOPR Filing Nos. EL11-20, ER11-2875 <a href="http://www.monitoringanalytics.com/reports/Reports/2011/IMM_Comments_EL11-20-000_ER11-2875-000_20110304.pdf">http://www.monitoringanalytics.com/reports/Reports/2011/IMM_Comments_EL11-20-000_ER11-2875-000_20110304.pdf</a>
March 21, 2011	IMM Answer and Motion for Leave to Answer re: MOPR Filing Nos. EL11-20, ER11-2875 <a href="http://www.monitoringanalytics.com/reports/Reports/2011/IMM_Answer_and_Motion_for_Leave_to_Answer_EL11-20-000_ER11-2875-000_20110321.pdf">http://www.monitoringanalytics.com/reports/Reports/2011/IMM_Answer_and_Motion_for_Leave_to_Answer_EL11-20-000_ER11-2875-000_20110321.pdf</a>
June 2, 2011	IMM Protest re: PJM Filing in Response to FERC Order Regarding MOPR No. ER11-2875-002 <a href="http://www.monitoringanalytics.com/reports/Reports/2011/IMM_Protest_ER11-2875-002.pdf">http://www.monitoringanalytics.com/reports/Reports/2011/IMM_Protest_ER11-2875-002.pdf</a>
June 17, 2011	IMM Comments re: In the Matter of the Board's Investigation of Capacity Procurement and Transmission Planning No. E011050309 <a href="http://www.monitoringanalytics.com/reports/Reports/2011/IMM_Comments_NJ_EO_11050309_20110617.pdf">http://www.monitoringanalytics.com/reports/Reports/2011/IMM_Comments_NJ_EO_11050309_20110617.pdf</a>
June 27, 2011	Units Subject to RPM Must Offer Obligation <a href="http://www.monitoringanalytics.com/reports/Market_Messages/Messages/IMM_Units_Subject_to_RPM_Must_Offer_Obligation_20110627.pdf">http://www.monitoringanalytics.com/reports/Market_Messages/Messages/IMM_Units_Subject_to_RPM_Must_Offer_Obligation_20110627.pdf</a>
August 29, 2011	Post Technical Conference Comments re: PJM's Minimum Offer Price Rule Nos. ER11-2875-001, 002, and EL11-20-001 <a href="http://www.monitoringanalytics.com/reports/Reports/2011/IMM_Post_Technical_Conference_Comments_ER11-2875_20110829.pdf">http://www.monitoringanalytics.com/reports/Reports/2011/IMM_Post_Technical_Conference_Comments_ER11-2875_20110829.pdf</a>
September 15, 2011	IMM Motion for Leave to Answer and Answer re: MMU Role in MOPR Review No. ER11-2875-002 <a href="http://www.monitoringanalytics.com/reports/Reports/2011/IMM_Motion_for_Leave_to_Answer_and_Answer_ER11-2875-002_20110915.pdf">http://www.monitoringanalytics.com/reports/Reports/2011/IMM_Motion_for_Leave_to_Answer_and_Answer_ER11-2875-002_20110915.pdf</a>
November 22, 2011	Generator Capacity Resources in PJM Region Subject to "Must Offer" Obligation for the 2012/2013, 2013/2014 and 2014/2015 Delivery Years <a href="http://www.monitoringanalytics.com/reports/Market_Messages/Messages/RPM_Must_Offer_Obligation_20111123.pdf">http://www.monitoringanalytics.com/reports/Market_Messages/Messages/RPM_Must_Offer_Obligation_20111123.pdf</a>
January 9, 2012	IMM Comments re:MOPR Compliance No. ER11-2875-003 <a href="http://www.monitoringanalytics.com/reports/Reports/2012/IMM_Comments_ER11-2875-003_20120109.pdf">http://www.monitoringanalytics.com/reports/Reports/2012/IMM_Comments_ER11-2875-003_20120109.pdf</a>
January 20, 2012	IMM Testimony re: Review of the Potential Impact of the Proposed Capacity Additions in the State of Maryland's Joint Petition for Approval of Settlement MD PSC Case No. 9271 <a href="http://www.monitoringanalytics.com/reports/Reports/2012/IMM_Testimony_MD_PSC_9271.pdf">http://www.monitoringanalytics.com/reports/Reports/2012/IMM_Testimony_MD_PSC_9271.pdf</a>
January 20, 2012	IMM Comments re: Capacity Procurement RFP MD PSC Case No. 9214 <a href="http://www.monitoringanalytics.com/reports/Reports/2012/IMM_Comments_MD_PSC_9214.pdf">http://www.monitoringanalytics.com/reports/Reports/2012/IMM_Comments_MD_PSC_9214.pdf</a>
February 7, 2012	Preliminary Market Structure Screen results for the 2015/2016 RPM Base Residual Auction <a href="http://www.monitoringanalytics.com/reports/Reports/2012/PMSS_Results_20152016_20120207.pdf">http://www.monitoringanalytics.com/reports/Reports/2012/PMSS_Results_20152016_20120207.pdf</a>
February 15, 2012	RPM-ACR and RPM Must Offer Obligation FAQs <a href="http://www.monitoringanalytics.com/Tools/docs/RPM-ACR_FAQ_RPM_Must_Offer_Obligation_20120215.pdf">http://www.monitoringanalytics.com/Tools/docs/RPM-ACR_FAQ_RPM_Must_Offer_Obligation_20120215.pdf</a>
February 17, 2012	IMM Motion for Clarification re: Minimum Offer Price Rule Revision Nos.ER11-2871-000, -001 and -002, EL11-20-000 and -001 <a href="http://www.monitoringanalytics.com/reports/Reports/2012/IMM_Motion_for_Clarification_ER11-2875_EL-20_20120217.pdf">http://www.monitoringanalytics.com/reports/Reports/2012/IMM_Motion_for_Clarification_ER11-2875_EL-20_20120217.pdf</a>

78 See "Analysis of the 2011/2012 RPM Auction Revised" <<http://www.monitoringanalytics.com/reports/Reports/2008/20081002-review-of-2011-2012-rpm-auction-revised.pdf>> (October 1, 2008).

79 See "Analysis of the 2012/2013 RPM Base Residual Auction" <[http://www.monitoringanalytics.com/reports/Reports/2009/Analysis\\_of\\_2012\\_2013\\_RPM\\_Base\\_Residual\\_Auction\\_20090806.pdf](http://www.monitoringanalytics.com/reports/Reports/2009/Analysis_of_2012_2013_RPM_Base_Residual_Auction_20090806.pdf)> (August 6, 2009)

80 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](http://www.monitoringanalytics.com/reports/Reports/2010/Analysis_of_2013_2014_RPM_Base_Residual_Auction_20090920.pdf)> (September 20, 2010).

81 See "IMM Response to Maryland PSC re: Reliability Pricing Model and the 2013/2014 Delivery Year Base Residual Auction Results" <[http://www.monitoringanalytics.com/reports/Reports/2010/IMM\\_Response\\_to\\_MDPSC\\_RPM\\_and\\_2013-2014\\_BRA\\_Results.pdf](http://www.monitoringanalytics.com/reports/Reports/2010/IMM_Response_to_MDPSC_RPM_and_2013-2014_BRA_Results.pdf)> (October 4, 2010).

## Section 5, Demand Response

### Highlights

- In 2011, the total MWh of load reduction under the Economic Load Response Program decreased by 57,288 MWh compared to the same period in 2010, from 74,070 MWh in 2010 to 16,782 MWh in 2011, a 77 percent decrease. Total payments under the Economic Program decreased by \$1,080,438, from \$3,088,049 in 2010 to \$2,007,612 in 2011, a 35 percent decrease. (See Volume II, page 131)
- In calendar year 2011, total capacity payments to demand response resources under the PJM Load Management (LM) Program, which integrated Emergency Load Response Resources into the Reliability Pricing Model, decreased by \$25.2 million, or 4.9 percent, compared to the same period in 2010, from \$512 million in 2010 to \$487 million in 2011. (See Volume II, page 133)

### Recommendations

- The MMU recommends elimination of the Limited and Extended Summer Demand Response products from the capacity market. All products competing in the capacity market should be required to be available to perform when called for every hour of the year.
- The MMU recommends that PJM continue to implement subzonal dispatch for Demand Response products and develop a plan to implement nodal dispatch for all demand resources.
- The MMU recommends that changes be made to simplify and improve the Emergency Demand Response (DR) program. The MMU recommends that the option to specify a minimum dispatch price under the Emergency Program Full option be eliminated and that participating resources receive the hourly real-time LMP less any generation component of their retail rate. The MMU also recommends that the Emergency Program Energy Only option be eliminated because the opportunity to receive the appropriate energy market incentive is already provided in the Economic Program.

The MMU recommends that there be improvement in measurement and verification methods implemented in order to ensure the credibility of PJM demand-side

programs. These could take the form of improvements in the CBL calculation and/or improvements in the verification and customer documentation of load reducing activities. PJM has implemented or plans to implement changes to the CBL calculation that should improve measurement and verification for many customers.

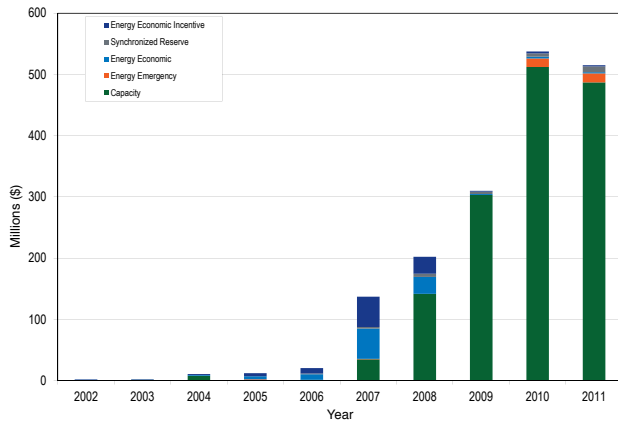
### Overview

- **Demand-Side Response Activity.** In calendar year 2011, the total MWh of load reduction under the Economic Load Response Program decreased by 57,288 MWh compared to the same period in 2010, from 74,070 MWh in 2010 to 16,782 MWh in 2011, a 77 percent decrease. Total payments under the Economic Program decreased by \$1,080,438, from \$3,088,049 in 2010 to \$2,007,612 in 2011, a 35 percent decrease.

Settled MWh and credits were lower in 2011 compared to 2010, and there were generally fewer settlements submitted compared to the same period in 2010. Participation levels since 2008 have generally been lower compared to prior years due to a number of factors, including lower price levels, lower load levels and improved measurement and verification. On the peak load day for 2011 (July 21, 2011), there were 2,041.5 MW registered in the Economic Load Response Program.

Since the implementation of the RPM design on June 1, 2007, the capacity market has become the primary source of revenue to participants in PJM demand side programs. In 2011, Load Management (LM) Program revenues decreased by \$25.2 million or 4.9 percent, from \$512 million to \$487 million. Through calendar year 2011, Synchronized Reserve credits for demand side resources increased by \$4.1 million compared to the same period in 2010, from \$5.3 million in 2010 to \$9.4 million in 2011.

**Figure 8 Demand Response revenue by market: Calendar years 2002 through 2011**



- Locational Dispatch of Demand-Side Resources.** PJM dispatches demand-side resources on a subzonal basis when appropriate. The disconnect created by the fact that CSPs are still permitted to aggregate customers on a zonal basis is being addressed through the stakeholder process. More locational deployment of demand-side resources improves efficiency in a nodal market where demand side resources should be dispatched consistent with transmission constraints.

## Section 5 Conclusions

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.

Most end use customers pay a fixed retail rate with no direct relationship to the hourly wholesale market LMP. End use customers pay load serving entities (LSEs)

an annual amount designed to recover, among other things, the total cost of wholesale power for the year.<sup>82</sup> End use customers paying fixed retail rates do not face even the hourly zonal average LMP. Thus, it would be a substantial step forward for customers to face the hourly zonal average price. But the actual market price of energy and the appropriate price signal for end use customers is the nodal locational marginal price. Within a zone, the actual costs of serving load, as reflected in the nodal hourly LMP, can vary substantially as a result of transmission constraints. A customer on the high price side of a constraint would have a strong incentive to add demand side resources if they faced the nodal price while that customer currently has an incentive to use more energy than is efficient, under either a flat retail rate or a rate linked to average zonal LMP. The nodal price provides a price signal with the actual locational marginal value of energy. In order to achieve the full benefits of nodal pricing on the supply and the demand side, load should ultimately pay nodal prices. However, a transition to nodal pricing could have substantial impacts and therefore must be managed carefully.

Today, most end use customers do not face the market price of energy, that is the locational marginal price of energy (LMP), or the market price of capacity, the locational capacity market clearing price. Most end use customers pay a fixed retail rate with no direct relationship to the hourly wholesale market LMP, either on an average zonal or on a nodal basis. This results in a market failure because when customers do not know the market price and do not pay the market price, the behavior of those customers is inconsistent with the market value of electricity. This market failure does not imply that PJM markets have failed. This market failure means that customers do not pay the actual hourly locational cost of energy as a result of the disconnect between wholesale markets and retail pricing. When customers pay a price less than the market price, customers will tend to consume more than if they faced the market price and when customers pay a price greater than the market price, customers will tend to consume less than they would if they faced the market price. This market failure is relevant to the wholesale power market because the actual hourly locational price of power used by customers is determined by the wholesale

<sup>82</sup> In PJM, load pays the average zonal LMP, which is the weighted average of the actual nodal locational marginal price. While individual customers have the option to pay nodal LMP, very few customers do so.

power market, regardless of the average price actually paid by customers. The transition to a more functional demand side requires that the default energy price for all customers be the day-ahead or real-time hourly locational marginal price (LMP) and the locational clearing price of capacity. While the initial default energy price could be the average LMP, the transition to nodal LMP pricing should begin.

PJM's Economic Load Response Program (ELRP) is designed to address this market failure by attempting to replicate the price signal to customers that would exist if customers were exposed to the real-time wholesale zonal price of energy and by providing settlement services to facilitate the participation of third party Curtailment Service Providers (CSPs) in the market.<sup>83</sup> In PJM's Economic Load Response Program, participants have the option to receive credits for load reductions based on a more locationally defined pricing point than the zonal LMP. However, less than one percent of participants have taken this option while almost all participants received credits based on the zonal average LMP. PJM's proposed PRD program does incorporate some aspects of nodal pricing, although the link between the nodal wholesale price and the retail price is extremely attenuated.

PJM's Load Management (LM) Program in the RPM market also attempts to replicate the price signal to customers that would exist if customers were exposed to the locational market price of capacity. The PJM market design also creates the opportunity for demand resources to participate in ancillary services markets.<sup>84</sup>

PJM's demand side programs, by design, provide a work around for end use customers that are not otherwise exposed to the incremental, locational costs of energy and capacity. They should be understood as one relatively small part of a transition to a fully functional demand side for its markets. The complete transition to a fully functional demand side will require explicit agreement and coordination among the Commission, state public utility commissions and RTOs/ISOs.

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, particularly in the Emergency Program which consists entirely of capacity resources, are not adequate to determine and quantify deliberate actions taken to reduce consumption.

<sup>83</sup> While the primary purpose of the ELRP is to replicate the hourly zonal price signal to customers on fixed retail rate contracts, customers with zonal or nodal hourly LMP contracts are currently eligible to participate in the DA scheduling and the PJM dispatch options of the Program.

<sup>84</sup> See the 2011 State of the Market Report for PJM, Volume II, Section 9, "Ancillary Service Markets."

## Section 6, Net Revenue

### Highlights

- Net revenues are significantly affected by fuel prices, energy prices and capacity prices. The combination of lower energy prices, lower gas prices and higher coal prices resulted in higher energy revenues for the new entrant CT and CC unit in most zones and lower energy net revenues for the new entrant coal unit in all zones in 2011. However, revenue from the capacity market was lower in 2011, which affected total net revenues for all units. Total new entrant CT net revenue decreased in 2011 in all but five zones. Total new entrant CC net revenue increased in all but five zones. Total new entrant coal unit net revenue was lower in all zones except AEP. (See Volume II, page 147)
- The MMU estimates that there are 5,764 MW of RPM coal capacity at risk of retirement. Capacity at risk of retirement includes units that did not cover their avoidable costs in 2011 or would not be able to cover the cost of installing MATS compliant environmental controls, excludes units that have started the deactivation process or are expected to request deactivation, and excludes FRR capacity. (See Volume II, page 157)

### Recommendations

- There are no recommendations in Section 6.

### Overview

#### Net Revenue

- **Net Revenue Adequacy.** Net revenue is the contribution to total fixed costs received by generators from PJM Energy, Capacity and Ancillary Service Markets and from the provision of black start and reactive services. Net revenue is the amount that remains, after short run variable costs have been subtracted from gross revenue, to cover total fixed costs which include a return on investment, depreciation, taxes and fixed operation and maintenance expenses.

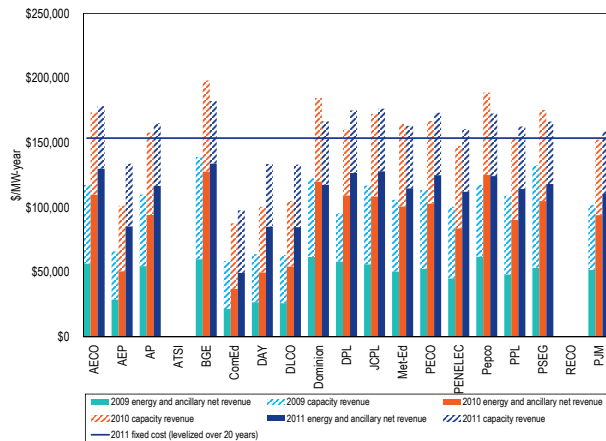
The adequacy of net revenue can be assessed both by comparing net revenue to total fixed costs and by comparing net revenue to avoidable costs. The comparison of net revenue to total fixed costs is an indicator of the incentive to invest in new and

existing units. The comparison of net revenue to avoidable costs for both hypothetical new entrant units and for existing units is an indicator of the extent to which the revenues from PJM markets provide sufficient incentive for continued operations in PJM Markets.

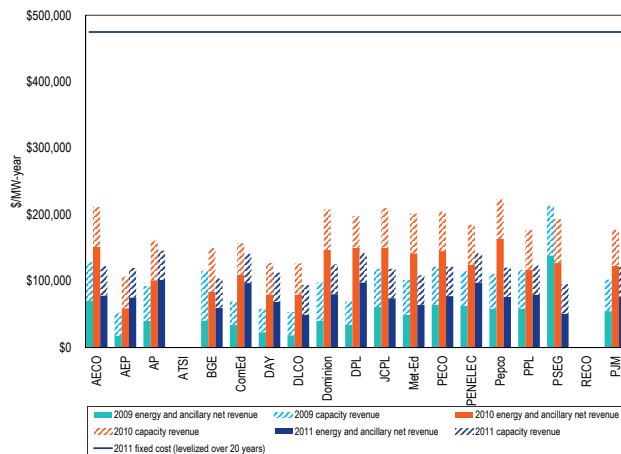
- **Net Revenue and Total Fixed Costs.** When compared to total fixed costs, net revenue is an indicator of generation investment profitability and thus is a measure of overall market performance as well as a measure of the incentive to invest in new generation and in existing generation to serve PJM markets. Net revenue is the contribution to total fixed costs received by generators from all PJM markets. Although it can be expected that in the long run, in a competitive market, net revenue from all sources will cover the total fixed costs of investing in new generating resources, including a competitive return on investment, when there is a market based need, actual results are expected to vary from year to year. Wholesale energy markets, like other markets, are cyclical. When the markets are long, prices will be lower and when the markets are short, prices will be higher.

Net revenues are significantly affected by fuel prices, energy prices and capacity prices. Gas prices decreased on average by 10 percent and coal prices increased on average by 19 percent in 2011. The combination of lower energy prices, lower gas prices and higher coal prices resulted in higher energy revenues for the new entrant CT and CC unit in most zones and lower energy net revenues for the new entrant coal unit in all zones in 2011. However, revenue from the capacity market was lower in 2011, which affected total net revenues for all units. Total new entrant CT net revenue decreased in 2011 in all but five zones. Total new entrant CC net revenue increased in all but five zones. Total new entrant coal unit net revenue was lower in all zones except AEP.

**Figure 9 New entrant CC net revenue and 20-year levelized fixed cost (Dollars per installed MW-year)**



**Figure 10 New entrant CP net revenue and 20-year levelized fixed cost (Dollars per installed MW-year)**



- Actual Net Revenue and Avoidable Costs.** Avoidable costs are the costs which must be paid each year in order to keep a unit operating. Avoidable costs are less than total fixed costs, which include the return on and of capital, and more than marginal costs, which are the short run incremental costs of producing energy. It is rational for an owner to continue to operate a unit if it is covering its avoidable costs and therefore contributing to covering fixed costs. It is not rational for an owner to continue to operate a unit if it is not covering and not expected to cover its avoidable costs. As a general matter, under those conditions, retirement of the unit is the logical option. The analysis, which compares net revenues to avoidable costs, is a

measure of the extent to which units in PJM may be at risk of retirement.

It is not rational for an owner to invest in environmental controls if a unit is not covering and is not expected to cover its avoidable costs plus the annualized fixed costs of the investment. As a general matter, under those conditions, retirement of the unit is the logical option. The analysis, which compares net revenues to avoidable costs plus the annualized fixed costs of investments in environmental controls where relevant, is a measure of the extent to which such units in PJM may be at risk of retirement.

For both the CT and CC technologies, as well as for the gas-fired and oil-fired steam technologies, RPM revenue has provided a required supplemental revenue stream to incent continued operations in PJM for units that do not recover 100 percent of fixed costs through energy market revenue. Nuclear and run of river hydro technologies generally recover avoidable costs entirely from the energy market.

The coal plant technologies have higher avoidable costs and are more dependent on energy market net revenues than the CT and CC technologies. The total installed capacity of sub-critical coal and supercritical coal units that did not cover avoidable costs from energy revenues plus capacity revenues in 2011 was 5,503 MW. Generally, coal units that did not recover avoidable costs tended to be smaller and less efficient, facing higher operating costs and higher avoidable costs.

Other coal plants received significant energy market revenues but had made project investments associated with maintaining or improving reliability or environmental regulations, in which case, failure to cover avoidable costs, as defined in RPM, may be only a failure to recover the annual project recovery rate. If project costs are sunk, or if the project life is longer than the PJM defined recovery period for the calculation of the avoidable cost rate, it is rational to bid units below avoidable costs, as defined in RPM. In either case, these units may be at a lower risk of retirement than units not recovering avoidable costs excluding capital recovery, as they may stay in service for the duration of the project life.

Coal plants also face a higher risk of capital expenditures to comply with environmental regulations. The total installed capacity of sub-critical coal and supercritical coal units that do not have NO<sub>x</sub>, SO<sub>2</sub>, or particulate controls in place is 17,104 MW. Of the capacity lacking NO<sub>x</sub>, SO<sub>2</sub>, or particulate controls, 83 percent is associated with plants older than 40 years.

## Section 6 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.

A capacity market is a formal mechanism, with both administrative and market-based components, used to allocate the costs of maintaining the level of capacity required to maintain the reliability target. A capacity market is an explicit mechanism for valuing capacity and is preferable to nonmarket and nontransparent mechanisms for that reason.

The historical level of net revenues in PJM markets was not the result of the \$1,000-per-MWh offer cap, of local market power mitigation, or of a basic incompatibility between wholesale electricity markets and competition. Competitive markets can, and do, signal scarcity and

surplus conditions through market clearing prices. Nonetheless, in PJM as in other wholesale electric power markets, the application of reliability standards means that scarcity conditions in the Energy Market occur with reduced frequency. Traditional levels of reliability require units that are only directly used and priced under relatively unusual load conditions. Thus, the Energy Market alone frequently does not directly compensate the resources needed to provide for reliability.

PJM's RPM is an explicit effort to address these issues. RPM is a capacity market design intended to send supplemental signals to the market based on the locational and forward-looking need for generation resources to maintain system reliability in the context of a long-run competitive equilibrium in the Energy Market. The PJM Capacity Market is explicitly designed to provide revenue adequacy and the resultant reliability.

The net revenue results illustrate some fundamentals of the PJM wholesale power market. CTs are generally the highest incremental cost units and therefore tend to be marginal in the energy market and set prices when they run. When this occurs, CT energy market net revenues tend to be low and there is little contribution to fixed costs. High demand hours result in less efficient CTs setting prices, which results in higher net revenues for more efficient CTs and other inframarginal units.

The PJM Capacity Market is explicitly designed to provide revenue adequacy and the resultant reliability. In the PJM design, the capacity market provides a significant stream of revenue that contributes to the recovery of total costs for new and existing peaking units that may be needed for reliability during years in which energy net revenues are not sufficient. The capacity market is also a significant source of net revenue to cover the fixed costs of investing in new intermediate and base load units, although capacity revenues are a larger part of net revenue for peaking units. However, when the actual fixed costs of capacity increase rapidly, or, when the energy net revenues used as the offset in determining capacity market prices are higher than actual energy net revenues, there is a corresponding lag in capacity market prices which will tend to lead to an under recovery of the fixed costs of CTs. The reverse can also happen, leading to an over recovery of the fixed costs of CTs, although it has happened less frequently in PJM markets.

## Section 7, Environmental and Renewables

### Highlights

- The EPA issued the Mercury Air Toxics Rule December 16, 2011, which will require significant investments in control technology for Mercury and other pollutants, effective April 16, 2015. (See Volume II, page 163)
- Generation from wind units increased from 9,688.2 GWh in 2010 to 11,561.1 GWh in 2011, an increase of 19.3 percent. Generation from solar units increased from 5.7 GWh in 2010 to 55.7 GWh in 2011, an increase of 872.5 percent. (See Volume II, page 173)
- At the end of 2011, the Cross-State Air Pollution Rule was subject to a stay pending further action on appeal, resulting in the reinstatement of the Clean Air Interstate Rule for 2012. (See Volume II, page 161)
- Emission prices declined in calendar year 2011 compared to calendar year 2010. NO<sub>x</sub> prices declined 64.3 percent in 2011 compared to 2010, and SO<sub>2</sub> prices declined 87.3 percent in 2011 compared to 2010. RGGI CO<sub>2</sub> prices declined by 4.6 percent in 2011 compared to 2010. (See Volume II, page 169)
- The price of RGGI CO<sub>2</sub> allowances remained at or near the floor price of \$1.89 during 2011, and as of January 1, 2012, the state of New Jersey will no longer be participating in the RGGI program. (See Volume II, page 168)

### Recommendations

- The MMU recommends that renewable energy credit markets based on state renewable portfolio standards be brought into PJM markets as they are an increasingly important component of the wholesale energy market.

### Overview

#### Federal Environmental Regulation

- **EPA Mercury and Air Toxics Standards Rule.**<sup>85</sup> On December 16, 2011, the 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. The rule establishes a compliance deadline of April 16, 2015. A source may obtain an extension for up to one additional year where necessary for the installation of controls. The CAA defines MACT as the average emission rate of the best performing 12 percent of existing resources (or the best performing five sources for source categories with less than 30 sources). In addition, in a related EPA rule issued on the same date regarding New Source Performance Standards (NSPS), a rule also referred to as part of MATS, the EPA requires new electric generating units constructed after May 3, 2011, to comply with amended emission standards for SO<sub>2</sub>, NO<sub>x</sub> and filterable particulate matter.

- **Cross-State Air Pollution Rule.** On July 6, 2011, the U.S. Environmental Protection Agency (EPA) finalized the Cross-State Air Pollution Rule (CSAPR), a rule that requires specific states in the eastern and central United States to reduce power plant emissions of SO<sub>2</sub> and NO<sub>x</sub> that cross state lines and contribute to ozone and fine particle pollution in other states, to levels consistent with the 1997 ozone and fine particle and 2006 fine particle National Ambient Air Quality Standards (NAAQS). CSAPR will cover 28 states, including all of the PJM states except Delaware, and also excepting the District of Columbia. This rule replaces a 2005 rule known as the Clean Air Interstate Rule (CAIR), which has been in effect temporarily while the EPA developed a successor rule responding to a Federal Court of Appeals order directing revisions compliant with the requirements of the CAA. CSAPR was expected to become effective January 1, 2012, but a stay issued on December 30, 2011, by the Federal Court of Appeals considering petitions to review CSAPR, prevents such implementation pending a decision on the merits. CAIR will remain in effect pending such resolution.
- **National Emission Standards for Reciprocating Internal Combustion Engines (RICE).** The EPA recently issued rules regulating owners and operators of wide variety of stationary reciprocating internal combustion engines (RICE). RICE include certain types of electrical generation facilities like

<sup>85</sup> MATS replaces the Clean Air Mercury Rule (CAMR). It has been widely known previously as the "HAP" or "Utility MACT" rule.



diesel engines typically used for backup, emergency or supplemental power. RICE include facilities located behind the meter and often used to provide demand side resources in the RPM. The RICE rules apply to emissions such as formaldehyde, acrolein, acetaldehyde, methanol, CO, NO<sub>x</sub>, volatile organic compounds (VOCs), and particulate matter.

Several curtailment service providers (CSPs) reached a settlement with the EPA regarding their appeals in Federal Court, resulting in a commitment by the EPA to file revised rules that would accommodate participation by RICE in emergency demand response programs administered by Independent System Operators. The Market Monitoring Unit objected to the settlement, explaining that it did not enhance clean air, participation by demand side resources in the organized markets nor reliability.<sup>86</sup> If approved, the settlement would require the EPA Administrator to take final action on the rules substantially consistent with the settlement by December 14, 2012.

- **EPA Greenhouse Gas Tailoring Rule.** On May 13, 2010, the EPA issued a rule regulating CO<sub>2</sub> and other greenhouse gas emissions under the existing framework of new source review (NSR) and prevention of significant deterioration (PSD). As a result, new or modified units must install or implement the best available control technology (BACT). State environmental regulators determine BACT project by project, with guidance from the EPA.

## State Environmental Regulation

- **NJ High Electric Demand Day (HEDD) Rule.** New Jersey has addressed the issue of NO<sub>x</sub> 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<sub>x</sub> emissions on HEDD. New Jersey’s HEDD rule,<sup>87</sup> which became effective May 19, 2009, applies to HEDD units, which include units that have a NO<sub>x</sub> emissions rate on HEDD equal to or exceeding 0.15 lbs/MMBTU

and lack identified emission control technologies.<sup>88</sup> New Jersey’s HEDD rule will be implemented in two phases. Through calendar years 2009–2014, HEDD unit owners/operators must submit annual performance reports and are subject to various behavioral requirements. After May 1, 2015, new, reconstructed or modified turbines must comply with certain technology standards. Owners/operators of existing HEDD units were each required to submit by May 1, 2010 and update annually a 2015 HEDD Emission Limit Achievement Plan, describing how each owner/operator intended to comply with the 2015 HEDD maximum NO<sub>x</sub> emission rates.

- **Regional Greenhouse Gas Initiative (RGGI).** The Regional Greenhouse Gas Initiative (RGGI) is a cooperative effort by Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont to cap CO<sub>2</sub> emissions from power generation facilities. After December 31, 2011, the State of New Jersey will no longer participate in the RGGI program. Auction prices in 2011 for the 2009–2011 compliance period were \$1.89 throughout the year, which was the price floor for 2011.

## Renewables and Emissions Controls in PJM Markets

Due to environmental regulations and agreements to limit emissions, many PJM units burning fossil fuels have installed emission control technology. Environmental regulations may affect decisions about emission control investments in existing units, investment in new units and decisions to retire units lacking emission controls. At the end of 2011, 64.5 percent of coal steam MW’s had some type of FGD (flue-gas desulfurization) technology to reduce SO<sub>2</sub> emissions from coal steam units, while 98.0 percent of coal steam MW’s had some type of particulate control. NO<sub>x</sub> emission controlling technology is used by nearly all fossil fuel unit types, and 90.4 percent of fossil fuel fired capacity in PJM has NO<sub>x</sub> emission control technology in place.

Many PJM jurisdictions have enacted legislation to require that a defined percentage of utilities’ load be served by renewable resources, for which there are

<sup>86</sup> See *In the Matter of: EnerNOC, Inc., et al.*, Comments of the Independent Market Monitor for PJM, Docket No. EPA-HQ-OGC-2011-1030 (February 16, 2012).

<sup>87</sup> N.J.A.C. § 7:27-19.

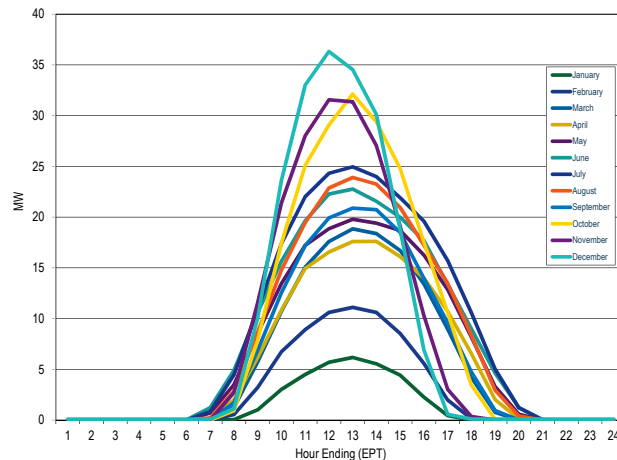
<sup>88</sup> CTs must have either water injection or Selective Catalytic Reduction (SCR) controls; steam units must have either an SCR or and Selective Non-Catalytic Reduction (SNCR).

many standards and definitions. These are typically known as Renewable Portfolio Standards, or RPS. As of 2011, Delaware, Illinois, Maryland, New Jersey, North Carolina, Ohio, Pennsylvania, and Washington D.C. had renewable portfolio standards, ranging from 0.02 percent of all load served in North Carolina, to 8.30 percent of all load served in New Jersey. Virginia has enacted a voluntary renewable portfolio standard. Kentucky and Tennessee have enacted no renewable portfolio standards.

Renewable energy credits give wind and solar resources the incentive to make negative price offers, as they offer a payment to renewable resources in addition to the wholesale price of energy. The out-of-market payments in the form of RECs and federal production tax credits mean these units have an incentive to generate MWh until the negative LMP is equal to the credit received for each MWh adjusted for any marginal costs. These subsidies affect the offer behavior of these resources in PJM markets.

access to a broad market and are priced competitively so as to reflect their market value. PJM markets can provide efficient price signals that permit valuation of resources with very different characteristics when they provide the same product.

**Figure 11 Average hourly real-time generation of solar units in PJM: Calendar year 2011**



## Section 7 Conclusion

Initiatives at both the Federal and state levels have an impact on the cost of energy and capacity in 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 could be used to incorporate renewable resource requirements to ensure that renewable resources have

## Section 8, Interchange Transactions Highlights

- On June 1, 2011 at 0100, the American Transmission Systems, Inc. (ATSI) Control Zone was integrated into PJM. As a result, the First Energy (FE) Interface and the MICHFE Interface Pricing Point were eliminated. (See Volume II, page 196)
- Real-time net exports increased to -9,761.8 GWh in 2011 from -9,661.0 GWh for the calendar year 2010. Day-ahead net imports in 2011 were 6,576.2 GWh compared to net exports of -6,470.0 GWh for the calendar year 2010. The primary reason that PJM became a net importer of energy in the Day-Ahead Market in 2011 was the significant increase in up-to congestion transactions and the fact that up-to congestion transactions were net imports for most of that period. (See Volume II, page 187)
- The direction of power flows was not consistent with real-time energy market price differences in 55 percent of hours at the border between PJM and MISO and in 48 percent of hours at the border between PJM and NYISO in 2011. (See Volume II, page 198)
- In 2011, net scheduled interchange was -7,072 GWh and net actual interchange was -7,576 GWh, a difference of 504 GWh or 7.1 percent, an increase from 5.2 percent for the calendar year 2010. While actual interchange exceeded scheduled interchange in 2011, the opposite was true in 2010. This difference is system inadvertent. The total inadvertent over the two year period including 2010 and 2011 was 1.1 percent. (See Volume II, page 208)
- PJM initiated 62 TLRs in 2011, a reduction from the 110 TLRs for the calendar year 2010. (See Volume II, page 211)
- The average daily volume of up-to congestion bids increased from 4,293 bids per day, for the period between March 1, 2009 through May 14, 2010, to 6,881 bids per day for the period between May 15, 2010 through September 16, 2010, to 26,303 bids per day for the period between September 17, 2010 and December 31, 2011. A significant increase in bid

volume occurred following the September 17, 2010, modification to the up-to congestion product that eliminated the requirement to procure transmission when submitting up-to congestion bids.<sup>89</sup> (See Volume II, page 212)

- Total uncollected congestion charges in 2011 were -\$20,955, compared to \$3.3 million for the calendar year 2010. Uncollected congestion charges are accrued when not willing to pay congestion transactions are not curtailed when congestion between the specified source and sink is present. Uncollected congestion charges also apply when there is negative congestion (when the LMP at the source is greater than the LMP at the sink) which was the case for the net uncollected congestion charges in 2011. (See Volume II, page 218)
- Balancing operating reserve credits are paid to importing dispatchable transactions (also known as real-time with price) as a guarantee of the transaction price. Dispatchable transactions are made whole when the hourly integrated LMP does not meet the specified minimum price offer in the hours when the transaction was active. In 2011, these balancing operating reserve credits were \$1.3 million, a decrease from \$23.0 million for the calendar year 2010. The reasons for the reduction in these balancing operating reserve credits were active monitoring by the MMU and the absence of any such dispatchable transactions after April, 2011. (See Volume II, page 221)

## Recommendations

- The MMU recommends that PJM modify a number of its transaction related rules to improve market efficiency, reduce operating reserves charges, reduce gaming opportunities and to make the markets more transparent.
  - The MMU recommends performing a regular assessment of the mappings of external balancing authorities associated with the interface pricing points, and modify as necessary to ensure that prices reflect the actual flows on the transmission system.

<sup>89</sup> In prior state of the market reports for PJM, the number of up-to congestion bids reported represented unique up-to congestion transaction IDs. The new totals represent the total hours of up-to congestion bids per day. For example, if a unique up-to congestion transaction ID was submitted for all 24 hours of the day, it was counted as one bid in previous reports, and now is counted as 24 bids. This is consistent with the reporting of increment offers and decrement bids.

- The MMU recommends that PJM monitor, and adjust as necessary, the weights applied to the components of the interfaces to ensure that the interface prices reflect ongoing changes in system conditions and that loop flows are accounted for on a dynamic basis.
- The MMU recommends that PJM modify the not willing to pay congestion product to address the issues of uncollected congestion charges. The MMU recommends charging market participants for any congestion incurred while such transactions are loaded, regardless of their election of transmission service, and restricting the use of not willing to pay congestion transactions to transactions at interfaces (wheeling transactions).
  - On April 12, 2011, the PJM Market Implementation Committee (MIC) endorsed the elimination of internal source and sink designations in both the Day-Ahead and Real-Time Energy Markets.<sup>90</sup> These modifications are currently being evaluated by PJM. It is expected that implementation of these changes will occur by the end of the second quarter 2012.
- The MMU recommends eliminating internal source and sink bus designations for external energy transactions in the Day-Ahead and Real-Time Energy Markets.
  - On April 12, 2011, the PJM Market Implementation Committee (MIC) endorsed the elimination of internal source and sink designations in both the Day-Ahead and Real-Time Energy Markets.<sup>91</sup> These modifications are currently being evaluated by PJM. It is expected that implementation of these changes will occur by the end of the second quarter 2012.
- The MMU recommends eliminating or modifying the dispatchable transaction product to reduce the amount of balancing operating reserve credits associated with the uneconomic scheduling of the product.
  - On May 10, 2011, the PJM Market Implementation Committee (MIC) endorsed the recommendation to incorporate the dispatchable transaction product into PJM's dispatch tool.<sup>92</sup> PJM stated that the inclusion of this product would require minimal effort, and could be implemented by the end of 2011 or early in the first quarter of 2012.
- The MMU recommends eliminating or modifying the up-to congestion transaction product to ensure that it pays appropriate operating reserve charges and has appropriate credit requirements.
  - At the PJM Market Implementation Committee, held on February 17, 2012, the PJM stakeholders agreed to form a task force to address up-to congestion issues.
- The MMU recommends that the Enhanced energy Scheduler (EES) application be modified to require that transactions be scheduled for a constant MW level over the entire 45 minutes as soon as possible. This business rule is currently in the PJM Manuals, but is not being enforced.<sup>93</sup>
- The MMU requests that, in order to permit a complete analysis of loop flow, FERC and NERC ensure that the identified data are made available to market monitors as well as other industry entities determined appropriate by FERC.
- On April 21, 2011, FERC issued a Notice of Proposed Rulemaking addressing the issues associated with access to loop flow data by the Commission staff and market monitors.<sup>94</sup> On June 27, 2011, the North American market monitors provided comments to the Notice of Proposed Rulemaking, supporting the consideration to making the complete electronic tagging data used to schedule the transmission of electric power in wholesale markets available to entities involved in market monitoring functions.<sup>95</sup> As of December 31, 2011, the Commission had not made a final decision.

<sup>90</sup> See "Meeting Minutes" Minutes from PJM's MIC meeting , <<http://www.pjm.com/~media/committees-groups/committees/mic/20110412/20110412-mic-minutes.ashx>>. (May 16, 2011)

<sup>91</sup> See "Meeting Minutes" Minutes from PJM's MIC meeting , <<http://www.pjm.com/~media/committees-groups/committees/mic/20110412/20110412-mic-minutes.ashx>>. (May 16, 2011)

<sup>92</sup> See "Meeting Minutes" Minutes from PJM's MIC meeting , <<http://www.pjm.com/~media/committees-groups/committees/mic/20110510/20110510-mic-minutes.ashx>>. (July 13, 2011)

<sup>93</sup> See "PJM Manual 41: Managing Interchange," Revision 03 (November 24, 2008), External Transaction Minimum Duration Requirement.

<sup>94</sup> See 135 FERC ¶ 61,052 (2011).

<sup>95</sup> See "Joint Comments of the North American Market Monitors." Docket No. RM11-12-000 (June 27, 2011)

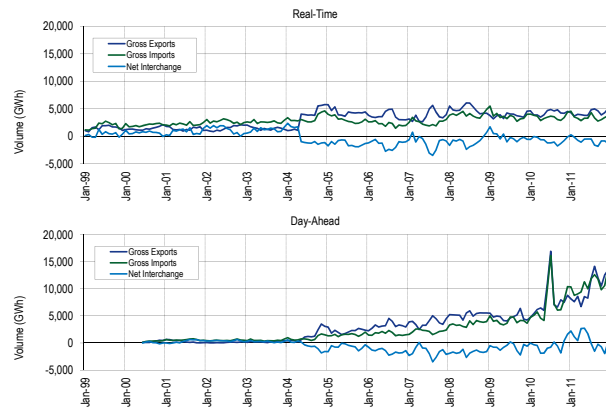
- The MMU recommends that PJM ensure that all the arrangements between PJM and other balancing authorities be reviewed, and modified as necessary to ensure consistency with basic market principles and that PJM not enter into any additional arrangements that are not consistent with basic market principles.
- In 2011, PJM and MISO hired an independent auditor to review and identify any areas of the market to market coordination process that were not conforming to the JOA, and to identify differing interpretations of the JOA between PJM and MISO that may lead to inconsistencies in the operation and settlements of the market to market process. The final report is expected to be completed and distributed early in the first quarter of 2012.

## Overview

### Interchange Transaction Activity

- **American Transmission System, Inc. (ATSI) Integration.** On June 1, 2011, at 0100, First Energy's American Transmission System, Inc. Control Zone was integrated into PJM. This integration eliminated the First Energy (FE) Interface, which reduced the total number of external PJM interfaces from 21 to 20 interfaces. The integration also resulted in the elimination of the MICHFE Interface Pricing Point, reducing the total number of real-time interface pricing points from 17 to 16.<sup>96</sup>
- **Aggregate Imports and Exports in the Real-Time Energy Market.** In 2011, PJM was a net importer of energy in the Real-Time Energy Market in January, and a net exporter of energy in the remaining months. In 2010, PJM was a net exporter of energy in the Real-Time Energy Market in all months. In the Real-Time Energy Market, monthly net interchange averaged -813.5 GWh compared to -805.1 GWh for the calendar year 2010.<sup>97</sup> Gross monthly import volumes averaged 3,437.8 GWh compared to 3,495.6 GWh in 2010 while gross monthly exports averaged 4,251.3 GWh compared to 4,300.6 GWh for the calendar year 2010.

**Figure 12 PJM real-time and day-ahead scheduled import and export transaction volume history: January 1999, through December, 2011**



- **Aggregate Imports and Exports in the Day-Ahead Energy Market.** In 2011, PJM was a net importer of energy in the Day-Ahead Energy Market from January through June and December, and a net exporter of energy in the remaining months. In 2010, PJM was a net importer of energy in the Day-Ahead Energy Market in August, November and December, and a net exporter of energy in the remaining months. In the Day-Ahead Energy Market, monthly net interchange averaged 548.0 GWh compared to -539.2 GWh for the calendar year 2010. Gross monthly import volumes averaged 10,751.5 GWh compared to 7,341.6 GWh for the calendar year 2010 while gross monthly exports averaged 10,203.5 GWh compared to 7,880.8 GWh for the calendar year 2010.

The primary reason that PJM became a net importer of energy in the Day-Ahead Market in 2011 was the significant increase in up-to congestion transactions and the fact that up-to congestion transactions were net imports for most of that period. In all months of 2011, the overall net PJM imports would have been net exports but for the net up-to congestion transaction imports.

- **Aggregate Imports and Exports in the Day-Ahead versus the Real-Time Energy Market.** In 2011, gross imports in the Day-Ahead Energy Market were 313

<sup>96</sup> The tables and figures within this section continue to show that the FE Interface and the MICHFE Interface Pricing Points existed in June 2011, to account for the single hour in June where FE was still an external interface.

<sup>97</sup> Net interchange is gross import volume less gross export volume. Thus, positive net interchange is equivalent to net imports and negative net interchange is equivalent to net exports.

percent of gross imports in the Real-Time Energy Market (210 percent for the calendar year 2010). In 2011, gross exports in the Day-Ahead Energy Market were 240 percent of gross exports in the Real-Time Energy Market (183 percent for the calendar year 2010). In 2011, net interchange was 6,576.2 GWh in the Day-Ahead Energy Market and -9,761.8 GWh in the Real-Time Energy Market compared to -6,470.0 GWh in the Day-Ahead Energy Market and -9,661.0 GWh in the Real-Time Energy Market for the calendar year 2010.

- Interface Imports and Exports in the Real-Time Energy Market.** In the Real-Time Energy Market, for the calendar year 2011, there were net exports at 14 of PJM's 21 interfaces. The top four net exporting interfaces in the Real-Time Energy Market accounted for 67.7 percent of the total net exports: PJM/New York Independent System Operator, Inc. (NYIS) with 22.0 percent, PJM/MidAmerican Energy Company (MEC) with 19.5 percent, PJM/Neptune (NEPT) with 14.0 percent and PJM/Cinergy Corporation (CIN) with 12.2 percent of the net export volume. The three separate interfaces that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT and PJM/Linden (LIND)) together represented 39.4 percent of the total net PJM exports in the Real-Time Energy Market. Six PJM interfaces had net imports, with two importing interfaces accounting for 74.0 percent of the total net imports: PJM/Ohio Valley Electric Corporation (OVEC) with 55.6 percent and PJM/LG&E Energy, L.L.C. (LGEE) with 18.4 percent.<sup>98</sup>
- Interface Pricing Point Imports and Exports in the Real-Time Energy Market.** In the Real-Time Energy Market, for the calendar year 2011, there were net exports at nine of PJM's 17 interface pricing points eligible for real-time transactions.<sup>99</sup> The top three net exporting interface pricing points in the Real-Time Energy Market accounted for 84.7 percent of the total net exports: PJM/MISO with 57.5 percent, PJM/NYIS with 16.6 percent and PJM/NEPTUNE (NEPT) with 10.6 percent of the net export volume. The three separate interface pricing points that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT and PJM/Linden (LIND)) together represented 29.8

percent of the total net PJM exports in the Real-Time Energy Market. Six PJM interface pricing points had net imports, with two importing interface pricing points accounting for 78.7 percent of the total net imports: PJM/SouthIMP with 40.7 percent and PJM/Ohio Valley Electric Corporation (OVEC) with 38.0 percent of the net import volume.<sup>100</sup>

- Interface Imports and Exports in the Day-Ahead Energy Market.** In the Day-Ahead Energy Market, for the calendar year 2011, there were net exports at 13 of PJM's 21 interfaces. The top three net exporting interfaces accounted for 60.5 percent of the total net exports: PJM/MidAmerican Energy Company (MEC) with 25.7 percent, PJM/Neptune (NEPT) with 20.4 percent and PJM/Linden (LIND) with 14.4 percent of the net export volume. The three separate interfaces that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT and PJM/LIND) together represented 32.5 percent of the total net PJM exports in the Day-Ahead Energy Market. Eight PJM interfaces had net imports in the Day-Ahead Energy Market, with three interfaces accounting for 95.5 percent of the total net imports: PJM/OVEC with 43.0 percent, PJM/Michigan Electric Coordinated System (MECS) with 31.2 percent and PJM/Eastern Alliant Energy Corporation (ALTE) with 21.3 percent.
- Interface Pricing Point Imports and Exports in the Day-Ahead Energy Market.** In the Day-Ahead Energy Market, for the calendar year 2011, there were net exports at eight of PJM's 19 interface pricing points eligible for day-ahead transactions. The top three net exporting interface pricing points in the Day-Ahead Energy Market accounted for 80.3 percent of the total net exports: PJM/SouthEXP with 39.7 percent, PJM/NEPTUNE (NEPT) with 26.7 percent, and PJM/Southeast with 13.9 percent of the net export volume. The three separate interface pricing points that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT and PJM/Linden (LIND)) together represented 13.9 percent of the total net PJM exports in the Real-Time Energy Market (PJM/NEPTUNE with 26.7 percent and PJM/LINDEN with 4.7 percent. The PJM/NYIS interface pricing point had net imports in the Day-Ahead Energy Market). Eleven PJM interface pricing points had net imports, with

<sup>98</sup> In the Real-Time Market, one PJM interface had a net interchange of zero (PJM/City Water Light & Power (CWLP)).

<sup>99</sup> There are two interface pricing points eligible for day-ahead transaction scheduling only (NIPSCO and Southeast).

<sup>100</sup> In the Real-Time Market, two PJM interface pricing points had a net interchange of zero (MICHFE and NCMPAEXP).

three importing interface pricing points accounting for 68.7 percent of the total net imports: PJM/Ohio Valley Electric Corporation (OVEC) with 36.9 percent, PJM/SouthIMP with 17.8 percent and PJM/NYIS with 14.0 percent of the net import volume.

## Interactions with Bordering Areas

### PJM Interface Pricing with Organized Markets

- PJM and MISO Interface Prices.** In 2011, the average price difference between the PJM/MISO Interface and the MISO/PJM Interface was consistent with the direction of the average flow. In 2011, the PJM average hourly Locational Marginal Price (LMP) at the PJM/MISO border was \$32.32 while the MISO LMP at the border was \$34.01, a difference of \$1.69. The average hourly flow during the calendar year 2011 was -1,570 MW. (The negative sign means that the flow was an export from PJM to MISO, which is consistent with the fact that the average MISO price was higher than the average PJM price.) However, the direction of flows was consistent with price differentials in only 45 percent of hours in 2011.
- PJM and New York ISO Interface Prices.** In 2011, the relationship between prices at the PJM/NYIS Interface and at the NYISO/PJM proxy bus and the relationship between interface price differentials and power flows continued to be affected by differences in institutional and operating practices between PJM and the NYISO. In 2011, the average price difference between PJM/NYIS Interface and at the NYISO/PJM proxy bus was inconsistent with the direction of the average flow. In 2011, the PJM average hourly LMP at the PJM/NYISO border was \$43.88 while the NYISO LMP at the border was \$42.33, a difference of \$1.55. The average hourly flow during the calendar year 2011 was -626 MW. (The negative sign means that the flow was an export from PJM to NYISO, which is inconsistent with the fact that the average PJM price was higher than the average NYISO price.) However, the direction of flows was consistent with price differentials in only 52 percent of the hours in 2011.
- Neptune Underwater Transmission Line to Long Island, New York.** The Neptune line is a 65-mile direct current (DC) merchant 230 kV transmission line, with a capacity of 660 MW, providing a direct connection between PJM (Sayreville, New Jersey), and NYISO (Nassau County on Long Island). The line is bidirectional, but Schedule 14 of the PJM Open Access Transmission Tariff provides that power flows will only be from PJM to New York. In 2011, the average difference between the PJM/Neptune price and the NYISO/Neptune price was consistent with the direction of the average flow. In 2011, the PJM average hourly LMP at the Neptune Interface was \$48.20 while the NYISO LMP at the Neptune Bus was \$54.11, a difference of \$5.91. The average hourly flow during the calendar year 2011 was -493 MW. (The negative sign means that the flow was an export from PJM to NYISO.) However, the direction of flows was consistent with price differentials in only 64 percent of the hours in 2011.
- Linden Variable Frequency Transformer (VFT) Facility.** The Linden VFT facility is a merchant transmission facility, with a capacity of 300 MW, providing a direct connection between PJM and NYISO. While the Linden VFT is a bidirectional facility, Schedule 16 of the PJM Open Access Transmission Tariff provided that power flows would only be from PJM to New York. On March 31, 2011, PJM, on behalf of Linden VFT, LLC, submitted a revision to Schedule 16 of the PJM Open Access Transmission Tariff which requested the addition of Schedule 16-A to the Tariff to provide the terms and conditions for transmission service on the Linden VFT Facility for imports into PJM.<sup>101</sup> On June 1, 2011, the Tariff revision became effective, allowing for the bidirectional flow across the Linden VFT facility. In 2011, the average price difference between the PJM/Linden price and the NYISO/Linden price was consistent with the direction of the average flow. In 2011, the PJM average hourly LMP at the Linden Interface was \$47.19 while the NYISO LMP at the Linden Bus was \$48.70, a difference of \$1.51. The average hourly flow during the calendar year 2011 was -122 MW. (The negative sign means that the flow was an export from PJM to NYISO.) However,

<sup>101</sup> See *PJM Interconnection, LLC*, Docket No. ER11-3250-000 (March 31, 2011).

the direction of flows was consistent with price differentials in only 61 percent of the hours in 2011.

- **Hudson DC Line.** The Hudson direct current (DC) line will be a bidirectional merchant 230 kV transmission line, with a capacity of 673 MW, providing a direct connection between PJM (Public Service Electric and Gas Company's (PSE&G) Bergen 230 kV Switching Station located in Ridgefield, New Jersey) and NYISO (Consolidated Edison's (ConEd) W. 49th Street 345 kV Substation in New York City). The connection will be a submarine AC cable system. While the Hudson DC line will be a bidirectional line, power flows will only be from PJM to New York because the Hudson Transmission Partners, LLC have only requested withdrawal rights (320 MW of firm withdrawal rights, and 353 MW of non-firm withdrawal rights). The Hudson DC line is expected to be in service late in 2012.

### Operating Agreements with Bordering Areas

- **PJM and MISO Joint Operating Agreement.**<sup>102</sup> The Joint Operating Agreement between MISO and PJM Interconnection, L.L.C., executed on December 31, 2003, continued during 2011. The PJM/MISO JOA includes provisions for market based congestion management that, for designated flowgates within MISO and PJM, allow for redispatch of units within the PJM and MISO regions to jointly manage congestion on these flowgates and to assign the costs of congestion management appropriately.
- **PJM and New York Independent System Operator, Inc. Joint Operating Agreement.**<sup>103</sup> On May 22, 2007, the PJM/NYISO JOA became effective. This agreement was developed to improve reliability. It also formalized the process of electronic checkout of schedules, the exchange of interchange schedules to facilitate calculations for available transfer capability (ATC) and standards for interchange revenue metering.

The PJM/NYISO JOA did not include provisions for market based congestion management or other market to market activity, so, in 2008, at the request

of PJM, PJM and NYISO began discussion of a market based congestion management protocol. On December 30, 2011, PJM and the NYISO filed JOA revisions with FERC that include a market to market process.<sup>104</sup>

- **PJM, MISO and TVA Joint Reliability Coordination Agreement.**<sup>105</sup> The Joint Reliability Coordination Agreement (JRCA) executed on April 22, 2005, provides for comprehensive reliability management among the wholesale electricity markets of MISO and PJM and the service territory of TVA. The parties meet on a yearly basis, and, in 2011, there were no developments. The agreement continued to be in effect in 2011.
- **PJM and Progress Energy Carolinas, Inc. Joint Operating Agreement.**<sup>106</sup> On September 9, 2005, the FERC approved a JOA between PJM and Progress Energy Carolinas, Inc. (PEC), with an effective date of July 30, 2005. As part of this agreement, both parties agreed to develop a formal Congestion Management Protocol (CMP). The parties meet on a yearly basis, and, in 2011, there were no developments. However, on May 25, 2011, PJM and Progress submitted a joint filing, requesting an additional six months to develop a mutually agreeable methodology to account for the compensation non-firm power flows have on each others transmission system.<sup>107</sup> The agreement remained in effect in 2011.
- **PJM and Virginia and Carolinas Area (VACAR) South Reliability Coordination Agreement.**<sup>108</sup> On May 23, 2007, PJM and VACAR South (VACAR is a sub-region within the NERC SERC Reliability Corporation (SERC) Region) entered into a reliability coordination agreement. It provides for system and outage coordination, emergency procedures and the exchange of data. Provisions are also made for regional studies and recommendations to improve the reliability of interconnected bulk power systems. The parties meet on a yearly basis, and, in

<sup>102</sup> See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C." (December 11, 2008) <<http://www.pjm.com/documents/agreements/~media/documents/agreements/joa-complete.ashx>>. (Accessed March 1, 2012)

<sup>103</sup> See "New York Independent System Operator, Inc., Joint Operating Agreement with PJM Interconnection, L.L.C." (September 14, 2007) <[http://www.nyiso.com/public/webdocs/documents/regulatory/agreements/interconnection\\_agreements/nyiso\\_pjm\\_joa\\_final.pdf](http://www.nyiso.com/public/webdocs/documents/regulatory/agreements/interconnection_agreements/nyiso_pjm_joa_final.pdf)>. (Accessed March 1, 2012)

<sup>104</sup> See "Jointly Submitted Market-to Market Coordination Compliance Filing," Docket No. ER12-718-000- (December 30, 2011).

<sup>105</sup> See "Congestion Management Process (CMP) Master," (May 1, 2008) <<http://www.pjm.com/documents/agreements/~media/documents/agreements/20080502-miso-pjm-tva-baseline-cmp.ashx>>. (Accessed March 1, 2012)

<sup>106</sup> See "Joint Operating Agreement (JOA) between Progress Energy Carolinas, Inc. and PJM" (September 17, 2010) <<http://www.pjm.com/documents/agreements/~media/documents/agreements/progress-pjm-joint-operating-agreement.ashx>>. (Accessed March 1, 2012)

<sup>107</sup> *PJM Interconnection, L.L.C. and Progress Energy Carolinas, Inc.*, Docket No. ER11-3637-000 (May 25, 2011)

<sup>108</sup> See "Adjacent Reliability Coordinator Coordination Agreement," (May 23, 2007) <<http://www.pjm.com/documents/agreements/~media/documents/agreements/executed-pjm-vacar-rc-agreement.ashx>>. (Accessed March 1, 2012)



2011, there were no developments. The agreement remained in effect in 2011.

### Other Agreements/Protocols with Bordering Areas

- **Consolidated Edison Company of New York, Inc. (Con Edison) and Public Service Electric and Gas Company (PSE&G) Wheeling Contracts.** In 2011, PJM continued to operate under the terms of the operating protocol developed in 2005 that applies uniquely to Con Edison.<sup>109</sup> This protocol allows Con Edison to elect up to the flow specified in each of two contracts through the PJM Day-Ahead Energy Market. A 600 MW contract is for firm service and a 400 MW contract has a priority higher than non-firm service, but lower than firm service. These elections obligate PSE&G to pay congestion costs associated with the daily elected level of service under the 600 MW contract and obligate Con Edison to pay congestion costs associated with the daily elected level of service under the 400 MW contract.

### Interchange Transaction Issues

- **Loop Flows.** Actual flows are the metered flows at an interface for a defined period. Scheduled flows are the flows scheduled at an interface for a defined period. Inadvertent interchange is the difference between the total actual flows for the PJM system (net actual interchange) and the total scheduled flows for the PJM system (net scheduled interchange) for a defined period. Loop flows are defined as the difference between actual and scheduled power flows at one or more specific interfaces.

Loop flow can arise from transactions scheduled into, out of, through or around the PJM system on contract paths that do not correspond to the actual physical paths on which energy flows. Loop flows exist because electricity flows on the path of least resistance regardless of the path specified by contractual agreement or regulatory prescription. In 2011, net scheduled interchange was -7,072 GWh and net actual interchange was -7,576 GWh, a difference of 504 GWh or 7.1 percent, an increase from 5.2 percent for the calendar year 2010. While actual interchange exceeded scheduled interchange in 2011, the opposite was true in 2010.

This difference is system inadvertent. The total inadvertent over the two year period including 2010 and 2011 was 1.1 percent. PJM attempts to minimize the amount of accumulated inadvertent interchange by continually monitoring and correcting for inadvertent interchange.

- **PJM Transmission Loading Relief Procedures (TLRs).** In 2011, PJM issued 62 TLRs of level 3a or higher. Of the 62 TLRs issued, 34 events were TLR level 3a, and the remaining 28 events were TLR level 3b. TLRs are used to control congestion on the transmission system when it cannot be controlled via market forces. The fact that PJM issued only 62 TLRs in 2011, compared to 110 during the calendar year 2010, reflects the ability to successfully control congestion through redispatch of generation including redispatch under the JOA with MISO. PJM's operating rules allow PJM to reconfigure the transmission system prior to reaching system operating limits that would otherwise require the need for higher level TLRs.
- **Up-To Congestion.** Following the elimination of the requirement to procure transmission for up-to congestion transactions in 2010, the volume of transactions significantly increased. The average number of up-to congestion bids that had approved MWh in the Day-Ahead Market increased to 13,396 bids per day, with an average cleared volume of 530,476 MWh per day, in 2011, compared to an average of 4,269 bids per day, with an average cleared volume of 310,660 MWh per day, for the calendar year 2010.

The MMU is concerned about the impacts of the significant increase in up-to congestion transaction volume on the Day-Ahead Energy Market. Up-to congestion transactions impact the day-ahead dispatch. Up-to congestion transactions do not pay operating reserves charges and there is a question as to whether current credit policies adequately address up to congestion transactions.

- **Willing to Pay Congestion and Not Willing to Pay Congestion.** Total uncollected congestion charges in 2011 were -\$20,955, compared to \$3.3 million for the calendar year 2010. Uncollected congestion charges are accrued when not willing to pay

<sup>109</sup> See 111 FERC ¶ 61,228 (2005).

congestion transactions are not curtailed when congestion between the specified source and sink is present. Uncollected congestion charges also apply when there is negative congestion (when the LMP at the source is greater than the LMP at the sink) which was the case in for the net uncollected congestion charges in 2011. The fact that there was a total negative congestion collection in 2011, for not willing to pay congestion transactions, means that market participants who utilized the not willing to pay congestion transmission option for their transactions had transactions that flowed in the direction opposite to congestion.

- Elimination of Sources and Sinks.** The MMU recommended that PJM eliminate the internal source and sink bus designations from external energy transaction scheduling in the PJM Day-Ahead and Real-Time Energy Markets. Designating a specific internal bus at which a market participant buys or sells energy creates a mismatch between the day-ahead and real-time energy flows, as it is impossible to control where the power will actually flow based on the physics of the system, and can affect the day-ahead clearing price, which can affect other participant positions. Market inefficiencies are created when the day-ahead dispatch does not match the real-time dispatch. On April 12, 2011, the PJM Market Implementation Committee (MIC) endorsed the elimination of internal source and sink designations in both the Day-Ahead and Real-Time Energy Markets.<sup>110</sup> These modifications are currently being evaluated by PJM. It is expected that implementation of these changes will occur by the end of the second quarter 2012.
- Spot Import.** In 2009, the MMU and PJM jointly addressed a concern regarding the underutilization of spot import service. Because spot import service is available at no cost, and is limited by available transfer capabilities (ATC), market participants were able to reserve all of the available service with no economic risk. The market participants could then choose not to submit a transaction utilizing the service if they did not believe the transaction would be economic. By reserving the spot import service and not scheduling against it, they effectively

withheld the service from other market participants who wished to utilize it.

In 2011, PJM suggested including a utilization factor in the ATC calculation for all non-firm service. This utilization factor is the ratio of utilized transmission on a particular path to the amount of that transmission reserved when determining how much transmission should be granted. Including the utilization factor will allow PJM to adjust the amount of ATC available to permit a more efficient use of the transmission system. This proposed methodology was approved by PJM stakeholders during the third quarter of 2011. It is expected that implementation of these changes will occur by the end of the third quarter 2012.

- Real-Time Dispatchable Transactions.** Real-Time Dispatchable Transactions, also known as “real-time with price” transactions, allow market participants to specify a floor or ceiling price which PJM dispatch will evaluate on an hourly basis prior to implementing the transaction.

Dispatchable transactions were initially a valuable tool for market participants. The transparency of real-time LMPs and the reduction of the required notification period from 60 minutes to 20 minutes have eliminated the value that dispatchable transactions once provided market participants. The value that dispatchable transactions once provided market participants no longer exist, but the risk to other market participants is substantial, as they are subject to providing the operating reserve credits. Dispatchable transactions now only serve as a potential mechanism for receiving those operating reserve credits.

Balancing operating reserve credits are paid to importing dispatchable transactions as a guarantee of the transaction price. Dispatchable transactions are made whole when the hourly integrated LMP does not meet the specified minimum price offer in the hours when the transaction was active. In 2011, these balancing operating reserve credits were \$1.3 million, a decrease from \$23.0 million for the calendar year 2010. The reasons for the reduction in these balancing operating reserve credits were active monitoring by the MMU and the absence of any such dispatchable transactions after April, 2011.

<sup>110</sup> See “Meeting Minutes” Minutes from PJM’s MIC meeting, <<http://www.pjm.com/~media/committees-groups/committees/mic/20110412/20110412-mic-minutes.ashx>>. (May 16, 2011)

The MMU recommended that dispatchable transactions either be eliminated as a product in the PJM Real-Time Energy Market, or to keep the product, eliminate the operating reserve credits allocated to importing dispatchable transactions and to incorporate the product into the Intermediate Term Security Constrained Economic Dispatch (ITSCED) tool. On May 10, 2011, the PJM Market Implementation Committee (MIC) endorsed the recommendation to incorporate the dispatchable transaction product into the ITSCED application.<sup>111</sup> PJM stated that the inclusion of this product would require minimal effort, and could be implemented by the end of 2011 or early in the first quarter of 2012.

- **Internal Bilateral Transactions.** In the third quarter of 2011, it was discovered that a number of companies had been utilizing internal bilateral transactions to inappropriately reduce, or eliminate, their exposure to balancing operating reserve (BOR) charges associated with their PJM Day-Ahead Market positions. This issue is currently being addressed at FERC and through the PJM stakeholder process.<sup>112</sup>

## Section 8 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 hedging tools (FTRs and Auction Revenue Rights (ARRs) in PJM) and transparent, least cost, security constrained economic dispatch for all available generation. Non market areas do not include these features. The market areas are extremely transparent and the non market areas are not transparent.

On June 1, 2011, at 0100, the American Transmission System, Inc. Control Zone was integrated into PJM. This integration eliminated the First Energy (FE)

Interface, which reduced the total number of external PJM interfaces from 21 to 20 interfaces. Additionally, following the ATSI integration, the MICHFE Interface Pricing Point was eliminated, reducing the total number of real-time interface pricing points from 17 to 16.

The MMU analyzed the transactions between PJM and its neighboring balancing authorities during 2011, including evolving transaction patterns, economics and issues. In 2011, PJM was a net exporter of energy in the Real-Time Market and a net importer of energy in the Day-Ahead Market. The primary reason that PJM became a net importer of energy in the Day-Ahead Market in 2011 was the significant increase in up-to congestion transactions and the fact that up-to congestion transactions were net imports for most of that period.

A large share of both import and export activity occurred at a small number of interfaces. Four interfaces accounted for 67.7 percent of the total real-time net exports and two interfaces accounted for 74.0 percent of the real-time net import volume. Three interfaces accounted for 60.5 percent of the total day-ahead net exports and three interfaces accounted for 95.5 percent of the day-ahead net import volume.

A large share of both import and export activity also occurred at a small number of interface pricing points. Three interface pricing points accounted for 84.7 percent of the total real-time net exports and two interfaces accounted for 78.7 percent of the real-time net import volume. Three interface pricing points accounted for 80.3 percent of the total day-ahead net exports and three interface pricing points accounted for 68.7 percent of the day-ahead net import volume.

In 2011, the direction of power flows at the borders between PJM and MISO and between PJM and NYISO was not consistent with real-time energy market price differences for many hours, 55 percent between PJM and MISO and 48 percent between PJM and NYISO. The MMU recommends that PJM work with both MISO and NYISO to improve the ways in which interface flows and prices are established in order to help ensure that interface prices are closer to the efficient levels that would result if the interface between balancing authorities were entirely internal to an LMP market. In an LMP market, redispatch based on LMP and generator

<sup>111</sup> See "Meeting Minutes" Minutes from PJM's MIC meeting, <<http://www.pjm.com/~media/committees-groups/committees/mic/20110510/20110510-mic-minutes.ashx>>. (July 13, 2011)

<sup>112</sup> *DC Energy, LLC and DC Energy Mid-Atlantic, LLC v. PJM Interconnection, LLC*, Docket No. EL12-8-000 (October 28, 2011).

offers would result in an efficient dispatch and efficient prices. Price differences at the seams continue to be determined by reliance on market participants to see the prices and react to the prices by scheduling transactions with both an internal lag and an RTO administrative lag.

Interactions between PJM and other balancing authorities should be governed by the same market principles that govern transactions within PJM. That is not yet the case. The MMU recommends that PJM ensure that all the arrangements between PJM and other balancing authorities be reviewed and modified as necessary to ensure consistency with basic market principles and that PJM not enter into any additional arrangements that are not consistent with basic market principles.

## Section 9, Ancillary Services

### Highlights

- The weighted average Regulation Market clearing price, including opportunity cost, for 2011 was \$16.21 per MW.<sup>113</sup> This was a decrease of \$1.87, or 10 percent, from the average price for regulation in 2010. The total cost of regulation decreased by \$2.79 from \$32.07 per MW in 2010, to \$29.28, or 8.7 percent. In 2011 the weighted Regulation Market clearing price was only 55 percent of the total regulation cost per MW, compared to 56 percent of the total costs of regulation per MW in 2010. (See Volume II, page 236)
- The weighted average clearing price for Tier 2 Synchronized Reserve Market in the Mid-Atlantic Subzone was \$11.81 per MW in 2011, a \$1.26 per MW increase from 2010.<sup>114</sup> The total cost of synchronized reserves per MWh in 2011 was \$15.48, a 7.4 percent increase from the total cost of synchronized reserves (\$14.41) during 2010. The weighted average Synchronized Reserve Market clearing price was 76 percent of the weighted average total cost per MW of synchronized reserve in 2011, up from 73 percent in 2010. (See Volume II, page 251)
- The weighted DASR market clearing price in 2011 was \$0.55 per MW. In 2010, the weighted price of DASR was \$0.16 per MW. The year over year increase in the weighted average price per MW of DASR was attributable to several days of high DASR prices in June, July and August. (See Volume II, page 256)
- Black start zonal charges 2011 ranged from \$0.04 per MW in the DLCO zone to \$0.90 per MW in the BGE zone (See Volume II, page 257)

### Recommendations

- The Regulation Market design and implementation continue to be flawed and require a detailed review to ensure that the market will produce competitive outcomes. The MMU recommends a number of market design changes to improve the performance of the Regulation Market, including use of a single clearing price based on actual LMP, modifications to

<sup>113</sup> The term "weighted" when applied to clearing prices in the Regulation Market means clearing prices weighted by the MW of cleared regulation.

<sup>114</sup> The term "weighted" when applied to clearing prices in the Synchronized Reserve Market means clearing prices weighted by the MW of cleared synchronized reserve.

the LOC calculation methodology, a software change to save some data elements necessary for verifying market outcomes, and further documentation of the implementation of the market design through SPREGO. The MMU is hopeful that the opportunity cost issue can be resolved in 2012.

- PJM will propose a redesign of the Regulation Market in 2011 to address fast response resources and other design issues.
- The MMU recommends that the single clearing price for synchronized reserves be determined based on the actual LMP. This is consistent with PJM's recommendation on this topic in the scarcity pricing matter. The MMU also recommends that documentation of the Tier 1 synchronize reserve deselection process be published.
- The MMU recommends that the DASR Market rules be modified to incorporate the application of the three pivotal supplier test and cost-based offer caps in order to address potential market power issues.
- The MMU recommends that PJM, FERC, reliability authorities and state regulators reevaluate the way in which black start service is procured in order to ensure that procurement is done in a least cost manner for the entire PJM market. PJM should have responsibility to prepare the black start restoration plan for the region, with Members playing an advisory role. PJM should have the responsibility to procure required black start service on a least cost basis through a transparent process.
- The MMU recommends that the Synchronized Reserve Market design be modified to address the issue of units which offer and clear synchronized reserve but fail to provide synchronized reserve when an actual spinning event occurs.
- The MMU recommends that PJM document the reasons each time it changes the Tier 1 synchronized reserve transfer capability into the Mid-Atlantic subzone market because of the potential impacts on the market.

## Overview

### Regulation Market

The PJM Regulation Market in 2011 continued to be operated as a single market. There have been no structural changes since December 1, 2008, when PJM

implemented four changes to the Regulation Market: introducing the three pivotal supplier test for market power; increasing the margin for cost-based regulation offers; modifying the calculation of lost opportunity cost (LOC); and terminating the offset of regulation revenues against operating reserve credits.<sup>115</sup>

### Market Structure

- **Supply.** In 2011, the supply of offered and eligible regulation in PJM was both stable and adequate. The ratio of offered and eligible regulation to regulation required averaged 3.00 for 2011. This is a 1.7 percent increase over 2010 when the ratio was 2.95.

Although PJM rules allow up to 25 percent of the regulation requirement to be satisfied by demand resources, other rules (a minimum offer requirement of 1 MW as well as the prohibition of demand resources offering both economic and emergency demand reduction combined with a prohibition of a demand resource being represented by more than one CSP) made it impractical. On November 21, 2011, these rules were modified and the first two demand resources offered and cleared regulation.

- **Demand.** The on-peak regulation requirement is equal to 1.0 percent of the forecast peak load for the PJM RTO for the day and the off-peak requirement is equal to 1.0 percent of the forecast valley load for the PJM RTO for the day. The average hourly regulation demand in 2011 was 925 MW (842 MW off peak, and 1,017 MW on peak). This is a 32 MW increase in the average hourly regulation demand of 893 MW in 2010 (811 MW off peak, and 981 MW on peak).

Of the LSEs' obligation to provide regulation during 2011, 81.8 percent was purchased in the spot market (82.2 percent in 2010), 15.6 percent was self scheduled (15.5 percent in 2010), and 2.6 percent was purchased bilaterally (2.3 percent in 2010).

- **Market Concentration.** In 2011, the PJM Regulation Market had a weighted, average Herfindahl-Hirschman Index (HHI) of 1630 which is classified

<sup>115</sup> All existing PJM tariffs, and any changes to these tariffs, are approved by FERC. The MMU describes the full history of the changes to the tariff provisions governing the Regulation Market in the 2011 State of the Market Report for PJM, Volume II, Section 9, "Ancillary Service Markets."

as “moderately concentrated.”<sup>116</sup> The minimum hourly HHI was 818 and the maximum hourly HHI was 4005. The largest hourly market share in any single hour was 58.9 percent, and 84.3 percent of all hours had a maximum market share greater than 20 percent.<sup>117</sup> In 2011, 82.1 percent of hours had one or more pivotal suppliers which failed PJM’s three pivotal supplier test (73.3 percent of hours failed the three pivotal supplier test in 2010). The MMU concludes from these results that the PJM Regulation Market in 2011 was characterized by structural market power in 82.1 percent of the hours.

## Market Conduct

- **Offers.** Daily regulation offer prices are submitted for each unit by the unit owner. Owners are required to submit unit specific cost based offers and owners also have the option to submit price based offers. Cost based offers apply for the entire day and are subject to validation using unit specific parameters submitted with the offer. All price based offers also apply for the entire day and remain subject to the \$100 per MWh offer cap.<sup>118</sup> In computing the market solution, PJM calculates a unit specific opportunity cost based on forecast LMP, and adds it to each offer. The offers made by unit owners and the opportunity cost adder comprise the total offer to the Regulation Market for each unit. Using a supply curve based on these offers, PJM solves the Regulation Market and then tests that solution to see which, if any, suppliers of eligible regulation are pivotal. The offers of all units of owners who fail the three pivotal supplier test for an hour are capped at the lesser of their cost based or price based offer. The Regulation Market is then cleared again.

<sup>116</sup> See the 2011 *State of the Market Report for PJM, Volume II*, Section 2, “Energy Market,” at “Market Concentration” for a more complete discussion of concentration ratios and the Herfindahl-Hirschman Index (HHI). Consistent with common application, the market share and HHI calculations presented in the SOM are based on supply that is cleared in the market in every hour, not on measures of available capacity.

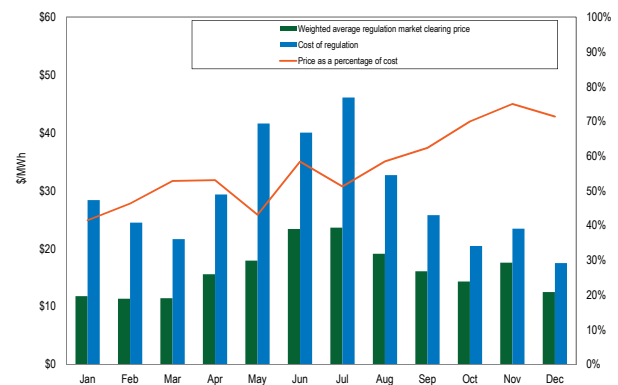
<sup>117</sup> HHI and market share are commonly used but potentially misleading metrics for structural market power. Traditional HHI and market share analyses tend to assume homogeneity in the costs of suppliers. It is often assumed, for example, that small suppliers have the highest costs and that the largest suppliers have the lowest costs. This assumption leads to the conclusion that small suppliers compete among themselves at the margin, and therefore participants with small market share do not have market power. This assumption and related conclusion are not generally correct in electricity markets, like the Regulation Market, where location and unit specific parameters are significant determinants of the costs to provide service, not the relative market share of the participant. The three pivotal supplier test provides a more accurate metric for structural market power because it measures, for the relevant time period, the relationship between demand in a given market and the relative importance of individual suppliers in meeting that demand. The MMU uses the results of the three pivotal supplier tests, not HHI or market share measures, as the basis for conclusions regarding structural market power.

<sup>118</sup> See PJM, “Manual 11, Energy and Ancillary Services Market Operations,” Revision 49 (January 1, 2012) p. 55.

## Market Performance

- **Price.** The weighted Regulation Market clearing price for the PJM Regulation Market in 2011 was \$16.21 per MW. This was a decrease of \$1.87, or 10 percent, from the weighted average price for regulation in 2010. The total cost of regulation decreased by \$2.79 from \$32.07 per MW in 2010, to \$29.28, or 8.7 percent. In 2011 the weighted Regulation Market clearing price was only 55 percent of the total regulation cost per MW, compared to 56 percent of the total costs of regulation per MW in 2010. The difference between the total cost of regulation and the clearing price of regulation was primarily the result of using forecasted LMP to calculate the opportunity costs which are incorporated in the offers used to clear the market. The actual costs of regulation include payments to each individual unit for its after the fact opportunity cost, which is based on actual LMP. In addition, units scheduled to regulate are, at times, switched with other units in an owner’s fleet of regulation units by the owner or at the direction of PJM Dispatch as a result of binding constraints or performance problems.

Figure 13 Monthly weighted, average regulation cost and price: Calendar year 2011



## Synchronized Reserve Market

PJM retained the two synchronized reserve markets it implemented on February 1, 2007. The RFC Synchronized Reserve Zone reliability requirements are set by the ReliabilityFirst Corporation. The Southern Synchronized Reserve Zone (Dominion) reliability requirements are set by the Southeastern Electric Reliability Council (SERC).

The integration of the Trans-Allegheny Line (TrAIL) project (performed in three stages April 8, May 13, and May 20, 2011) resulted in a change to the interface defining the Mid-Atlantic subzone of the RFC Synchronized Reserve Market.<sup>119</sup> That interface had been the AP South interface since March 2009. After the implementation of TrAIL, Bedington – Black Oak became the most limiting interface and remained so throughout 2011. PJM reserves the right to revise the interface defining the Mid-Atlantic Subzone in accordance with operational and reliability needs.<sup>120</sup> From May 20, 2011, through the end of September the percent of Tier 1 synchronized reserve available west of the interface that is also available in the Mid-Atlantic subzone (transfer capacity) was set to 30 percent. Since then, PJM has changed the transfer capacity several times varying from 50 percent to 15 percent at the end of 2011. The higher the assumed transfer capability, the greater the supply of Tier 1 that is available from west of the interface to meet synchronized reserve requirements in the Mid-Atlantic subzone. The more Tier 1 synchronized reserve available, the less Tier 2 synchronized reserve needs to be cleared. These changes to the transfer interface capacity did affect the Synchronized Reserve Market by changing the amount of Tier 2 required in the Mid-Atlantic Subzone. Synchronized reserves added out of market were 1.6 percent of all synchronized reserves in 2011, down from 3.4 percent in 2010.<sup>121</sup> After-market opportunity cost payments accounted for 16.8 percent of total costs in 2011 compared to 26.8 percent in 2010.

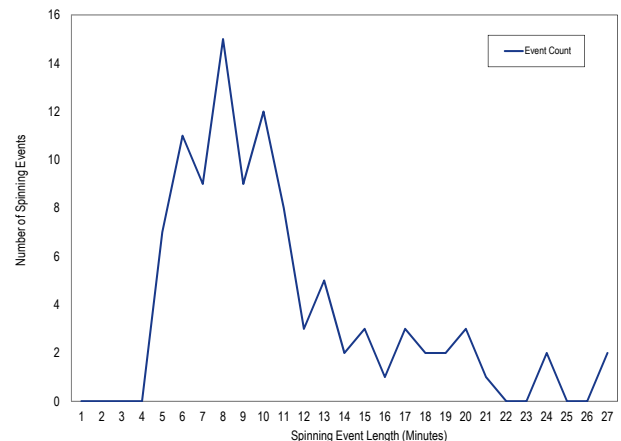
## Market Structure

- **Supply.** In 2011 the supply of offered and eligible synchronized reserve was both stable and adequate. The contribution of DSR to the Synchronized Reserve Market remains significant. Demand side resources are relatively low cost, and their participation in this market lowers overall Synchronized Reserve prices. The ratio of offered and eligible synchronized reserve MW to the administrative synchronized reserve required (1,300 MW) was 1.08 for the Mid-Atlantic Subzone.<sup>122</sup> This is a six percent decrease

from 2010 when the ratio was 1.16. Much of the required synchronized reserve is supplied from on-line (Tier 1) synchronized reserve resources. The ratio of eligible synchronized reserve MW to the required Tier 2 MW is much higher. The ratio of offered and eligible synchronized reserve to the required Tier 2 depends on how much Tier 2 synchronized reserve is needed but the median ratio for all cleared Tier 2 hours in 2011 was 2.89 for the Mid-Atlantic Subzone. The ratio of offered and eligible synchronized reserve to the required Tier 2 was 3.00 for the RFC Zone for all hours in which a Tier 2 market was cleared. This is an 11 percent increase from 2010 when the ratio was 2.68. For the RFC Zone the offered and eligible excess supply ratio is determined using the administratively required level of synchronized reserve. The requirement for Tier 2 synchronized reserve is lower than the required reserve level for synchronized reserve because there is usually a significant amount of Tier 1 synchronized reserve available.

- **Demand.** PJM made no changes to the default hourly required synchronized reserve requirements in 2011. The synchronized reserve requirement in the RFC zone was raised to 1,700 MW on February 9 and 10, 2011, for double spinning, and was raised to 1,760 MW on May 3, 4, 5 and 6 for double spinning. On September 7 the Synchronized Reserve requirement was raised to 1,700 MW for most of the day for double spinning.

**Figure 14 Spinning events duration distribution curve, January 2009 through December 2011**



<sup>119</sup> PJM.com "TrAIL Operational Impacts," <<http://www.pjm.com/~media/committees-groups/committees/oc/20111018/20111018-item-08-trail-operational-impacts.ashx>>. (October 2011).

<sup>120</sup> See PJM, "Manual 11, Energy and Ancillary Services Market Operations," Revision 49 (January 1, 2012), p. 67.

<sup>121</sup> This figure was incorrectly reported as "five percent" in 2010 State of the Market Report for PJM, Section 6, "Ancillary Service Markets", p.423.

<sup>122</sup> The Synchronized Reserve Market in the Southern Region cleared in so few hours that related data for that market is not meaningful.

In 2011, in the Mid-Atlantic Subzone, a Tier 2 synchronized reserve market was cleared in 83 percent of hours. This is a 24 percent increase from 2010, when the market cleared in 67 percent of hours. In 2011, the average required Tier 2 synchronized reserve (including self scheduled) was 527 MW. In 2010 the average required Tier 2 synchronized reserve was 358 MW.

Synchronized reserves added out of market were 1.6 percent of all Mid-Atlantic Subzone synchronized reserves in 2011. Synchronized reserves added out of market were 3.4 percent of all Mid-Atlantic Subzone synchronized reserves in 2010.

Market demand for Tier 2 is less than the requirement for synchronized reserve by the amount of forecast Tier 1 synchronized reserve available at the time a Synchronized Reserve Market is cleared. As a result of the level of Tier 1 reserves in the RFC Synchronized Reserve Zone, less than one percent (16 hours) cleared a Tier 2 Synchronized Reserve Market in the RFC in 2011. A Tier 2 Synchronized Reserve Market was cleared for the Southern Synchronized Reserve Zone in 26 hours in 2011.

- **Market Concentration.** The average weighted cleared Synchronized Reserve Market HHI for the Mid-Atlantic Subzone in 2011 was 2637, which is classified as “highly concentrated.”<sup>123</sup> For purchased synchronized reserve (cleared plus added) the HHI was 2675. In 2011, 46 percent of hours had a maximum market share greater than 40 percent, compared to 68 percent of hours in the same period of 2010.

In the Mid-Atlantic Subzone, in 2011, 63 percent of hours that cleared a synchronized reserve market had three or fewer pivotal suppliers. In 2010, 62 percent of hours had three or fewer pivotal suppliers. The MMU concludes from these TPS results that the Mid-Atlantic Subzone Synchronized Reserve Market in 2011 was characterized by structural market power.

## Market Conduct

- **Offers.** Daily cost based offer prices are submitted for each unit by the unit owner, and PJM adds

opportunity cost calculated using LMP forecasts, which together comprise the total offer for each unit to the Synchronized Reserve Market. The synchronized reserve offer made by the unit owner is subject to an offer cap of marginal cost plus \$7.50 per MW, plus lost opportunity cost. All suppliers are paid the higher of the market clearing price or their offer plus their unit specific opportunity cost.

Total MW of cleared demand side resources increased in 2011 over 2010 (from 613,762 MW to 982,434 MW). The DSR share of the total Synchronized Reserve Market increased from 16.5 percent in 2010 to 17.7 percent in 2011. Demand side resources satisfied 100 percent of the Tier 2 Synchronized Reserve market in 6.6 percent of hours in 2011 compared to 8.0 percent of hours in 2010.

- **Compliance.** The MMU has reviewed synchronized reserve non-compliance between 2009 and 2011 and concluded that the incentive/penalty structure is not adequate. Although providers of Tier 2 synchronized reserve are paid for making synchronized reserve MW available every hour, it is only during spinning events that such Tier 2 synchronized reserve is actually used. The result is that it is possible to provide the service profitably with a very low level of compliance. This behavior does exist in this market. PJM’s synchronized reserve penalty structure fails to penalize this behavior adequately. The MMU recommends that the Synchronized Reserve Market non-compliance penalties be restructured to address this issue and provide stronger incentives for compliance.

## Market Performance

- **Price.** The weighted average price for Tier 2 synchronized reserve in the Mid-Atlantic Subzone was \$11.81 per MW in 2011, a \$1.26 per MW increase from 2010. The total cost of synchronized reserves per MWh in 2011 was \$15.48, a \$1.07 increase (7.4 percent) from the \$14.41 cost of synchronized reserve in 2010. The market clearing price was 76 percent of the total synchronized reserve cost per MW in 2011, up from 73 percent in 2010.

<sup>123</sup> See the 2011 *State of the Market Report for PJM, Volume II, Section 2, “Energy Market”* at “Market Concentration” for a more complete discussion of concentration ratios and the Herfindahl-Hirschman Index (HHI).



The difference between the total cost of synchronized reserve and the clearing price of synchronized reserve can be attributed to two factors. Using forecasted LMP to calculate the opportunity costs which are incorporated in the offers used to clear the market. The actual costs of synchronized reserve include payments to each individual unit for its after the fact opportunity cost, which is based on actual LMP.

PJM changed the estimates of Tier 1 reserves over a wide range in 2011, without providing an explanation of the determinants of Tier 1 reserves. These estimates have a significant impact on the market.

- **Adequacy.** A synchronized reserve deficit occurs when the combination of Tier 1 and Tier 2 synchronized reserve is not adequate to meet the synchronized reserve requirement. Neither PJM Synchronized Reserve Market experienced a deficit in 2011.

## DASR

On June 1, 2008 PJM introduced the Day-Ahead Scheduling Reserve Market (DASR), as required by the RPM settlement.<sup>124</sup> The purpose of this market is to satisfy supplemental (30-minute) reserve requirements with a market-based mechanism that allows generation resources to offer their reserve energy at a price and compensates cleared supply at a single market clearing price. The DASR 30-minute reserve requirements are determined for each reliability region.<sup>125</sup> The RFC and Dominion DASR requirements are added together to form a single RTO DASR requirement which is obtained via the DASR Market. The requirement is applicable for all hours of the operating day. If the DASR Market does not result in procuring adequate scheduling reserves, PJM is required to schedule additional operating reserves.

## Market Structure

- **Concentration.** In 2011, there were 21 hours in the DASR market which failed the three pivotal supplier test. All 21 hours occurred in June, July and August during periods of high demand. The current structure of PJM's DASR Market does not include the three pivotal supplier test. The MMU

recommends that the three pivotal supplier test be incorporated in the DASR market.

- **Demand.** In 2011, the required DASR was 7.11 percent of peak load forecast, up from 6.88 percent in 2010.<sup>126</sup> The DASR requirement is a sum of the load forecast error and the forced outage rate. From 2010 the load forecast error declined from 1.90 percent to 1.87 percent. The forced outage rate increased from 4.98 percent to 5.23 percent. Added together the 2011 DASR requirement was 7.11 percent. The DASR MW purchased averaged 6,500 MW per hour for 2011, an increase from 6,033 MW per hour in 2010.

## Market Conduct

- **Withholding.** Economic withholding remains an issue in the DASR Market, but the nature of economic withholding in the DASR Market changed in June. The marginal cost of providing DASR is zero. In the first five months of 2011, five percent of units offered at \$50 or more and four percent offered at more than \$900. Most of these offers were reduced during the month of June but remained at levels exceeding competitive levels. Between June 1, and December 31, 2011, thirteen percent of all units offered DASR at levels above \$5, while less than one percent of units offered above \$50. Two units offered above \$900. PJM rules require all units with reserve capability that can be converted into energy within 30 minutes to offer into the DASR Market.<sup>127</sup> Units that do not offer have their offers set to zero.
- **DSR.** Demand side resources do participate in the DASR Market, but no demand resource cleared the DASR Market in 2011.

## Market Performance

- **Price.** The weighted DASR market clearing price 2011 was \$0.55 per MW. In 2010, the weighted price of DASR was \$0.16 per MW. The increase in the weighted average price per MW of DASR can be attributed to several days of extremely high DASR prices in June, July and August (a maximum price of \$217.12 occurred on July 21, 2011). These high prices were primarily the result of high demand

<sup>124</sup> See 117 FERC ¶ 61,331 (2006).

<sup>125</sup> See PJM. "Manual 13: Emergency Operations," Revision 47, (January 1, 2011); pp 11-12.

<sup>126</sup> See the 2011 *State of the Market Report for PJM*, Volume II, Section 9, "Ancillary Services" at Day Ahead Scheduling Reserve (DASR).

<sup>127</sup> PJM. "Manual 11, Energy and Ancillary Services Market Operations," Revision 49 (January 1, 2012), pp. 123-124.

and limited supply which created the need for redispatch in the Day-Ahead Energy Market in order to provide DADR. The result was that DADR prices in these hours reflected opportunity costs associated with the redispatch. DADR prices are calculated as the sum of the offer price plus the opportunity cost. For most hours the price is comprised entirely of offer price. In 56 percent of hours in 2011 the DADR Market Clearing Price was \$0.00. Most, 97 percent, DADR clearing prices consist solely of the offer price. For a few of the high price hours the price is composed almost entirely of LOC. For the top 0.5 percent (average clearing price = \$86.25) of hours 99.7 percent of the price is determined by opportunity cost. For the bottom 99.5 percent (average clearing price = \$0.12) of hours less than two percent of the price is composed of LOC.

## Black Start Service

Black start service is necessary to help ensure 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 with a high operating factor to automatically remain operating at reduced levels when disconnected from the grid.<sup>128</sup>

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

The MMU has concerns that there is a disconnect between a service that is required for system reliability, the balkanized approach to procuring that service, and the need to secure voluntary participation in the system restoration plans from the relatively few potential providers at the critical locations identified. The current process provides for PJM and transmission owners to jointly develop and administer the black start service plan for each transmission zone. These rules should be revised to assign responsibility for administering the

plan to PJM and allow transmission owners to play an advisory role.

PJM does not have a market to provide black start service, but compensates black start resource owners on the basis of an incentive rate or for all costs associated with providing this service, as defined in the tariff. In 2011, charges were \$13.63 million. This is 37 percent higher than 2010, when total black start service charges were \$9.98 million. There was substantial zonal variation. The increased cost of black start in 2011 is attributable to updated Schedule 6A (to the OATT) rates for all units, major refurbishments of black start resources in the BGE zone, and operating reserve charges associated with black start resources in the AEP zone. The increased Schedule 6A rates included net cost of new entry, VOM, bond rates, and oil forward strip.

Black start zonal charges in 2011 (including operating reserves for black start units) ranged from \$0.04 per MW in the DLCO zone to \$0.90 per MW in the BGE zone. Black start costs in the BGE zone increased due to major refurbishments of multiple black start resources. The black start resources were identified as critical assets in BGE's black start restoration plan by PJM and the transmission owner. The resources undergoing major refurbishment through the black start process are recovering capital investment costs to maintain the units as black start resources using the capital recovery factor (CRF) from Schedule 6A rather than the standard incentive rate provided in the tariff for black start resources. During the recovery period the unit's annual Black Start capital cost recovery will be limited to the greater of the black start payments or capacity market revenues but the commitment to provide black start services from the units does not match the obligation of customers to pay 100 percent of the capital costs of the refurbishment over an accelerated period.<sup>129</sup>

## Ancillary Services costs per MW of load: 2001 - 2011

Table 14 shows PJM ancillary services costs for 2001 through 2011 on a per MW of load basis. The Scheduling, System Control, and Dispatch category of costs is comprised of PJM Scheduling, PJM System

128 OATT Schedule 1 § 1.3BB.

129 PJM.com "Automated Formula Rate Adjustment Process," Revision 0 <<http://www.pjm.com/~media/committees-groups/task-forces/bsstf/20100420/20100420-automated-formula-rate-adjustment-process.ashx>>. (March 24, 2010).

Control and PJM Dispatch; Owner Scheduling, Owner System Control and Owner Dispatch; Other Supporting Facilities; Black Start Services; Direct Assignment Facilities; and ReliabilityFirst Corporation charges. Supplementary Operating Reserve includes Day-Ahead Operating Reserve; Balancing Operating Reserve; and Synchronous Condensing.

**Table 14 History of ancillary services costs per MW of Load: 2001 through 2011**

Year	Regulation	Scheduling, Dispatch, and System Control	Reactive	Synchronized Reserve	Supplementary Operating Reserve
2001	\$0.50	\$0.44	\$0.22	\$0.00	\$1.07
2002	\$0.45	\$0.53	\$0.21	\$0.07	\$0.63
2003	\$0.50	\$0.61	\$0.24	\$0.14	\$0.83
2004	\$0.50	\$0.60	\$0.25	\$0.13	\$0.90
2005	\$0.79	\$0.47	\$0.26	\$0.11	\$0.93
2006	\$0.53	\$0.48	\$0.29	\$0.08	\$0.43
2007	\$0.63	\$0.47	\$0.29	\$0.06	\$0.58
2008	\$0.68	\$0.40	\$0.31	\$0.08	\$0.59
2009	\$0.34	\$0.32	\$0.37	\$0.05	\$0.48
2010	\$0.34	\$0.38	\$0.41	\$0.07	\$0.73
2011	\$0.32	\$0.34	\$0.42	\$0.10	\$0.77

## Section 9 Conclusion

The MMU continues to conclude that the results of the Regulation Market are not competitive.<sup>130</sup> The Regulation Market results are not competitive because the changes in market rules, in particular the changes to the calculation of the opportunity cost, resulted in a price greater than the competitive price in some hours, resulted in a price less than the competitive price in some hours, and because the revised market rules are inconsistent with basic economic logic and the definition of opportunity cost elsewhere in the PJM tariff. This conclusion is not based on the behavior of market participants, which remains competitive.

PJM agrees that the definition of opportunity cost should be consistent across all markets and should, in all markets, be based on the offer schedule accepted in the market. This would require a change to the definition of opportunity cost in the Regulation Market which is the change that the MMU has recommended. The MMU also agrees that the definition of opportunity cost should be consistent across all markets.

<sup>130</sup> The 2009 State of the Market Report for PJM provided the basis for this recommendation. The 2009 State of the Market Report for PJM summarized the history of the issues related to the Regulation Market. See the 2009 State of the Market Report for PJM, Volume II, Section 6, "Ancillary Service Markets."

The structure of each Synchronized Reserve Market has been evaluated and the MMU has concluded that these markets are not structurally competitive as they are characterized by high levels of supplier concentration and inelastic demand. (The term Synchronized Reserve Market refers only to Tier 2 synchronized reserve.) As a result, these markets are operated with market-clearing prices and with offers based on the marginal cost of producing the service plus a margin. As a result of these requirements, the conduct of market participants within these market structures has been consistent with competition, and the market performance results have been competitive. However, compliance with calls to respond to actual spinning events has been an issue. As a result, the MMU is recommending that the rules for compliance be reevaluated.

The MMU concludes that the DASR Market results were competitive in 2011, although concerns remain about economic withholding and the absence of the three pivotal supplier test in this market.

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.

While the current market design satisfies the requirements of regulation, namely that it keep the reportable metrics, CPS1 and BAAL within acceptable limits, a new market design initiative began in 2011 in response to a FERC Order.<sup>131</sup> On October 20, 2011, FERC issued Order No. 755 directing PJM and other RTOs/ISOs to modify their regulation markets so as to make use of and properly compensate a mix of fast and traditional response regulation resources.<sup>132</sup> PJM is currently working with stakeholders to develop market rules that would result in an optimal, least cost combination of fast and traditional resources. This creates market design challenges, which if resolved, could improve the regulation market.

<sup>131</sup> See 2011 State of the Market Report for PJM, "Appendix F."

<sup>132</sup> Frequency Regulation Compensation in the Organized Wholesale Power Markets, 137 FERC ¶ 61,064 (2011).

Overall, the MMU concludes that the Regulation Market results were not competitive in 2011 as a result of the identified market design changes and their implementation. The MMU is hopeful that the opportunity cost can be resolved in 2012 as part of the regulation market redesign. This conclusion is not the result of participant behavior, which was generally competitive. The MMU concludes that the Synchronized Reserve Market results were competitive in 2011. The MMU concludes that the DASR Market results were competitive in 2011.

## Section 10, Congestion and Marginal Losses

### Highlights

- Total marginal loss costs in 2011 decreased by 15.6 percent from 2010 (Volume II, Table 10-10). (See Volume II, page 271)
- Net day-ahead marginal loss costs were \$1,430.5 million in 2011 and net balancing marginal loss costs were -\$51.0 million in 2011 (Volume II, Table 10-12). (See Volume II, page 272)
- American Electric Power (AEP) was the control zone with the most marginal loss costs in 2011. AEP accounted for \$318.6 million or 23.1 percent of the \$1,379.5 million total marginal loss costs. (See Volume II, page 413)
- Monthly marginal loss costs in 2011 were lower than monthly marginal loss costs in 2010, with the exception of March and April (Volume II, Table 10-12).<sup>133</sup> (See Volume II, page 272)
- The marginal loss credits (loss surplus) decreased in 2011 to \$586.7 million compared to \$836.7 million in 2010. (Volume II, Table 10-13). (See Volume II, 273)
- Congestion costs in 2011 decreased by 29.9 percent over congestion costs in 2010 (Volume II, Table 10-17). (See Volume II, 275)
- Net day-ahead congestion costs were \$1,244.9 million in 2011 and \$1,713.1 in 2010. Net balancing congestion costs were -\$246.7 million in 2011 (Volume II, Table 10-18) and -\$289.5 million in 2010. (See Volume II, 276)
- Monthly congestion costs in 2011 were lower than monthly congestion costs in 2010, with the exception of January and March (Volume II, Table 10-19 and Table 10-20). (See Volume II, 277)

### Recommendations

- The MMU recommends that PJM conduct a detailed review of the Day-Ahead Market software in order to address the issue of occasional anomalous loss factors and their effect on the day-ahead market results.

<sup>133</sup> See the 2010 State of the Market Report for PJM, Volume I, "Energy Market, Part 1," Table 2-58.

## Overview

### Marginal Loss Cost

Before June 1, 2007, the PJM economic dispatch and LMP models did not include marginal losses. The losses were treated as a static component of load, and the physical nature and location of power system losses were ignored. The PJM Tariff required implementation of marginal loss modeling when required technical systems became available. On June 1, 2007, PJM began including marginal losses in economic dispatch and LMP models.<sup>134</sup> The primary benefit of a marginal loss calculation is that it more accurately models the physical reality of power system losses, which permits increased efficiency and more optimal asset utilization. Marginal loss modeling creates a separate marginal loss price for every location on the power grid. This marginal loss price (MLMP) is a component of LMP that is charged to load and credited to generation. Total network losses are determined by using a linearized approximation model based on the loss sensitivities to location-specific changes in power injection and withdrawal. Average losses are then calculated from total losses.

Total marginal loss costs equal net marginal loss costs plus explicit marginal loss costs plus net inadvertent loss costs. Net marginal loss costs equal load loss payments minus generation loss credits. Explicit marginal loss costs are the net marginal loss costs associated with point-to-point energy transactions. Net inadvertent loss costs are the losses associated with hourly difference between the net actual energy flow and the net scheduled energy flow into or out of the PJM control area in that hour.<sup>135</sup> Unlike the other categories of marginal loss accounting, inadvertent loss costs are common costs not directly attributable to specific participants. Inadvertent related loss costs are distributed to load on a load ratio basis. Each of these categories of marginal loss costs is comprised of day-ahead and balancing marginal loss costs. Day-ahead marginal loss costs are based on day-ahead MWh priced at the marginal loss price component of Locational Marginal Price (LMP) while balancing marginal loss costs are based on deviations between day-ahead and real-time MWh priced at the marginal loss price component of Locational Marginal Price (LMP) in the Real-Time Energy Market.

Marginal loss charges can be positive or negative with respect to the reference bus. If an increase in load at a bus would decrease losses, the marginal loss component of LMP of that bus will be negative. If an increase in generation at a bus would result in an increase in losses, the marginal loss component of that bus will be negative. If an increase of load at a bus would increase losses, the marginal loss component of LMP at that bus will be positive. If an increase in generation at a bus results in a decrease of system losses, then the marginal loss component of LMP at that bus will be positive.

Day-ahead marginal loss charges and credits are based on MWh and LMP in the Day-Ahead Energy Market. Balancing marginal loss charges and credits are based on the load or generation deviations between the Day-Ahead and Real-Time Energy Markets and LMP in the Real-Time Energy Market. If a participant has real-time generation or load that is greater than its day-ahead generation or load then the deviation will be positive. If there is a positive load deviation at a bus where the real-time LMP has a positive marginal loss component, positive balancing marginal loss costs will result. Similarly, if there is a positive load deviation at a bus where real-time LMP has a negative marginal loss component, negative balancing marginal loss costs will result. If a participant has real-time generation or load that is less than its day-ahead generation or load then the deviation will be negative. If there is a negative load deviation at a bus where real-time LMP has a positive marginal loss component, negative balancing marginal loss costs will result. Similarly, if there is a negative load deviation at a bus where real-time LMP has a positive marginal loss component, negative balancing marginal loss costs will result.

Marginal loss credits or loss surplus is the remaining loss amount from overcollection of marginal losses, after accounting for net energy charges and residual market adjustments, that is paid back in full to load and exports on a load ratio basis. Marginal loss credits are calculated as the day-ahead and balancing transmission loss charges paid by all customer accounts each hour, plus the spot market energy value of the actual transmission loss MWh during that hour, plus residual net market adjustments in that hour.<sup>136</sup> Residual net market

<sup>134</sup> For additional information, see OATT Section 3.4.

<sup>135</sup> OA. Schedule 1 (PJM Interchange Energy Market) §3.7

<sup>136</sup> See PJM. "Manual 28: Operating Agreement Accounting," Revision 39 (January 1, 2008). Note that the over collection is not calculated by subtracting the prior calculation of average losses from the calculated total marginal losses.

adjustments are common costs, not directly attributable to specific participants, that are deducted from total marginal loss credits before marginal loss credits are distributed on a load weighted ratio basis. Residual market adjustments consist of the Known Day-Ahead Error Value (KDAEV), day-ahead loss MW congestion value and balancing loss MW congestion value. KDAEV are costs associated with MW imbalances created by discontinuities in, and adjustments to, the day-ahead market solution. The day-ahead and balancing loss congestion values are congestion costs associated with loss related MW.

- **Total Marginal Loss Costs.** Total marginal loss charges decreased by \$255.3 million or 15.6 percent, from \$1,634.8 million in 2010 to \$1,379.5 million in 2011. Day-ahead marginal loss costs decreased by \$235.1 million or 14.1 percent, from \$1,665.6 million in 2010 to \$1,430.5 million in 2011. Balancing marginal loss costs decreased by \$20.3 million or 65.9 percent from -\$30.7 million in 2010 to -\$51.0 million in 2011. On June 1, 2011, PJM integrated the American Transmission Systems, Inc. (ATSI) Control Zone. The metrics reported in this section treat ATSI as part of MISO for the period from January through May and as part of PJM for the period from June through December.
- **Monthly Marginal Loss Costs.** Fluctuations in monthly marginal loss costs continued to be substantial. In 2011, these differences were driven by varying load and energy import levels, different patterns of generation and weather-induced changes in demand. Monthly marginal loss costs in 2011 ranged from \$70.6 million in December to \$213.7 million in July.
- **Marginal Loss Credits.** Marginal Loss Credits are calculated as total net energy charges (total energy charges minus total energy credits) plus total net marginal loss charges (total marginal loss charges minus total marginal loss credits plus inadvertent and residual net market adjustments). Marginal loss credit or loss surplus is the remaining loss amount from overcollection of marginal losses, after accounting for net energy charges and residual market adjustments that is paid back in full to load and exports on a load ratio basis. The marginal loss

credits decreased by \$250 million or 29.9 percent, from \$836.7 million in 2010 to \$586.7 million in 2011.

- **Zonal marginal loss costs.** In 2011, zonal marginal loss costs ranged from \$3.2 million in RECO to \$318.6 million in AEP. Compared to 2010, 2011 had a decrease in marginal loss costs across the PJM control zones, except PECO and DAY control zones. Total marginal loss costs in PJM in 2011 also changed due to the addition of the ATSI Control Zone, which accounted for \$19.3 million or 1.4 percent of the total marginal loss costs.<sup>137</sup>

## Congestion Cost

Total congestion costs equal net congestion costs plus explicit congestion costs plus net inadvertent congestion costs. Net congestion costs equal load congestion payments minus generation congestion credits. Explicit congestion costs are the net congestion costs associated with point-to-point energy transactions. Net inadvertent congestion costs are the congestion costs associated with hourly difference between the net actual energy flow and the net scheduled energy flow into or out of the PJM control area in that hour. Unlike the other categories of congestion cost accounting, inadvertent congestion costs are common costs not directly attributable to specific participants. Inadvertent related congestion costs are distributed to load on a load ratio basis. Each of these categories of congestion costs is comprised of day-ahead and balancing congestion costs. Day-ahead congestion costs are based on day-ahead MWh while balancing congestion costs are based on deviations between day-ahead and real-time MWh priced at the congestion price in the Real-Time Energy Market.

Congestion charges can be both positive and negative. When a constraint binds, the price effects of that constraint vary. The system marginal price (SMP) is uniform for all areas, while the congestion components of Locational Marginal Price (LMP) will either be positive or negative in a specific area, meaning that actual LMPs are above or below the SMP.<sup>138</sup> If an area is downstream from the constrained element, the area will experience positive congestion costs. If an area is upstream from the

<sup>137</sup> See the 2011 *State of the Market Report for PJM*, Volume II, Appendix G, "Congestion and Marginal Losses," at "Zonal Marginal Loss Costs."

<sup>138</sup> The SMP is the price of the distributed load reference bus. The price at the reference bus is equivalent to the five minute real-time or hourly day-ahead load weighted PJM LMP.

constrained element, the area will experience negative congestion costs.

Day-ahead congestion charges and credits are based on MWh and LMP in the Day-Ahead Energy Market. Balancing congestion charges and credits are based on load or generation deviations between the Day-Ahead and Real-Time Energy Markets and LMP in the Real-Time Energy Market. If a participant has real-time generation or load that is greater than its day-ahead generation or load then the deviation will be positive. If there is a positive load deviation at a bus where real-time LMP has a positive congestion component, positive balancing congestion costs will result. Similarly, if there is a positive load deviation at a bus where real-time LMP has a negative congestion component, negative balancing congestion costs will result. If a participant has real-time generation or load that is less than its day-ahead generation or load then the deviation will be negative. If there is a negative load deviation at a bus where real-time LMP has a positive congestion component, negative balancing congestion costs will result. Similarly, if there is a negative load deviation at a bus where real-time LMP has a positive congestion component, negative balancing congestion costs will result.

- **Total Congestion.** Total congestion costs decreased by \$425.4 million or 29.9 percent, from \$1,423.6 million in 2010 to \$998.2 million in 2011.<sup>139</sup> Day-ahead congestion costs decreased by \$468.2 million or 27.3 percent, from \$1,713.1 million in 2010 to \$1,244.9 million in 2011. Balancing congestion costs increased by \$42.8 million or 14.8percent from -\$289.5 million in 2010 to -\$246.7 million in 2011. On June 1, 2011, PJM integrated the American Transmission Systems, Inc. (ATSI) Control Zone. The metrics reported in this section treat ATSI as part of MISO for the period from January through May and as part of PJM for the period from June through December.

**Table 15 Total annual PJM congestion (Dollars (Millions)): Calendar years 1999 to 2011**

	Congestion Charges	Percent Change	Total PJM Billing	Percent of PJM Billing
1999	\$65	NA	NA	NA
2000	\$132	103.1%	\$2,300	5.7%
2001	\$271	105.3%	\$3,400	8.0%
2002	\$453	67.2%	\$4,700	9.6%
2003	\$464	2.4%	\$6,900	6.7%
2004	\$750	61.7%	\$8,700	8.6%
2005	\$2,092	178.8%	\$22,630	9.2%
2006	\$1,603	(23.4%)	\$20,945	7.7%
2007	\$1,846	15.1%	\$30,556	6.0%
2008	\$2,117	14.7%	\$34,306	6.2%
2009	\$719	(66.0%)	\$26,550	2.7%
2010	\$1,424	98.0%	\$34,770	4.1%
2011	\$998	(29.9%)	\$35,887	2.8%
Total	\$12,933	NA	\$231,644	5.6%

- **Monthly Congestion.** Fluctuations in monthly congestion costs continued to be substantial. In 2011, these differences were driven by varying load and energy import levels, different patterns of generation, weather-induced changes in demand and variations in congestion frequency on constraints affecting large portions of PJM load. Monthly congestion costs in 2011 ranged from \$35.0 million in May to \$241.6 million in January.
- **Congestion Component of Locational Marginal Price (LMP).** To provide an indication of the geographic dispersion of congestion costs, the congestion component of LMP (CLMP) was calculated for control zones in PJM. Price separation among eastern, southern and western control zones in PJM was primarily a result of congestion on the AP South interface, the 5004/5005 interface, the Belmont transformer, West Interface, and the AEP-Dominion interface.
- **Congested Facilities.** Congestion frequency continued to be significantly higher in the Day-Ahead Market than in the Real-Time Market in 2011.<sup>140</sup> Day-ahead congestion frequency increased by 45.8 percent from 106,253 congestion event hours in 2010 to 154,868 congestion event hours in 2011. Day-ahead, congestion-event hours decreased on internal PJM interfaces while congestion-event hours increased on transmission lines, transformers and reciprocally coordinated flowgates between PJM and the MISO.

<sup>139</sup> The total zonal congestion numbers were calculated as of March 2, 2012 and are, based on continued PJM billing updates, subject to change.

<sup>140</sup> In order to have a consistent metric for real-time and day-ahead congestion frequency, real-time congestion frequency is measured using the convention that an hour is constrained if any of its component five-minute intervals is constrained.

Table 16 Congestion summary (By facility type): Calendar year 2011

Type	Congestion Costs (Millions)										
	Day Ahead				Balancing				Event Hours		
	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Flowgate	(\$110.1)	(\$215.5)	\$12.0	\$117.4	\$8.4	\$22.9	(\$88.5)	(\$103.0)	\$14.4	23,982	7,385
Interface	\$64.0	(\$395.3)	(\$10.7)	\$448.7	\$37.7	\$38.3	\$7.1	\$6.4	\$455.1	8,988	1,803
Line	\$46.7	(\$343.6)	\$38.4	\$428.7	\$23.2	\$51.2	(\$67.1)	(\$95.1)	\$333.6	88,573	9,252
Other	(\$0.5)	(\$4.7)	\$0.6	\$4.9	\$2.2	\$4.6	(\$0.4)	(\$2.8)	\$2.0	1,227	248
Transformer	\$35.1	(\$181.2)	\$21.0	\$237.3	\$3.3	\$14.5	(\$39.7)	(\$50.9)	\$186.4	32,098	3,780
Unclassified	\$1.1	(\$1.5)	\$5.4	\$8.0	\$1.2	\$0.3	(\$1.4)	(\$0.5)	\$7.5	NA	NA
Total	\$36.2	(\$1,141.8)	\$66.9	\$1,245.0	\$75.9	\$131.9	(\$190.0)	(\$246.0)	\$999.0	154,868	22,468

Real-time congestion frequency decreased by 0.4 percent from 23,422 congestion event hours in 2010 to 22,468 congestion event hours in 2011. Real-time, congestion-event hours decreased on the internal PJM interfaces and transmission lines, while congestion-event hours increased on transformers and reciprocally coordinated flowgates between PJM and MISO.

Facilities were constrained in the Day-Ahead Market more frequently than in the Real-Time Market. The Day-Ahead market is consequently more-frequent constrained conditions compared to its corresponding Real-Time Market. During 2011, for only 5.6 percent of Day-Ahead Market facility constrained hours were the same facilities also constrained in the Real-Time Market. During 2011, for 38.0 percent of Real-Time Market facility constrained hours, the same facilities were also constrained in the Day-Ahead Market.

The AP South Interface was the largest contributor to congestion costs in 2011. With \$238.9 million in total congestion costs, it accounted for 23.9 percent of the total PJM congestion costs in 2011. The top five constraints in terms of congestion costs together contributed \$466.2 million, or 46.7 percent, of the total PJM congestion costs in 2011. The top five constraints were the AP South interface, the 5004/5005 interface, West interface, the Belmont transformer and the AEP – Dominion interface.

- **Zonal Congestion.**<sup>141</sup> Measured in terms of the total congestion bill, calculated by subtracting generation congestion credits from load congestion payments plus explicit congestion costs by zone, ComEd was

the most congested zone in 2011.<sup>142</sup> ComEd had -\$1,007.3 million in total load charges, -\$1,277.3 million in total generation credits and -\$30.9 million in explicit congestion, providing \$239.0 million in total net congestion charges, reflecting significant local congestion between local generation and load, despite being on the upstream side of system wide congestion patterns. The Electric Junction – Nelson transmission line, Crete – St. Johns flowgate (a reciprocally coordinated flowgate between PJM and MISO), AP South interface, East Frankfort – Crete transmission line and the Bunsonville – Eugene flowgate contributed \$104.7 million, or 43.8 percent of the total ComEd Control Zone congestion costs.

Similarly, the AEP Control Zone recorded the second highest congestion cost in PJM in 2011, with \$195.1 million. The AP South interface contributed \$33.1 million, or 17.0 percent of the total AEP Control Zone congestion cost in 2011. The AP Control Zone recorded the third highest congestion cost in PJM in 2011, with a cost of \$143.9 million. The AP South interface contributed \$63.9 million, or 44.4 percent of the total AP Control Zone congestion cost in 2011. The control zones in the Western (AEP, AP, ATSI, ComEd, DAY and DLCO) and Southern (Dominion) regions accounted for \$737.2 million, or 73.9 percent of congestion cost and the control zones in the Eastern region accounted for \$261.0 million or 26.1 percent of congestion cost.

- **Ownership.** In 2011, financial companies as a group were net recipients of congestion credits, and physical companies were net payers of congestion charges. In 2011, financial companies received

141 Tables reporting zonal congestion have been moved from this section of the report to Appendix G. See the 2011 State of the Market Report for PJM, Volume II, Appendix G, "Congestion and Marginal Losses."

142 The total zonal congestion numbers were calculated as of March 2, 2012 and are, based on continued PJM billing updates, subject to change. As of March 2, 2012, the total zonal congestion related numbers presented here differed from the March 2, 2012 PJM totals by \$0.72 Million, a discrepancy of 0.07 percent (.0007).



\$108.2 million in net congestion credits, a decrease of \$60.3 million or 35.8 percent compared to 2010. In 2011, physical companies paid \$1,107.2 million in net congestion charges, a decrease of \$484.9 million or 30.4 percent compared to 2010.

## Section 10 Conclusion

Marginal losses are incremental change in real system power losses caused by changes in system load and generation patterns. Total marginal loss costs decreased by \$255.3 million or 15.6 percent, from \$1,634.8 million in 2010 to \$1,379.5 million in 2011. Marginal loss costs were significantly higher in the Day-Ahead Market than the Real-Time Market.

The net marginal loss bill is calculated by subtracting the generation loss credits from the sum of load loss charges, net explicit loss charges and net inadvertent loss charges. Since the net marginal bill is calculated on the basis of marginal, rather than average losses, there is an overcollection of marginal loss related costs. This overcollection, net of total energy charges and residual market adjustments<sup>143</sup>, is the source of marginal loss credits. Marginal loss credits are fully distributed back to load and exports. Marginal loss credits were \$586.7 million in 2011.

Congestion reflects the underlying characteristics of the power system, including the nature and capability of transmission facilities, the cost and geographical distribution of generation facilities and the geographical distribution of load. Total congestion costs decreased by \$425.4 million or 29.9 percent, from \$1,423.6 million in 2010 to \$998.2 million in 2011. Congestion costs were significantly higher in the Day-Ahead Market than in the Real-Time Market. Congestion frequency was also significantly higher in the Day-Ahead Market than in the Real-Time Market.

ARRs and FTRs served as an effective, but not total, offset against congestion. ARR and FTR revenues offset 96.8 percent of the total congestion costs in the Day-Ahead Energy Market and the balancing energy market within

PJM for the 2010 to 2011 planning period.<sup>144</sup> During the first seven months of the 2011 to 2012 planning period, total ARR and FTR revenues offset more than 100 percent of the congestion costs within PJM. FTRs were paid at 88.1 percent of the target allocation level for the 12-month period of the 2010 to 2011 planning period, and at 84.9 percent of the target allocation level for the first seven months of the 2011 to 2012 planning period.<sup>145</sup> Revenue adequacy, measured relative to target allocations for a planning period is not final until the end of the period.

The congestion metric requires careful review when considering the significance of congestion. The net congestion bill is calculated by subtracting generating congestion credits from load congestion payments. The logic is that increased congestion payments by load are offset by increased congestion revenues to generation, for the area analyzed. Net congestion, which includes both load congestion payments and generation congestion credits, is not a good measure of the congestion costs paid by load from the perspective of the wholesale market.<sup>146</sup> While total congestion costs represent the overall charge or credit to a zone, the components of congestion costs measure the extent to which load or generation bear total congestion costs. Load congestion payments, when positive, measure the total congestion cost to load in an area. Load congestion payments, when negative, measure the total congestion credit to load in an area. Negative load congestion payments result when load is on the lower priced side of a constraint or constraints. For example, congestion across the AP South interface means lower prices in western control zones and higher prices in eastern and southern control zones. Load in western control zones will benefit from lower prices and receive a congestion credit (negative load congestion payment). Load in the eastern and southern control zones will incur a congestion charge (positive load congestion payment). The reverse is true for generation congestion credits. Generation congestion credits, when positive, measure the total congestion credit to generation in an area. Generation congestion credits, when negative, measure the total

<sup>143</sup> Residual net market adjustments are common costs, not directly attributable to specific participants, that are deducted from total marginal loss credits before marginal loss credits are distributed on a load weighted ratio basis. Residual market adjustments consist of the Known Day-Ahead Error Value (KDAEV), day-ahead loss MW congestion value and balancing loss MW congestion value. KDAEV are costs associated with MW imbalances created by discontinuities in, and adjustments to, the day-ahead market solution. The day-ahead and balancing loss congestion values are congestion costs associated with loss related MWs.

<sup>144</sup> See the 2011 State of the Market Report for PJM, Section 12, "Financial Transmission and Auction Revenue Rights," at Table 12-36, "ARR and FTR congestion hedging: Planning periods 2010 to 2011 and 2011 to 2012."

<sup>145</sup> See the 2011 State of the Market Report for PJM, Section 12, "Financial Transmission and Auction Revenue Rights," at Table 12-22, "Monthly FTR accounting summary (Dollars (Millions)): Planning periods 2010 to 2011 and 2011 to 2012"

<sup>146</sup> The actual congestion payments by retail customers are a function of retail ratemaking policies and may or may not reflect an offset for congestion credits.

congestion cost to generation in an area. Negative generation congestion credits are a cost in the sense that revenues to generators in the area are lower, by the amount of the congestion cost, than they would have been if they had been paid LMP without a congestion component, the total of system marginal price and the loss component. Negative generation congestion credits result when generation is on the lower priced side of a constraint or constraints. For example, congestion across the AP South interface means lower prices in the western control zones and higher prices in the eastern and southern control zones. Generation in the western control zones will receive lower prices and incur a congestion charge (negative generation congestion credit). Generation in the eastern and southern control zones will receive higher prices and receive a congestion credit (positive generation congestion credit).

As an example, total congestion costs in PJM in 2011 were \$998.2 million, which was comprised of load congestion payments of \$112.2 million, negative generation credits of \$1,009.9 million and negative explicit congestion of \$123.8 million.

## Section 11, Generation and Transmission Planning

### Highlights

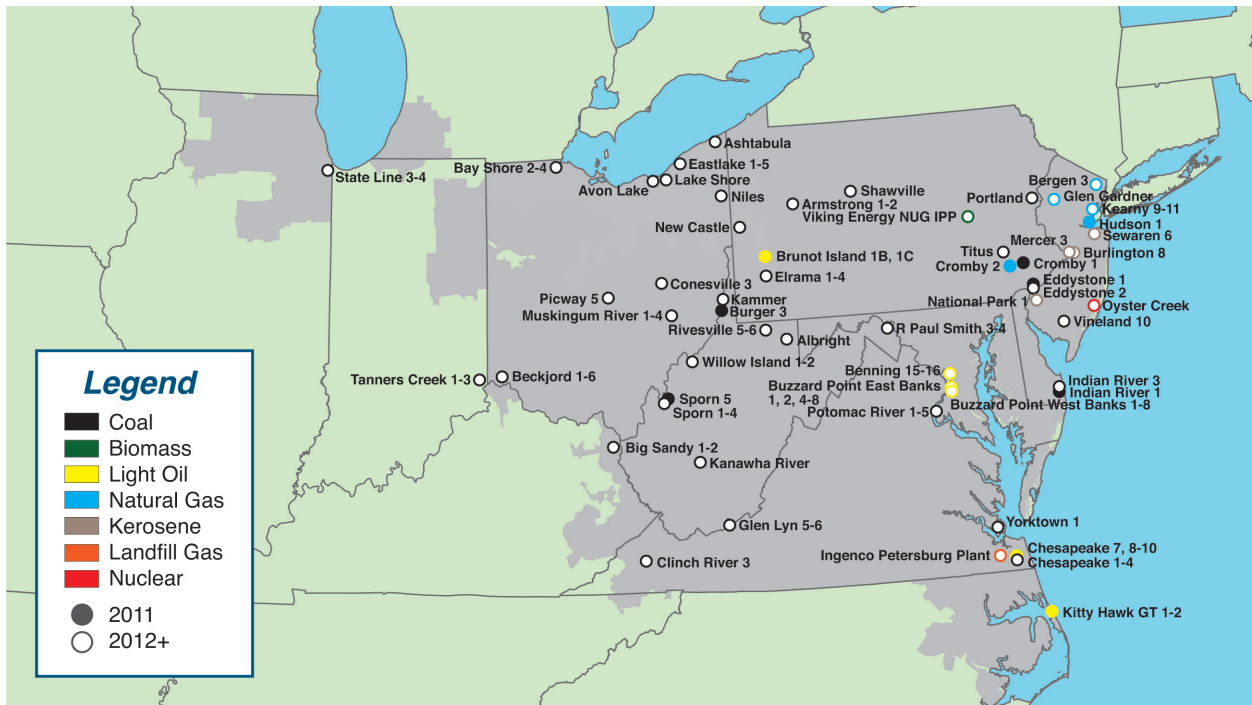
- At December 31, 2011, 90,725 MW of capacity were in generation request queues for construction through 2018, compared to an average installed capacity of 180,000 MW in 2011 including the June 1, 2011, ATSI integration. Wind projects account for approximately 37,792 MW, 41.7 percent of the capacity in the queues, and combined-cycle projects account for 34,138 MW, 37.6 percent of the capacity in the queues. (See Volume II, 286)
- Five large plants (over 500 MW) began generating in PJM in 2011. These include York Energy Center in the PECO zone, Bear Garden Generating Station in the Dominion zone, Longview Power in the APS zone, Dresden Energy Facility in the AEP zone, and Fremont Energy Center in the ATSI zone.<sup>147</sup> This is the first time since 2006 that a plant rated at more than 500 MW has come online in PJM. Overall, 5,008 MW of nameplate capacity were added in PJM in 2011 (excluding the integration of the ATSI zone), the most since 2002. (See Volume II, 286)
- A total of 1,322.3 MW of generation capacity retired in 2011, and it is expected that a total of 18,886 MW will have retired from 2011 through 2019, with most of this capacity retiring by the end of 2015. Units planning to retire in 2012 make up 7,189 MW, or 41 percent of all planned retirements. (See Volume II, 291)

### Recommendations

- The MMU recommends that PJM continue its efforts to find ways to modify the generation and transmission interconnection process to minimize the uncertainty and improve the efficiency of the process so as to eliminate any inappropriate barriers to the entry of new generation.
- The MMU recommends that PJM continue to incorporate the principle that the goal of transmission planning should be the incorporation of transmission investment decisions into market driven processes as much as possible.

<sup>147</sup> Fremont Energy Center entered PJM after the June 1, 2011 integration of ATSI, and is included in the 5,008 MW of nameplate capacity reported above.

Figure 15 Unit retirements in PJM Calendar year 2011 through 2019



- The MMU recommends that PJM propose modifications to the transmission planning process that would limit significant changes in the status of major transmission projects after they have been approved, and thus limit the uncertainty imposed on markets by the use of evaluation criteria that are very sensitive to changes in forecasts of economic variables.

## Overview

### Planned Generation and Retirements

- **Planned Generation.** At December 31, 2011, 90,725 MW of capacity were in generation request queues for construction through 2018, compared to an average installed capacity of 180,000 MW in 2011 including the June 1, 2011, ATSI integration. Wind projects account for approximately 37,792 MW, 41.7 percent of the capacity in the queues, and combined-cycle projects account for 34,138 MW, 37.6 percent of the capacity in the queues.
- **New Generation.** Five large plants (over 500 MW) began generating in PJM in 2011. These include

York Energy Center in the PECO zone, Bear Garden Generating Station in the Dominion zone, Longview Power in the APS zone, Dresden Energy Facility in the AEP zone, and Fremont Energy Center in the ATSI zone.<sup>148</sup> This is the first time since 2006 that a plant rated at more than 500 MW has come online in PJM. Overall, 5,008 MW of nameplate capacity were added in PJM in 2011 (excluding the integration of the ATSI zone), the most since 2002.

- **Generation Retirements.** A total of 1,322.3 MW of generation capacity retired in 2011, and it is expected that a total of 18,886 MW will have retired from 2011 through 2019, with most of this capacity retiring by the end of 2015. Units planning to retire in 2012 make up 7,189 MW, or 41 percent of all planned retirements. Overall, 5,191.1 MW, or 29.6 percent of all retirements, are expected in the AEP zone.

<sup>148</sup> Fremont Energy Center entered PJM after the June 1, 2011 integration of ATSI, and is included in the 5,008 MW of nameplate capacity reported above.

- **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 EMAAC and SWMAAC LDAs, the capacity mix is likely to shift to more natural gas-fired combined cycle (CC) and combustion turbine (CT) capacity. Elsewhere in the PJM footprint, continued reliance on steam (mainly coal) seems likely, although changes in environmental regulations have had an impact on coal units throughout the footprint.

### Generation and Transmission Interconnection Planning Process

- Any entity (developer or applicant) that requests interconnection of a generating facility, including increases to the capacity of an existing generating unit, or requests interconnection of a merchant transmission facility, must follow the process defined in the PJM tariff to obtain interconnection service.<sup>149</sup> The process is complex and time consuming as a result of the nature of the required analyses. The cost and time associated with interconnecting to the grid potentially create barriers to entry by creating uncertainty for potential entrants.
- The queue contains a substantial number of projects that are not likely to be built. These projects may also create barriers to entry for projects that would otherwise be completed by creating uncertainty and increasing interconnection costs.

### Backbone Facilities

- PJM baseline transmission projects are implemented to resolve reliability criteria violations. PJM backbone transmission projects are a subset of significant baseline projects. The backbone projects are typically intended to resolve a wide range of reliability criteria violations and congestion issues and have substantial impacts on energy and capacity markets. The current backbone projects are: Mount Storm – Doubs; Jacks Mountain; Mid-Atlantic Power Pathway (MAPP); Potomac – Appalachian Transmission Highline (PATH); and Susquehanna –

Roseland. The total planned costs for all of these projects are approximately five billion dollars.

### Economic Planning Process

- **Transmission and Markets.** As a general matter, transmission investments have not been fully incorporated into competitive markets. The construction of new transmission facilities can have significant impacts on energy and capacity markets, but there is no market mechanism in place that would require direct competition between transmission and generation to meet loads in an area. PJM has taken a first step towards integrating transmission investments into the market through the use of economic evaluation metrics.<sup>150</sup> The goal of transmission planning should be the incorporation of transmission investment decisions into market driven processes as much as possible.
- **Competitive Grid Development.** In Order No. 1000, the FERC requires that each public utility transmission provider (including PJM) remove from its FERC approved tariff and agreements, as necessary and subject to certain limitations, a federal right of first refusal (ROFR) for certain new transmission projects.<sup>151,152</sup> A key limitation is the ability to retain ROFR for upgrades to the existing transmission infrastructure.

<sup>149</sup> OATT Parts IV & VI.

<sup>150</sup> See 126 FERC ¶ 61,152 (2009) (final approval for an approach with predefined formulas for determining whether a transmission investment passes the cost-benefit test including explicit accounting for changes in production costs, the costs of complying with environmental regulations, generation availability trends and demand-response trends), *order on reh'g*, 123 FERC ¶ 61,051 (2008).

<sup>151</sup> *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, FERC Stats. & Regs. ¶31,323 (2011).

<sup>152</sup> *Id.* at PP 313–322.

## Section 12, Financial Transmission Rights and Auction Revenue Rights.

### Highlights

- On June 1, 2011, the American Transmission Systems, Inc. (ATSI) Control Zone joined the PJM footprint. Network Service Users and Firm Transmission Customers in the ATSI Control Zone participated in the Annual ARR Allocation and the Annual FTR Auction for the 2011 to 2012 planning period. (See Volume II, 305)
- The total cleared FTR buy bids from the Monthly Balance of Planning Period FTR Auctions for the first seven months of the 2011 to 2012 planning period increased by 47 percent from 1,092,956 MW to 1,589,989 MW compared to the first seven months of the 2010 to 2011 planning period. (See Volume II, 312)
- FTRs were paid at 85.0 percent of the target allocation level for the full 2010 to 2011 planning period and 84.9 percent for the first seven months of the 2011 to 2012 planning period. (See Volume II, 329)
- FTR profitability is the difference between the revenue received for an FTR and the cost of the FTR. FTRs were profitable overall and were profitable for both physical and financial entities in the 2011 calendar year. Total FTR profits were \$340.3 million for physical entities and \$125.7 million for financial entities. Self scheduled FTRs were the source of \$560.5 million of the FTR profits for physical entities. Not every FTR was profitable. FTRs purchased by physical entities, but not self scheduled, were not profitable in 2011. (See Volume II, 333)
- As one of the measures to address underfunding, effective August 5, 2011, PJM no longer allows FTR buy bids to clear with a price of zero unless there is at least one constraint in the auction which affects the FTR path. (See Volume II, 320)

### Recommendations

- The MMU recommends that a detailed review of the ARR/FTR allocation and market clearing be conducted in order to better understand and address the reasons for FTR underfunding. This review should include the assumptions made in the modeling of

auctions and their basis in market developments. The MMU also recommends an explicit statement in the rules explaining the purpose and objectives of ARRs, FTRs and the appropriate level of funding of FTRs. The MMU recommends that no action to substantially modify the market design, e.g. removal of balancing congestion from the calculation of FTR revenues, be taken until the review is complete.

- The MMU recommends that when load switches among LSEs during the planning period, a proportional share of the underlying self scheduled FTRs, derived from the ARR allocation to that load, follow the load in the same manner as ARRs.

### Overview

#### Financial Transmission Rights

##### Market Structure

- **Supply.** The principal binding constraints limiting the supply of FTRs in the 2012 to 2015 Long Term FTR Auction include the Millville – Old Chapel line, approximately 40 miles northwest of Washington, D.C., and the Burr Oak Flowgate, approximately 60 miles west of Fort Wayne, IN. The principal binding constraints limiting the supply of FTRs in the Annual FTR Auction for the 2011 to 2012 planning period include the Doubs Transformer, approximately 20 miles northwest of Washington, D.C. and the Bartonville – Stephens City line, approximately 60 miles west of Washington, D.C.

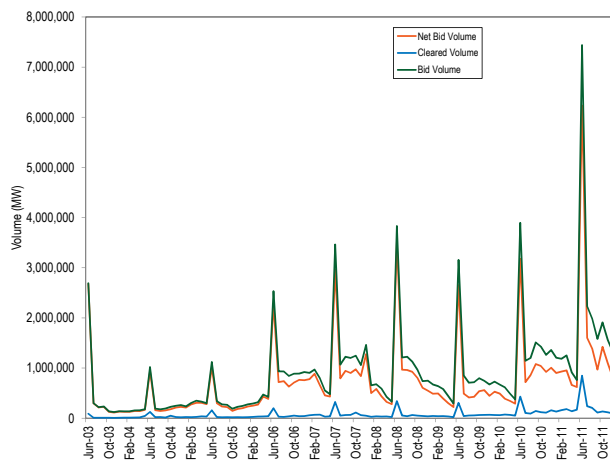
Market participants can also sell FTRs. In the 2012 to 2015 Long Term FTR Auction, total participant FTR sell offers were 251,290 MW, up from 177,540 MW during the 2011 to 2014 Long Term FTR Auction. In the Annual FTR Auction for the 2011 to 2012 planning period, total participant FTR sell offers were 337,510 MW, up from 178,428 MW during the 2010 to 2011 Annual FTR Auction. In the Monthly Balance of Planning Period FTR Auctions for the first seven months (June through December 2011) of the 2011 to 2012 planning period, total participant FTR sell offers were 3,984,782 MW, up from 2,706,728 MW for the same period during the 2010 to 2011 planning period.

- **Demand.** The PJM tariff specifies that PJM has the authority to limit the maximum number of FTR bids to 5,000 per participant for a monthly auction, or a

single round of an annual auction, if necessary to avoid related system performance issues.<sup>153</sup> On this basis, PJM currently limits the maximum number of bids that could be submitted by a participant for any individual period in an auction to 10,000 bids.

In the 2012 to 2015 Long Term FTR Auction, total FTR buy bids increased 1.3 percent from 400,222 MW to 405,504 MW. In the Annual FTR Auction total FTR buy bids and self scheduled bids increased 84.8 percent from 1,764,288 MW to 3,260,695 MW. The total FTR buy bids from the Monthly Balance of Planning Period FTR Auctions for the first seven months of the 2011 to 2012 (June through December 2011) planning period increased 42.3 percent from 8,973,645 MW, during the same time period of the prior planning period, to 12,767,075 MW.

**Figure 16 Long Term, Annual and Monthly FTR Auction bid and cleared volume: June 2003 through December 2011<sup>154</sup>**



As one of the measures to address underfunding, effective August 5, 2011, PJM no longer allows FTR buy bids to clear with a price of zero unless there is at least one constraint in the auction which affects the FTR path.

- **Credit Issues.** There were eight participants that defaulted during the 2011 calendar year and 12 default events. The average default for the 2011 calendar year was \$282,721 with a maximum default of \$2.55 million. Of all the defaults eight

were based on collateral and four were based on payments. Six of the eight defaulting participants were financial companies. All of the credit defaults were promptly cured in the 2011 calendar year.<sup>155</sup> These defaults were not related to FTR positions.

- **Credit Rules Changes.** On September 15, 2011, the FERC conditionally approved PJM's proposed revisions to its credit policy filed in compliance with FERC's Order No. 741, which required tighter credit standards for all RTOs.<sup>156</sup>

As a result of these new requirements, most PJM members complied with PJM's new minimum financial requirements effective October 1, 2011. Based on submitted information, 17 members did not meet the new requirements. Of these 17, 16 opted to reduce or discontinue their transaction activity and one did not comply, and was declared in default. These 17 members accounted for 0.1 percent of the aggregate bids in the 2011 to 2012 Annual FTR auction.<sup>157</sup>

- **Patterns of Ownership.** The ownership concentration of cleared FTR buy bids resulting from the 2011 to 2012 Annual FTR Auction was low for peak and off peak FTR obligations and moderately concentrated for 24-hour FTR obligations. The ownership concentration was also low for peak and off peak FTR buy bid options and highly concentrated for 24-hour FTR buy bid options for the same time period. The level of concentration is only descriptive and is not a measure of the competitiveness of FTR market structure as the ownership positions resulted from a competitive auction.

For the 2012 through 2015 Long Term FTR Auction, financial entities purchased 90 percent of prevailing flow FTRs and 94 percent of counter flow FTRs. In the Annual FTR Auction, planning period 2011 through 2012, financial entities purchased 56 percent of prevailing flow FTRs and 85 percent of counter flow FTRs. For the Monthly Balance of Planning Period Auctions, financial entities purchased 83 percent of prevailing flow and 90 percent of counter flow FTRs for the 2011 calendar year. Financial entities

<sup>153</sup> OA Schedule 1 § 7.3.5(d).

<sup>154</sup> The previous 3rd Quarter *State of the Market Report* did not contain volume data for Long Term FTR Auctions.

<sup>155</sup> Email to Members Committee, "PJM Settlement Member Credit Exposure – End of December 2011," January 12, 2012.

<sup>156</sup> *PJM Interconnection, LLC*, 136 FERC ¶61,190 (September 15th Order); see also *Credit Reforms in Organized Wholesale Electric Markets*, Order No. 741, FERC Stats. & Regs. ¶31,317 (2010), order on reh'g, Order No. 741-A, FERC Stats. & Regs. ¶31,320, reh'g denied, Order No. 741-B, 135 FERC ¶61,242 (2011).

<sup>157</sup> It is not possible to evaluate the impact on members which members did not report.

owned 51.5 percent of all prevailing and counter flow FTRs, including 45.8 percent of all prevailing flow FTRs and 68.3 percent of all counter flow FTRs during the same time period.

## Market Performance

- **Volume.** The 2012 to 2015 Long Term FTR Auction cleared 259,885 MW (10.8 percent of demand) of FTR buy bids, compared to 238,681 MW (12.0 percent) in the 2011 to 2014 Long Term FTR Auction. The 2012 to 2015 Long Term FTR Auction also cleared 31,288 MW (12.5 percent) of FTR sell offers, up from 12,501 MW (7.0 percent) in the 2011 to 2012 Long Term FTR Auction.

For the 2011 to 2012 planning period, the Annual FTR Auction cleared 341,726 MW (10.6 percent) of FTR buy bids, compared to 231,663 MW (13.6 percent) for the 2010 to 2011 planning period. The 2011 to 2012 Annual FTR Auction also cleared 24,960 MW (7.4 percent) of FTR sell offers for the 2011 to 2012 planning period, up from 10,315 MW (5.8 percent) for the 2010 to 2011 planning period.

For the first seven months of the 2011 to 2012 planning period, the Monthly Balance of Planning Period FTR Auctions cleared 1,589,990 MW (12.5 percent) of FTR buy bids and 427,443 MW (10.7 percent) of FTR sell offers.

- **Price.** In the 2012 to 2015 Long Term FTR Auction, more Long Term FTRs were purchased for less than \$1 than in the prior Long Term Auction. The weighted-average price for 24-hour buy bids in the Long Term FTR Auction rose from -\$0.16 to \$0.36 per MW. Counter flow buy bid prices were negative, but greater in absolute value, than prevailing flow FTR bid prices.

For the 2011 to 2012 Annual Auction, slightly fewer FTRs were purchased for less than \$1 than in the prior Annual Auction. The weighted-average price for 24-hour buy bid obligations in the 2011 to 2012 planning period was \$0.68 per MW, up from \$0.43 in the 2010 to 2011 planning period.

The weighted-average buy-bid FTR price in the Monthly Balance of Planning Period FTR Auctions for the first seven months of the 2011 to 2012 planning period was \$0.13, down from \$0.17 per MW in the first seven months of the 2010 to 2011 planning period.

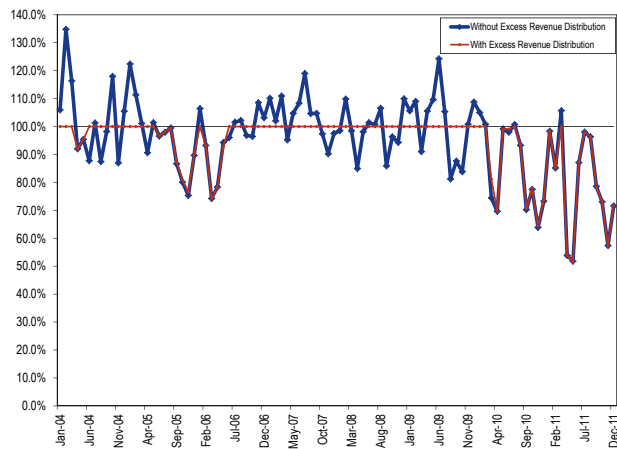
- **Revenue.** The 2012 to 2015 Long Term FTR Auction generated \$20.5 million of net revenue for all FTRs, down from \$49.8 million in the 2011 to 2014 Long Term FTR Auction and the lowest net revenue since the Long Term FTR Auction's inception. This drop in net revenue is largely due to a 106.2 percent increase in revenue for sell offers from the 2011 to 2014 Long Term FTR Auction, along with a 29.5 percent drop in prevailing flow FTR buy bids.

The 2011 2012 planning period Annual FTR Auction generated \$1,029.7 million of net revenue for all FTRs, down from \$1,049.8 million for the 2010 to 2011 planning period.

The Monthly Balance of Planning Period FTR Auctions generated \$21.9 million in net revenue for all FTRs for the first seven months of the 2011 to 2012 planning period, up from \$16.7 million for the same time period in the 2010 to 2011 planning period.

- **Revenue Adequacy.** FTRs were paid at 85.0 percent of the target allocation for the 2010 to 2011 planning period. FTRs were paid at 84.9 percent of the target allocation level for the first seven months of the 2011 to 2012 planning period. Congestion revenues are allocated to FTR holders based on FTR target allocations. PJM collected \$570.3 million of FTR revenues during the first seven months of the 2011 to 2012 planning period and \$1,430.7 million during the 2010 to 2011 planning period. For the first seven months of the 2011 to 2012 planning period, the top sink and top source with the highest positive FTR target allocations were AEP without Mon Power and the Western Hub. Similarly, the top sink and top source with the largest negative FTR target allocations were AEP without Mon Power and Kammer.

**Figure 17 FTR payout ratio with adjustments by month, excluding and including excess revenue distribution: January 2004 to December 2011**



- **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 \$340.3 million in profits for physical entities, of which \$560.5 million was from self scheduled FTRs, and \$125.7 million for financial entities. FTR profits generally increased in the summer and winter months when congestion was higher and decreased in the shoulder months when congestion was lower. For example, prevailing flow FTRs purchased by physical entities, but not self scheduled, were not profitable in 2011. Prevailing flow FTRs, purchased by financial entities, were not profitable in 2011.

## Auction Revenue Rights

### Market Structure

- **Supply.** ARR supply is limited by the capability of the transmission system to simultaneously accommodate the set of requested ARRs and the numerous combinations of feasible ARRs. The principal binding constraints that limited supply in the annual ARR allocation for the 2011 to 2012 planning period were the South Mahwah – Waldwick line, in northern New Jersey, and the East Frankfort – Crete line, approximately 20 miles south of Chicago, IL. Long Term ARRs are in effect for 10 consecutive planning periods and are available in Stage 1A of the annual ARR allocation. Residual

ARRs are available to holders with prorated Stage 1A or 1B ARRs if additional transmission capability is added during the planning period.

- **Demand.** Total requested volume in the annual ARR allocation was 148,538 MW for the 2011 to 2012 planning period with 64,160 MW requested in Stage 1A, 22,208 MW requested in Stage 1B and 57,053 MW requested in Stage 2. This is up from 135,614 MW for the 2010 to 2011 planning period with 61,793 MW requested in Stage 1A, 37,850 MW requested in Stage 1B and 45,971 MW requested in Stage 2. The ATSI integration accounted for 5,434 MW of increased demand. The total ARR volume allocated is limited by the amount of network service and firm point-to-point transmission service.
- **ARR Reassignment for Retail Load Switching.** There were 24,531 MW of ARRs associated with approximately \$388,700 of revenue that were reassigned in the first seven months of the 2011 to 2012 planning period. There were 56,296 MW of ARRs associated with approximately \$1,043,700 of revenue that were reassigned for the full twelve months of the 2010 to 2011 planning period.

### Market Performance

On June 1, 2011, the American Transmission Systems, Inc. (ATSI) Control Zone was integrated into PJM. Network Service Users and Firm Transmission Customers in the ATSI Control Zone participated in the 2011 to 2012 Annual ARR Allocation. For a transitional period, those customers that receive, and pay for, firm transmission service that sources or sinks in newly integrated PJM control zones may elect to receive a direct allocation of FTRs instead of an allocation of ARRs. This transitional period covers the succeeding two Annual FTR Auctions after the integration of the new zone into PJM. In the 2011 to 2012 planning period 5,434 MW of ARRs were requested and 2,770 MW were allocated (51 percent) and 7,750 MW of directly allocated FTRs were requested while 4,189 MW were allocated (54 percent).

- **Volume.** Of 148,538 MW in ARR requests for the 2011 to 2012 planning period, 102,476 MW (69.0 percent) were allocated. Market participants self scheduled 46,017 MW (44.9 percent) of these allocated ARRs as Annual FTRs. Of 135,614 MW in ARR requests for the 2010 to 2011 planning period, 101,843 MW (75.1 percent) were allocated. Market participants



self scheduled 55,732 MW (54.6 percent) of these allocated ARR as Annual FTRs.

- **Revenue.** There are no ARR revenues. ARRs are allocated to qualifying customers because they pay for the transmission system.
- **Revenue Adequacy.** For the 2011 to 2012 planning period, the ARR target allocations were \$947.3 million while PJM collected \$1,051.8 million from the combined Long Term, Annual and Monthly Balance of Planning Period FTR Auctions through December 31, 2011, making ARRs revenue adequate. For the 2010 to 2011 planning period, the ARR target allocations were \$1,028.8 million while PJM collected \$1,066.9 million from the combined Long Term, Annual and Monthly Balance of Planning Period FTR Auctions, making ARRs revenue adequate.
- **ARR Proration.** Stage 1A ARR requests may not be prorated. Some of the requested ARRs for the 2011 to 2012 planning period were prorated in Stage 1B and Stage 2 as a result of binding transmission constraints. For the 2010 to 2011 planning period, no ARRs were prorated in Stage 1B of the annual ARR allocation.
- **ARRs and FTRs as an Offset to Congestion.** The effectiveness of ARRs as an offset to congestion can be measured by comparing the revenue received by ARR holders to the congestion costs experienced by these ARR holders in the Day-Ahead Energy Market and the balancing energy market. For the 2010 to 2011 planning period, the total revenues received by ARR holders, including self scheduled FTRs, more than covered the congestion costs experienced by these ARR holders in the Day-Ahead Energy Market and the balancing energy market. For the 2010 to 2011 planning period, the total revenues received by the holders of all ARRs and FTRs offset more than 97.3 percent of the total congestion costs within PJM. During the first seven months of the 2011 to 2012 planning period, the total revenues received by the holders of all ARRs and FTRs offset more than 100 percent of the total congestion costs within PJM.

## Section 12 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. FTR holders do not have the right to revenue adequacy.

PJM created the split between ARRs and FTRs in order to both continue to provide the appropriate protection against congestion for load, and to permit any excess transmission capacity on the system to be made available to those market participants who wished to use FTRs to speculate or to hedge positions. The FTR auctions provide market participants with the opportunity to hedge positions or to speculate and permits ARR holders to convert ARRs into FTRs. The Long Term FTR Auction, the Annual FTR Auction and the Monthly Balance of Planning Period FTR Auctions provide a market valuation of FTRs. The FTR auction results for the 2011 to 2012 planning period were competitive and succeeded in providing all qualified market participants with equal access to FTRs.

Based on the FTR target allocations, there has been significant underfunding of FTRs since the spring of 2010. Underfunding or revenue inadequacy occurs when total congestion, which is comprised of day-ahead congestion plus balancing congestion, is less than the FTR target allocation. Total congestion revenues are allocated to FTR holders based on FTR target allocations.<sup>158</sup> FTRs were paid at 85.0 percent of the target allocation level for the 2010 to 2011 planning period. FTRs were paid at 84.9 percent of the target allocation level for the first seven months of the 2011 to 2012 planning period. Revenue adequacy for a planning period is not final until the end of the period. Underfunding and revenue inadequacy are misnomers because they appear to imply that the correct answer is that revenues must fully cover congestion on FTR paths, the target allocations. There is no guarantee of full revenue adequacy for FTRs. The mechanism that has the stated intent of assuring full revenue adequacy

<sup>158</sup> PJM Financial Transmission Rights Task Force (FTRTF), <<http://pjm.com/committees-and-groups/task-forces/ftrtf.aspx>>.

for FTRs is in fact a mechanism for self funding of revenue adequacy. FTR holders themselves make up any shortfall. Rather than a revenue adequacy mechanism, this is a mechanism to ensure that revenue shortfalls on specific transmission paths are socialized among all FTR holders and that all FTR holders share in the shortfall proportionately.

PJM is attempting to meet two competing objectives in determining the level of FTRs to offer in FTR auctions. Funding FTRs is a valid objective. Maximizing the efficient usage of the transmission system by increasing the level of offered FTRs is also a valid objective. FTR underfunding reflects PJM's efforts to balance competing objectives. FTR revenue shortfalls are not evidence that there is any deficiency with PJM's approach. PJM could effectively guarantee full funding of FTRs by using more conservative assumptions in its auction model. But that would inappropriately tilt toward one end of the tradeoff between revenue sufficiency and maximizing the availability of FTRs. It is not clear whether there would be any revenue shortfalls if PJM had not created separate ARR and FTR products but had continued to assign FTRs based on the purchase of transmission service.

The reasons for recent increased shortfalls in FTR funding, identified by PJM, support the continued use of the current definition of FTR revenues, which includes balancing congestion. The reasons offered by PJM are reduced transmission capability and the difficulty of modeling Midwest Independent System Operator, Inc. ("MISO") flowgates in the FTR Auction model. These both result in over selling FTRs. Over selling FTRs creates balancing congestion, which reduces the funds available to pay FTR holders. It is appropriate that FTR holders are paid less when FTR revenues, including balancing congestion, are reduced.

Both of the cited reasons resulted in PJM selling more FTR capability in the FTR auctions than exists. This was a result of the fact that FTR auctions are run well before the time that congestion is experienced and reality does not always match the model used in the auction to define available FTRs. The difficulty in predicting flows on PJM/MISO flowgates used in market-to-market congestion management and the reduction in overall transmission capability in turn results in differences

between day-ahead models and actual experience in real time.

FTR holders do not have guarantees from PJM or PJM transmission customers that their payments would depend on modeling assumptions in the day-ahead market rather than total congestion. FTR holders cannot reasonably expect that such payments would ignore balancing congestion. It would be inappropriate to have FTR holders' revenues depend solely on modeling assumptions rather than on actual total congestion, including balancing congestion.

Underfunding is a logical consequence of overselling FTRs. When FTRs are oversold, a decline in their value can be expected. A reduction in FTR revenue sufficiency is a market signal and a correct market signal. The level of FTRs sold reflects PJM's judgment. The logical conclusion is not that underfunding must be eliminated through a change in the funding mechanism but that it is an expected consequence of the ongoing transmission upgrades on the system, the unanticipated level of congestion on MISO flowgates, and PJM's choices about the level of FTRs sold. If full funding is the goal, fewer FTRs should be sold, reflecting the reduced capability of the transmission system.

The notion that underfunding is a problem that should be solved through external subsidies depends on the assertion that FTR holders are guaranteed payments based on the definition of target allocations. Target allocations serve as a cap on FTR payments by time period and therefore define the amount of over collections that are spread to other periods. Target allocations do not establish an entitlement to any level of funding. FTR holders are not entitled to such a guarantee backed by an allocation of shortfalls to all transmission customers. FTR holders do not have a reasonable expectation of funding at that level. The valuation of FTRs by purchasers includes market risk. Market participants appropriately bear this risk and they should not be permitted to shift those risks to others. FTR holders are in position to assess the value of the FTRs that they purchase. If they are wrong, they appropriately bear the risks. It is a fundamental precept of market design that market participants should bear the risks associated with their decisions. External subsidies should not be introduced in order to attenuate that link. That would

distort incentives and correspondingly distort market decisions.

The value of FTRs is determined by the revenue available to fund them. The value of FTRs is not determined by the target allocation. FTRs are financial products which serve a number of market functions from hedging to speculation. FTRs are voluntarily purchased in the market.

It has been suggested by some market participants that balancing congestion should be paid by all transmission customers, regardless of ARR allocations. But it has not been explained why transmission customers who did not purchase FTRs should play a role in funding FTRs by absorbing balancing congestion. Nor has it been explained why creating another unavoidable uplift charge with no causal link to those paying it is superior to continuing to have the market value FTRs, and have FTR purchasers make rational decisions about how much to pay for FTRs based on expectations about available congestion revenues. The current approach results in an appropriate match between the decision maker and the result. The introduction of a subsidy financed through an uplift charge would disrupt the link between the decision maker and the result.

Until the fundamental issues underlying FTR funding can be addressed, that level of revenue sufficiency will continue to be a correct market signal. FTR holders can pay less for FTRs if they believe that their value has been reduced, or PJM can make fewer FTRs available. These are very similar outcomes.

PJM and its stakeholders identified discrepancies between auction modeling and actual system conditions as the primary drivers of the underfunding. These discrepancies included outages not modeled in the annual or monthly auctions and additional transmission switching decisions not incorporated in the model. The impact of including balancing congestion in the calculation of revenues was also noted.<sup>159</sup> Although the annual FTR auction represents the entire year, the auction model reflects the PJM system for a single point in time. PJM must evaluate transmission line outage schedules and thermal operating limits for transmission

lines for inclusion in the model for the Annual FTR Auction. FTR revenue adequacy is not guaranteed nor should it be. PJM should model the system as accurately as possible and participants should bid prices that reflect their evaluations of the expected profitability of FTRs.

The MMU recommends that a detailed review of the ARR/FTR allocation and market clearing be conducted in order to better understand and address the reasons for FTR underfunding. This review should include the assumptions made in the modeling of auctions and their basis in market developments. The MMU also recommends an explicit statement in the rules explaining the purpose and objectives of ARRs, FTRs and the appropriate level of funding of FTRs. The MMU recommends that no action to substantially modify the market design, e.g. removal of balancing congestion from the calculation of FTR revenues, be taken until the review is complete.

For the 2010 to 2011 planning period, the total revenues received by the holders of all ARRs and FTRs offset more than 97.3 percent of the total congestion costs within PJM. During the first seven months of the 2011 to 2012 planning period, the total revenues received by the holders of all ARRs and FTRs offset more than 100 percent of the total congestion costs within PJM. The ARR and FTR revenue offset results are aggregate results and all those paying congestion charges did not necessarily receive that level of offset. Aggregate numbers do not reveal the underlying distribution of ARR and FTR holders, their revenues or those paying congestion.

The MMU also recommends that when load switches among LSEs during the planning period, a proportional share of the underlying self scheduled FTRs follow the load in the same manner that ARRs do. ARRs are assigned to firm transmission service customers because these customers pay the costs of the transmission system that enables firm energy delivery. Positively valued ARRs follow load when load switches between suppliers. The self scheduled FTRs are obtained as the direct result of the ARR assignment and should therefore follow the reassignment of ARRs when load switches in order to ensure that the new LSE is in the same competitive position as the LSE that lost load.

<sup>159</sup> The Market Implementation Committee (MIC) approved the creation of the Financial Transmission Rights Task Force (FTRTF) to investigate the causes of the FTR revenue inadequacy that occurred in the 2010 to 2011 Planning Period and identify potential improvements that could be made to minimize the revenue inadequacy going forward.