# State of the Market Report for PJM

## Volume 1: Introduction

Monitoring Analytics, LLC

Independent
Market Monitor
for PJM

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# Preface

The PJM Market Monitoring Plan provides:

> The Market Monitoring Unit shall prepare and submit contemporaneously to the Commission, the State Commissions, the PJM Board, PJM Management and to the PJM Members Committee, annual state-of-the-market reports on the state of competition within, and the efficiency of, the PJM Markets, and quarterly reports that update selected portions of the annual report and which may focus on certain topics of particular interest to the Market Monitoring Unit. The quarterly reports shall not be as extensive as the annual reports. In its annual, quarterly and other reports, the Market Monitoring Unit may make recommendations regarding any matter within its purview. The annual reports shall, and the quarterly reports may, address, among other things, the extent to which prices in the PJM Markets reflect competitive outcomes, the structural competitiveness of the PJM Markets, the effectiveness of bid mitigation rules, and the effectiveness of the PJM Markets in signaling infrastructure investment. These annual reports shall, and the quarterly reports may include recommendations as to whether changes to the Market Monitoring Unit or the Plan are required.[1]

Accordingly, Monitoring Analytics, LLC, which serves as the Market Monitoring Unit (MMU) for PJM Interconnection, L.L.C. (PJM),[2] and is also known as the Independent Market Monitor for PJM (IMM), submits this *2015 State of the Market Report for PJM*.[3]

1 PJM Open Access Transmission Tariff (OATT) Attachment M (PJM Market Monitoring Plan) § VI.A. Capitalized terms used herein and not otherwise defined have the meaning provided in the OATT, PJM Operating Agreement, PJM Reliability Assurance Agreement or other tariff that PJM has on file with the Federal Energy Regulatory Commission (FERC or Commission).

2 OATT Attachment M § II(f).

3 All references to this report should refer to the source as Monitoring Analytics, LLC, and should include the complete name of the report: *2015 State of the Market Report for PJM*.

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# Introduction

## 2015 in Review

The results of the energy market, the results of the capacity market and the results of the regulation market were competitive in 2015. The PJM markets work. The PJM markets bring customers the benefits of competition. The goal of competition is to provide customers wholesale power at the lowest possible price, but no lower.

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

Competitive markets were introduced as an alternative form of regulation to ensure that wholesale power is provided at the lowest possible price. The PJM market design does not incorporate a laissez faire approach. The PJM market remains regulated. The PJM market design incorporates a variety of rules designed to help ensure competitive outcomes. When basic elements of those rules are modified, e.g. the raising of the overall $1,000 per MWh offer cap and the introduction of hourly offers in place of daily offers, it is essential that effective market power mitigation be maintained. While the three pivotal supplier test addresses local market power associated with transmission constrained markets, it does not address aggregate market power. Aggregate market power exists when generation owners have the ability to raise market prices above competitive levels in the absence of transmission constraints, for example when demand is high and market conditions are tight. A direct and effective substitute for the current market power mitigation rule limiting units to one offer per day would be to limit any hourly offer changes during the day to changes in the cost of fuel. The failure to maintain limits on aggregate market power will lead to the exercise of market power and the associated negative impacts on the competitiveness of PJM markets.

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

One of the benefits of competitive power markets is that changes in input prices and changes in the balance of supply and demand are reflected immediately in energy prices. Energy market prices in 2015 decreased by almost a third from 2014 as a combined result of lower fuel prices and lower demand. The load-weighted average real-time LMP was 31.9 percent lower in 2015 than in 2014, $36.16 per MWh versus $53.14 per MWh. The load-weighted average price in 2015 was about 20 percent lower than the average of annual prices in all years from 1999 through 2015. If fuel costs in 2015 had been the same as in 2014, holding everything else constant, the load-weighted average LMP would have been higher, $41.91 per MWh instead of the observed $36.16 per MWh, but still lower than in 2014.

The markup conduct of individual owners and units has an identifiable impact on market prices. In the Real-Time Energy Market, the adjusted markup component of LMP decreased from $3.32 in 2014 to $1.75 in 2015. The markup decreased from 6.2 percent of real-time LMP in 2014 to 4.8 percent in 2015. Although markups continued to be significant in 2015, participant behavior was evaluated as competitive because marginal units generally made offers at, or close to, their short run

marginal costs. But the markup results are a reminder that aggregate market power remains an issue when market conditions are tight and that market design choices must account for the potential to exercise aggregate market power. There are also generation owners who routinely include high markups in price based offers on some units. These markups do not affect prices under normal conditions.

The three pivotal supplier (TPS) 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. The TPS test is a flexible, targeted real-time measure of market structure which replaced the prior approach of offer capping all units required to relieve a constraint. But there are some issues with the application of mitigation when market sellers fail the TPS test. There is no tariff or manual language that defines in detail the application of the TPS test and mitigation in the Day-Ahead Energy Market and the Real-Time Energy Market. In both the Day-Ahead and Real-Time Energy Markets, generators have the ability to avoid mitigation by using varying markups in their price-based offers, offering different operating parameters in their price-based and cost-based offers, and using different fuels in their price-based and cost-based offers. These issues with mitigation can and should be resolved by simple rule changes requiring that markup be constant across price and cost offers, that there be at least one cost-based offer using the same fuel as the available price-based offer, that the price-MW pairs in the price based PLS offer be exactly equal to the price based non PLS offer, and requiring cost- based and price-based PLS offers to be at least as flexible as price-based non-PLS offers. The significance of implementing these rule changes is substantially increased with the introduction of hourly offers.

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

In 2015, average energy market net revenues decreased by 23 percent for a new peaker (CT), 27 percent for a new combined cycle unit, 53 percent for a new coal plant and 38 percent for a new nuclear plant. The comparisons to 2014 reflect the very high net revenues in January 2014.

Despite lower net revenues, the market signals were still positive for new investment in gas-fired units, particularly in eastern PJM zones. But market signals continued to be negative for coal and nuclear units. In 2015, a new peaker (CT) would have received sufficient net revenue to cover levelized total costs in six of the 20 zones and more than 90 percent of levelized total costs in an additional six zones. In 2015, a new combined cycle unit would have received sufficient net revenue to cover levelized total costs in nine of the 20 zones and more than 90 percent of levelized total costs in an additional four zones.

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

But the market paradigm and the quasi-market paradigm are mutually exclusive. Once the decision is made that market outcomes must be fundamentally modified, it will be virtually impossible to return to markets. While there are entities in the PJM markets that continue to operate under the quasi-market paradigm, they have made a long term decision on a regulatory model and the PJM rules generally limit any associated, potential negative impacts on markets. That consistent approach to the regulatory model is very different from current

attempts to subsidize specific uneconomic market assets using various planning concepts as a rationale. The subsidy model is inconsistent with the PJM market design and inconsistent with the market paradigm and constitutes a significant threat to both.

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

These market design choices have substantial impacts. Capacity prices that were suppressed substantially below the level consistent with supply and demand fundamentals affected some participants' long term decisions. PJM has addressed the fundamental issues of the capacity market design in its Capacity Performance design, including price formation, product definition and performance incentives.

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

Load pays for the transmission system and contributes all congestion revenues. For that reason, FTRs and later ARRs were intended to return congestion revenues to load. The annual ARR allocation should be designed to return congestion revenues to load, without requiring contract path physical transmission rights that are difficult or impossible to define and enforce in LMP markets. The current ARR/FTR design does not serve as an efficient or effective way to ensure that load receives all the congestion revenues or has the ability to receive the auction revenues associated with all the potential congestion revenues.

In recent planning years, ARRs did not serve as an effective way to return congestion revenues to load. Total ARR and self scheduled FTR revenues offset only 42.4 percent of total congestion costs for the 2013 to 2014 planning period and only 63.8 percent of total congestion costs for the 2014 to 2015 planning period. In the first seven months of the 2015 to 2016 planning period, total ARR and self scheduled FTR revenues offset 85.8 percent of total congestion costs.

If the original PJM FTR design had simply been designed to return congestion revenues to load, many of the subsequent issues with the FTR design would have been avoided. Now is a good time to address the issues of the FTR design and to return the design to its original purpose. This would eliminate much of the complexity associated with ARRs and FTRs and eliminate unnecessary controversy about the appropriate recipients of congestion revenues.

On January 25, 2016, the U.S. Supreme Court voted 6-2 to reverse the decision of the lower court in the EPSA case. The Supreme Court's decision was about jurisdiction over demand side resources and not about the substance of Order 745. In resolving the uncertainty about jurisdiction, the decision creates an opportunity to rethink the ways in which demand side resources can most effectively participate in wholesale power markets based on market principles. The Commission has the clear authority to modify or reverse Order 745.

The long term appropriate end state for demand resources in the PJM markets should be comparable to the demand side of any market. Rather than demand response programs, with their complex and difficult to administer rules, customers would be able to avoid

capacity and energy charges by not using capacity and energy at their discretion. Customers should use energy as they wish and that usage will determine the amount of capacity and energy for which each customer pays. There is no need for counterfactual and inaccurate measurement and verification.

Under this approach, customers that wish to avoid capacity payments would reduce their load during expected high load hours. Capacity costs would be assigned to customers based on actual load on the system during these hours. Customers that wish to avoid high energy prices would reduce their load during high price hours. Customers would pay for what they actually use, as measured by meters, rather than relying on flawed measurement and verification methods.

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

The PJM markets and PJM market participants from all sectors face significant challenges. PJM and its market participants will need to continue to work constructively to address these challenges to ensure the continued effectiveness of PJM markets.

## PJM Market Summary Statistics

Table 1 shows selected summary statistics describing PJM markets.

### Table 1 PJM Market Summary Statistics, 2014 and 2015[1]

| | 2014 | 2015 | Percent Change |
|---|---|---|---|
| Load | 780,505 GWh | 776,083 GWh | (0.6%) |
| Generation | 807,986 GWh | 786,698 GWh | (2.6%) |
| Net Actual Interchange | (324) GWh | 15,368 GWh | 4,843% |
| Losses | 17,150 GWh | 16,241 GWh | (5.3%) |
| Regulation Requirement* | 664 MW | 641 MW | (3.5%) |
| RTO Primary Reserve Requirement | 2,063 MW | 2,175 MW | 5.4% |
| Total Billing | $50.03 Billion | $42.63 Billion | (14.8%) |
| **Peak** | **Jun 17, 2014 16:00** | **Jul 28, 2015 16:00** | |
| Peak Load | 141,673 MW | 143,697 MW | 1.4% |
| Load Factor | 0.63 | 0.62 | (2.0%) |
| **Installed Capacity** | **As of 12/31/2014** | **As of 12/31/2015** | |
| Installed Capacity | 184,400 MW | 177,683 MW | (3.6%) |

* This is an hourly average stated in effective MW.

## PJM Market Background

The PJM Interconnection, L.L.C. (PJM) operates a centrally dispatched, competitive wholesale electric power market that, as of December 31, 2015, had installed generating capacity of 177,683 megawatts (MW) and 957 members including market buyers, sellers and traders of electricity in a region including more than 61 million people in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia (Figure 1).[2] [3] [4]

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

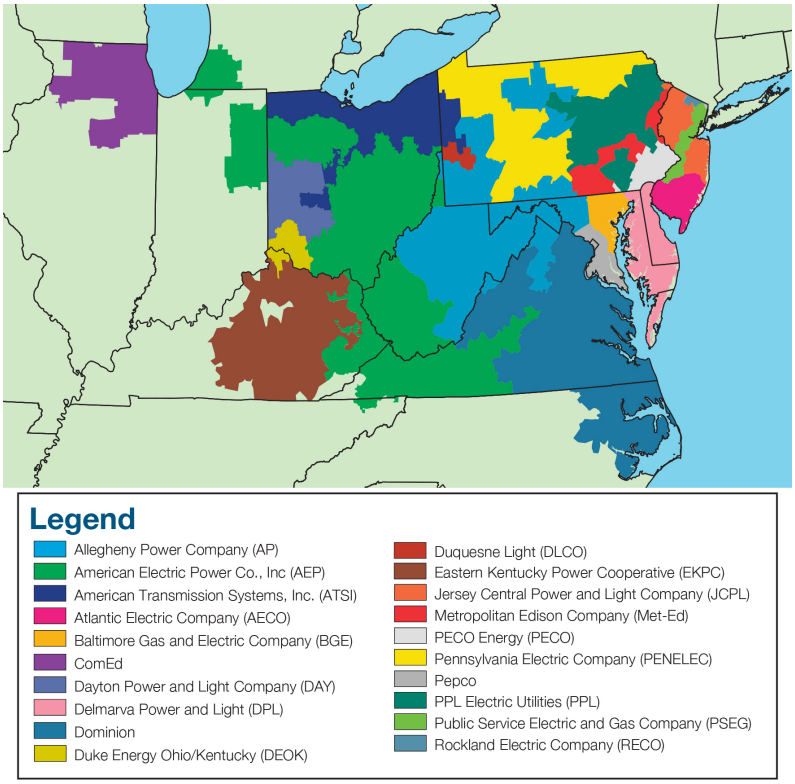
1 The load reported in this table is the accounting load plus net withdrawals at generator buses. The average hourly accounting load is reported in Section 3, "Energy Market."

2 See PJM's "Member List," which can be accessed at: <http://pjm.com/about-pjm/member-services/member-list.aspx>.

3 See PJM's "Who We Are," which can be accessed at: <http://pjm.com/about-pjm/who-we-are.aspx>.

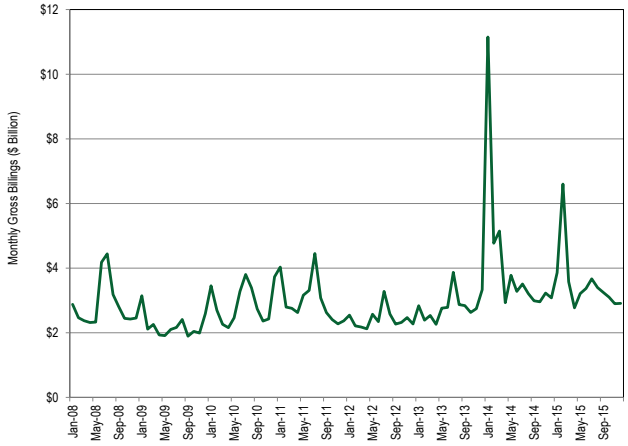
4 See the *2015 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography" for maps showing the PJM footprint and its evolution prior to 2015.

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




In 2015, PJM had total billings of $42.62 billion, down 15 percent from $50.04 billion in 2014 (Figure 2).[5]

### Figure 2 PJM reported monthly billings ($ Billion): 2008 through 2015




5 Monthly billing values are provided by PJM.

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 Financial Transmission Rights (FTRs) Markets.

PJM introduced energy pricing with cost-based offers and market-clearing nodal prices on April 1, 1998, and market-clearing nodal prices with market-based offers on April 1, 1999. PJM introduced the Daily Capacity Market on January 1, 1999, and the Monthly and Multimonthly Capacity Markets for the January through May 1999 period. PJM implemented FTRs on May 1, 1999. PJM implemented the Day-Ahead Energy Market and the Regulation Market on June 1, 2000. PJM modified the Regulation Market design and added a market in Synchronized Reserve on December 1, 2002. PJM introduced an Auction Revenue Rights (ARR) allocation process and an associated Annual FTR Auction effective June 1, 2003. PJM introduced the RPM Capacity Market effective June 1, 2007. PJM implemented the DASR Market on June 1, 2008.[6] [7] PJM introduced the Capacity Performance capacity market design effective on August 10, 2015, with the Base Residual Auction for 2018/2019.

## Conclusions

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

6 See also the *2015 State of the Market Report for PJM*, Volume II, Appendix B, "PJM Market Milestones."

7 Analysis of 2015 market results requires comparison to prior years. During calendar years 2004 and 2005, PJM conducted the phased integration of five control zones: ComEd, American Electric Power (AEP), The Dayton Power & Light Company (DAY), Duquesne Light Company (DLCO) and Dominion. In June 2011, the American Transmission Systems, Inc. (ATSI) Control Zone joined PJM. In January 2012, the Duke Energy Ohio/Kentucky Control Zone joined PJM. In June 2013, the Eastern Kentucky Power Cooperative (EKPC) joined PJM. By convention, control zones bear the name of a large utility service provider working within their boundaries. The nomenclature applies to the geographic area, not to any single company. For additional information on the integrations, their timing and their impact on the footprint of the PJM service territory prior to 2015, see *2014 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography."

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

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

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

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

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

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

The MMU concludes for 2015:

**Table 2 The Energy Market results were competitive**

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

- The aggregate market structure was evaluated as competitive because the calculations for hourly HHI (Herfindahl-Hirschman Index) indicate that by the FERC standards, the PJM Energy Market in 2015 was moderately concentrated. Average HHI was 1096 with a minimum of 879 and a maximum of 1468 in 2015. The fact that the average HHI was in the moderately concentrated range does not mean that the aggregate market was competitive in all hours. The PJM Energy Market intermediate and peaking segments of supply were highly concentrated.
- The local market structure was evaluated as not competitive due to the highly concentrated ownership of supply in local markets created by transmission constraints. The results of the three pivotal supplier (TPS) test, used to test local market structure, indicate the existence of market power in local markets created by transmission constraints. The local market performance is competitive as a result of the application of the TPS test. While transmission constraints create the potential for the exercise of local market power, PJM's application of the three pivotal supplier test identified local market power and resulted in offer capping to force competitive offers, correcting for structural issues created by local transmission constraints. There are, however, identified issues with the application of market power mitigation to resources whose owners fail the TPS test that need to be addressed.
- Participant behavior was evaluated as competitive because the analysis of markup shows that marginal units generally make offers at, or close to, their marginal costs in both Day-Ahead and Real-Time Energy Markets, although the behavior of some participants both routinely and during periods of high demand is consistent with economic withholding.

- Market performance was evaluated as competitive because market results in the energy market reflect the outcome of a competitive market, as PJM prices are set, on average, by marginal units operating at, or close to, their marginal costs in both Day-Ahead and Real-Time Energy Markets, although high markups during periods of high demand did affect prices.
- Market design was evaluated as effective because the analysis shows that the PJM energy market resulted in competitive market outcomes. In general, PJM's energy market design provides incentives for competitive behavior and results in competitive outcomes. In local markets, where market power is an issue, the market design identifies market power and causes the market to provide competitive market outcomes. The role of UTCs in the Day-Ahead Energy Market continues to cause concerns.

PJM markets are designed to promote competitive outcomes derived from the interaction of supply and demand in each of the PJM markets. Market design itself is the primary means of achieving and promoting competitive outcomes in PJM markets. One of the MMU's primary goals is to identify actual or potential market design flaws.[8] The approach to market power mitigation in PJM has focused on market designs that promote competition (a structural basis for competitive outcomes) and on limiting market power mitigation to instances where the market structure is not competitive and thus where market design alone cannot mitigate market power. In the PJM energy market, this occurs primarily in the case of local market power. When a transmission constraint creates the potential for local market power, PJM applies a structural test to determine if the local market is competitive, applies a behavioral test to determine if generator offers exceed competitive levels and applies a market performance test to determine if such generator offers would affect the market price.[9] There are, however, identified issues with the application of market power mitigation to resources whose owners fail the TPS test that can result in the exercise of local market power. These issues need to be addressed. There are issues related to the definition of gas costs includable in energy offers that need to be addressed. There are currently no market power mitigation rules in place that limit the ability to exercise market power when aggregate market conditions are tight. If market-based offer caps are raised, or if generators are allowed to modify offers hourly, market design must reflect appropriate incentives for competitive behavior and aggregate market power mitigation rules need to be developed.

**Table 3 The Capacity Market results were competitive**

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

- The aggregate market structure was evaluated as not competitive. For almost all auctions held from 2007 to the present, the PJM region failed the three pivotal supplier test (TPS), which is conducted at the time of the auction.[10]
- The local market structure was evaluated as not competitive. For almost every auction held, all LDAs have failed the TPS test, which is conducted at the time of the auction.[11]
- Participant behavior was evaluated as competitive. Market power mitigation measures were applied when the Capacity Market Seller failed the market power test for the auction, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, would increase the market clearing price. Market power mitigation rules were also applied when the Capacity Market Seller submitted a sell offer for a new resource or uprate that was below the Minimum Offer Price Rule (MOPR) threshold.
- Market performance was evaluated as competitive. Although structural market power exists in the Capacity Market, a competitive outcome resulted from the application of market power mitigation rules.
- Market design was evaluated as mixed because while there are many positive features of the Reliability Pricing Model (RPM) design and the

8 PJM. OATT Attachment M (PJM Market Monitoring Plan).

9 The market performance test means that offer capping is not applied if the offer does not exceed the competitive level and therefore market power would not affect market performance.

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

11 In the 2012/2013 RPM Base Residual Auction, six participants included in the incremental supply of EMAAC passed the TPS test. In the 2014/2015 RPM Base Residual Auction, seven participants in the incremental supply in MAAC passed the TPS test.

Capacity Performance modifications to RPM, there are several features of the RPM design which still threaten competitive outcomes. These include the definition of DR which permits inferior products to substitute for capacity, the replacement capacity issue, the definition of unit offer parameters and the inclusion of imports which are not substitutes for internal capacity resources.

### Table 4 The Regulation Market results were competitive

| Market Element | Evaluation | Market Design |
|---|---|---|
| Market Structure | Not Competitive | |
| Participant Behavior | Competitive | |
| **Market Performance** | **Competitive** | **Flawed** |

- The Regulation Market structure was evaluated as not competitive for 2015 because the Regulation Market failed the three pivotal supplier (TPS) test in 97.8 percent of the hours in 2015.
- Participant behavior in the Regulation Market was evaluated as competitive for 2015 because market power mitigation requires competitive offers when the three pivotal supplier test is failed and there was no evidence of generation owners engaging in anti-competitive behavior.
- Market performance was evaluated as competitive, despite significant issues with the market design.
- Market design was evaluated as flawed. While the design of the Regulation Market was significantly improved with changes introduced October 1, 2012, a number of issues remain. The market design has failed to correctly incorporate a consistent implementation of the marginal benefit factor in optimization, pricing and settlement. The market results continue to include the incorrect definition of opportunity cost.

### Table 5 The Tier 2 Synchronized Reserve Markets results were competitive

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

- The Tier 2 Synchronized Reserve Market structure was evaluated as not competitive because of high levels of supplier concentration.
- Participant behavior was evaluated as competitive because the market rules require competitive, cost based offers, although there is concern about failure to comply with the must offer requirement.
- Market performance was evaluated as competitive because the interaction of participant behavior with the market design results in competitive prices.
- Market design was evaluated as mixed. Market power mitigation rules result in competitive outcomes despite high levels of supplier concentration. However, tier 1 reserves are inappropriately compensated when the non-synchronized reserve market clears with a nonzero price.

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

| Market Element | Evaluation | Market Design |
|---|---|---|
| Market Structure | Not Competitive | |
| Participant Behavior | Mixed | |
| **Market Performance** | **Competitive** | **Mixed** |

- The Day-Ahead Scheduling Reserve Market structure was evaluated as not competitive because market participants failed the three pivotal supplier test in 6.4 percent of all cleared hours in 2015.
- Participant behavior was evaluated as mixed because while most offers were equal to marginal costs, a significant proportion of offers reflected economic withholding.
- Market performance was evaluated as competitive because there were adequate offers in every hour to satisfy the requirement and the clearing prices reflected those offers, although there is concern about offers above the competitive level affecting prices.
- Market design was evaluated as mixed because while the market is functioning effectively to provide DASR, the three pivotal supplier test and appropriate market power mitigation should be added to the market to ensure that market power cannot be exercised at times of system stress.

### Table 7 The FTR Auction Markets results were competitive

| Market Element | Evaluation | Market Design |
|---|---|---|
| Market Structure | Competitive | |
| Participant Behavior | Competitive | |
| **Market Performance** | **Competitive** | **Flawed** |

- Market structure was evaluated as competitive because the FTR auction is voluntary and the

ownership positions resulted from the distribution of ARRs and voluntary participation.

- Participant behavior was evaluated as competitive because there was no evidence of anti-competitive behavior.
- Market performance was evaluated as competitive because it reflected the interaction between participant demand behavior and FTR supply, limited by PJM's analysis of system feasibility.
- Market design was evaluated as flawed because there are significant flaws with the basic ARR/FTR design which need to be addressed. The market design is not an efficient way to ensure that congestion revenues are returned to load.

## Role of MMU

The FERC assigns three core functions to MMUs: reporting, monitoring and market design.[12] These functions are interrelated and overlap. The PJM Market Monitoring Plan establishes these functions, providing that the MMU is responsible for monitoring: compliance with the PJM Market Rules; actual or potential design flaws in the PJM Market Rules; structural problems in the PJM Markets that may inhibit a robust and competitive market; the actual or potential exercise of market power or violation of the market rules by a Market Participant; PJM's implementation of the PJM Market Rules or operation of the PJM Markets; and such matters as are necessary to prepare reports.[13]

### Reporting

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

### Monitoring

To perform its monitoring function, the MMU screens and monitors the conduct of Market Participants under the MMU's broad purview to monitor, investigate, evaluate and report on the PJM Markets.[14] The MMU has direct, confidential access to the FERC.[15] The MMU may also refer matters to the attention of state commissions.[16]

The MMU monitors market behavior for violations of FERC Market Rules.[17] The MMU will investigate and refer "Market Violations," which refers to any of "a tariff violation, violation of a Commission-approved order, rule or regulation, market manipulation, or inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies..."[18] [19] [20] The MMU also monitors PJM for compliance with the rules, in addition to market participants.[21]

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

12 18 CFR § 35.28(g)(3)(ii); see also *Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, FERC Stats. & Regs. ¶31,281 (2008) ("Order No. 719"), *order on reh'g*, Order No. 719-A, FERC Stats. & Regs. ¶31,292 (2009), *reh'g denied*, Order No. 719-B, 129 FERC ¶ 61,252 (2009).

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

14 OATT Attachment M § IV.

15 OATT Attachment M § IV.K.3.

16 OATT Attachment M § IV.H.

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

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

19 OATT Attachment M § II(h-1).

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

21 OATT Attachment M § IV.C.

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).[22] 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.[23]

The MMU also reviews operational parameter limits included with unit offers, evaluates compliance with the requirement to offer into the energy and capacity markets, evaluates the economic basis for unit retirement requests and evaluates and compares offers in the Day-Ahead and Real-Time Energy Markets.[24] [25] [26] [27]

The MMU reviews offers and inputs in order to evaluate whether those offers raise market power concerns.[28] Market participants, not the MMU, determine and take responsibility for offers that they submit and the market conduct that those offers represent.[29] If the MMU has a concern about an offer, the MMU may raise that concern with the FERC or other regulatory authorities. The FERC and other regulators have enforcement and regulatory authority that they may exercise with respect to offers submitted by market participants. PJM also reviews offers, but it does so in order to determine whether offers comply with the PJM tariff and manuals.[30] PJM, in its role as the market operator, may reject an offer that fails to comply with the market rules. The respective reviews performed by the MMU and PJM are separate and non-sequential.

The PJM Markets monitored by the MMU include market related procurement processes conducted by PJM, such as for Black Start resources included in the PJM system restoration plan.[31] [32] With the introduction of competitive transmission development policy in Order No. 1000, a competitive procurement process for including projects in PJM Regional Transmission Expansion Plan is now in place.[33]

## 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.[34] The MMU initiates and proposes changes to the design of such markets or the PJM Market Rules in stakeholder or regulatory proceedings.[35] 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.[36] 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.[37] The MMU may provide in its annual, quarterly and other reports "recommendations regarding any matter within its purview."[38]

## New 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,"[39] 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.

In this *2015 State of the Market Report for PJM*, the MMU includes 27 recommendations that were new in 2015, ten of which are evaluated as high priority. Seventeen of the 27 new recommendations for 2015 are reported for the first time in this annual state of the market report. For a complete list of all MMU recommendations, see Section 2, Recommendations.

22 See OATT Attachment M–Appendix § II.A.
23 OATT Attachment M–Appendix § II.E.
24 OATT Attachment M–Appendix § II.B.
25 OATT Attachment M–Appendix § II.C.
26 OATT Attachment M–Appendix § IV.
27 OATT Attachment M–Appendix § VII.
28 OATT Attachment M § IV.
29 OATT § 12A.
30 OATT § 12A.
31 See OATT Attachment M–Appendix § II(p).
32 See OATT Attachment M–Appendix § III.
33 OA Schedule 6 § 1.5.
34 OATT Attachment M § IV.D.
35 *Id.*
36 *Id.*
37 *Id.*
38 OATT Attachment M § VI.A.
39 18 CFR § 35.28(g)(3)(ii)(A); see also OATT Attachment M § IV.D.

## New Recommendation from Section 3, Energy Market

- The MMU recommends, in order to ensure effective market power mitigation when the TPS test is failed, that markup be constant across price and cost offers, that there be at least one cost-based offer using the same fuel as the available price-based offer. (Priority: High. New recommendation. Status: Not adopted.)
- The MMU recommends that in order to ensure effective market power mitigation when the TPS test is failed, the operating parameters in the cost-based offer and the price-based parameter limited schedule (PLS) offer be at least as flexible as the operating parameters in the available non-PLS price-based offer, and that the price-MW pairs in the price based PLS offer be exactly equal to the price based non PLS offer. (Priority: High. New recommendation. Status: Not adopted.)
- The MMU recommends that under the Capacity Performance construct, PJM recognize the difference between operational parameters that indicate to PJM dispatchers what a unit is capable of during the operating day and the parameters that are used for capacity performance assessment as well as uplift payments. The parameters which determine non-performance charges and the amount of uplift payments to those generators should reflect the flexibility goals of the capacity performance construct. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that capacity performance resources and base capacity resources (during the June through September period) be held to the OEM operating parameters of the capacity market CONE reference resource for performance assessment and energy uplift payments. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that PJM remove non-specific fuel types such as "other" or "co-fire other" from the list of fuel types available for market participants to identify the fuel type associated with their price and cost schedules. (Priority: Medium. First reported Q2, 2015. Status: Not adopted.)
- The MMU recommends that PJM explicitly state its policy on the use of transmission penalty factors including the level of the penalty factors, the triggers for the use of the penalty factors, the appropriate line ratings to trigger the use of penalty factors, and when the transmission penalty factors will be used to set the shadow price. (Priority: Medium. New recommendation Status: Not adopted.)

## New Recommendations from Section 4, Energy Uplift

- The MMU recommends that PJM not use price setting logic to artificially override the nodal prices that are based on fundamental LMP logic in order to reduce uplift. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that units scheduled in the Day-Ahead Energy Market and not committed in real time should be compensated for LOC based on their real-time desired and achievable output, not their scheduled day-ahead output. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that only flexible fast start units (startup plus notification times of 30 minutes or less) and short minimum run times (one hour or less) be eligible by default for the LOC compensation to units scheduled in the Day-Ahead Energy Market and not committed in real time. Other units should be eligible for LOC compensation only if PJM explicitly cancels their day-ahead commitment. (Priority: Medium. First reported 2015. Status: Not adopted.)

## New Recommendations from Section 6, Demand Response

- The MMU recommends that PJM require nodal dispatch of demand resources with no advance notice required or, if nodal location is not required, subzonal dispatch of demand resources with no advance notice required. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM eliminate the measurement of compliance across zones within a compliance aggregation area (CAA). The multiple zone approach is less locational than the zonal and subzonal approach and creates larger mismatches between the locational need for the resources and

the actual response. (Priority: High. First reported 2015. Status: Not adopted.)

- The MMU recommends that the Net Benefits Test be eliminated and that demand response resources be paid LMP less any generation component of the applicable retail rate. (Priority: Low. New recommendation. Status: Not adopted. )
- The MMU recommends that the tariff rules for demand response clarify that a resource and its CSP, if any, must notify PJM of material changes affecting the capability of the resource to perform as registered and to terminate registrations that are no longer capable of responding to PJM dispatch directives because load has been reduced or eliminated, such as in the case of bankrupt and/or out of service facilities. (Priority: Medium. First reported Q2, 2015. Status: Not adopted.)

## New Recommendations from Section 9, Interchange Transactions

- The MMU recommends that PJMSettlement Inc. immediately request a credit evaluation from all companies that engaged in up to congestion transactions between September 8, 2014, and December 31, 2015. If PJM has the authority, PJM should ensure that the potential exposure to uplift for that period be included as a contingency in the companies' calculations for credit levels and/or collateral requirements. If PJM does not have the authority to take such steps, PJM should request guidance from FERC. (Priority: High. New recommendation. Status: Not adopted.)
- The MMU recommends that the emergency interchange cap be replaced with a market based solution. (Priority: Low. New recommendation. Status: Not adopted.)

## New Recommendations from Section 10, Ancillary Services

- The MMU recommends that a reason code be attached to every hour in which PJM market operations adds additional DASR MW. (Priority: Medium. First reported Q2, 2015. Status: not adopted.)

## New Recommendations from Section 12, Planning

- The MMU recommends that rules be implemented to require that project cost caps on new transmission projects be part of the evaluation of competing projects. (Priority: Low. New recommendation. Status: Not adopted.)
- The MMU recommends that PJM enhance the transparency and queue management process for merchant transmission investment. Issues related to data access and complete explanations of cost impacts should be addressed. The goal should be to remove barriers to competition from merchant transmission. (Priority: Medium. First reported Q2, 2015. Status: Not adopted.)
- The MMU recommends consideration of changing the minimum distribution factor in the allocation from .01 to .00 and adding a threshold minimum impact on the load on the line. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that PJM draft a clear definition of the congestion analysis required for transmission outage requests to include in Manual 3 after appropriate review. (Priority: Low. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM modify the rules to reduce or eliminate the approval of late outage requests submitted or rescheduled after the FTR auction bidding opening date. (Priority: Low. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM not permit transmission owners to divide long duration outages into smaller segments to avoid complying with the requirements for long duration outages. (Priority: Low. New recommendation. Status: Not adopted.)

## New Recommendations from Section 13, Financial Transmission Rights

- The MMU recommends that the ARR/FTR design be modified to ensure that all congestion revenues are returned to load. (Priority: High. New recommendation. Status: Not adopted.)
- The MMU recommends that all FTR auction revenue be distributed to ARR holders. (Priority: High. New recommendation. Status: Not adopted.)

- The MMU recommends that historical generation to load paths be eliminated as a basis for allocating ARRs. (Priority: High. New recommendation. Status: Not adopted.)
- The MMU recommends that counter flow FTRs be eliminated. (Priority: High. New recommendation. Status: Not adopted.)
- The MMU recommends that FTR auction revenues not be used to buy counter flow FTRs with the purpose of improving FTR payout ratios.[40] (Priority: High. New recommendation. Status: Not adopted.)

## History of MMU Recommendations

The MMU began making recommendations to PJM in the 1999 State of the Market Report. Since that time, the MMU has made approximately 200 recommendations in the State of the Market Reports. In 2014, the MMU began including a priority and status with each recommendation. In this *2015 State of the Market Report for PJM*, the MMU has reviewed all past recommendations, assigned priority and determined their current status.

MMU recommendations are given the status of "Adopted," "Partially Adopted," or "Not Adopted." Some early recommendations are no longer reported and may have evolved into newer recommendations. These are categorized as "Replaced by Newer Recommendation."

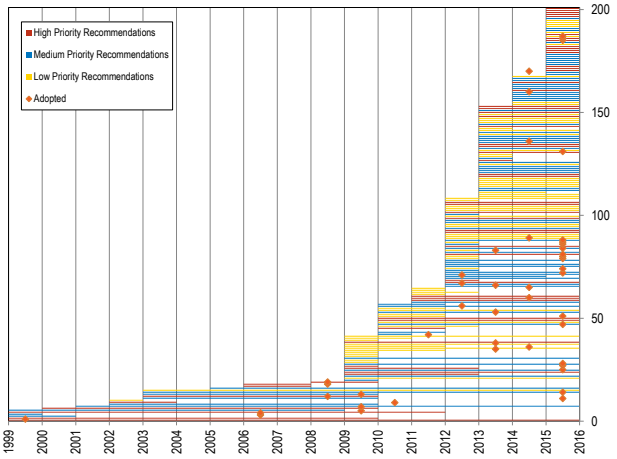
Table 2-1 shows the status of all recommendations reported by the MMU from 1999 through 2015. Over that time, 24 percent of all MMU recommendations have been adopted and 60 percent are not adopted. Of the 56 high priority recommendations, 20 (36 percent) have been adopted.

### Table 8 Status of MMU reported recommendations: 1999 through 2015

| Status | Priority High | Priority Medium | Priority Low | Total | Percent of Total |
|---|---|---|---|---|---|
| Adopted | 20 | 13 | 16 | 49 | 24.4% |
| Partially Adopted | 6 | 10 | 8 | 24 | 11.9% |
| Not Adopted | 20 | 39 | 44 | 103 | 51.2% |
| Not Adopted (Pending before FERC) | 3 | 1 | 0 | 4 | 2.0% |
| Not Adopted (Stakeholder Process) | 6 | 7 | 1 | 14 | 7.0% |
| Not Adopted (Total) | 29 | 47 | 45 | 121 | 60.2% |
| Replaced by Newer Recommendation | 1 | 5 | 1 | 7 | 3.5% |
| Total | 56 | 75 | 70 | 201 | 100% |

As shown in Figure 2-1, the MMU continues to make recommendations, and progress continues on recommendation adoption. In the figure, each line represents a recommendation, starting on the date it was first reported, and ending on the most recent instance of the recommendation. The orange markers indicate the date of adoption of a recommendation.

### Figure 3 History of recommendation creation and closure: 1999 through 2015




## 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 8 provides the average price and total revenues paid, by component, for 2014 and 2015.

40 See PJM. "Manual 6: Financial Transmission Rights" Revision 16 (June 1, 2014), p. 56.

Table 8 shows that Energy, Capacity and Transmission Service Charges are the three largest components of the total price per MWh of wholesale power, comprising 95.6 percent of the total price per MWh in 2015.

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

## Components of Total Price

- The Energy component is the real time load weighted average PJM locational marginal price (LMP).
- The Capacity component is the average price per MWh of Reliability Pricing Model (RPM) payments.
- The Transmission Service Charges component is the average price per M Wh of network integration charges, and firm and non firm point to point transmission service.[41]
- The Energy Uplift (Operating Reserves) component is the average price per MWh of day-ahead and balancing operating reserves and synchronous condensing charges.[42]
- The Reactive component is the average cost per MWh of reactive supply and voltage control from generation and other sources.[43]
- The Regulation component is the average cost per MWh of regulation procured through the Regulation Market.[44]
- 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 (AC2) 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.[45]
- The Capacity (FRR) component is the average cost per MWh under the Fixed Resource Requirement (FRR) Alternative for an eligible LSE to satisfy its Unforced Capacity obligation.[46]
- The Emergency Load Response component is the average cost per MWh of the PJM Emergency Load Response Program.[47]
- 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.[48]
- 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.[49]
- The Synchronized Reserve component is the average cost per MWh of synchronized reserve procured through the Synchronized Reserve Market.[50]
- The Black Start component is the average cost per MWh of black start service.[51]
- The RTO Startup and Expansion component is the average cost per MWh of charges to recover AEP, ComEd and DAY's integration expenses.[52]
- The NERC/RFC component is the average cost per MWh of NERC and RFC charges, plus any reconciliation charges.[53]
- The Economic Load Response component is the average cost per MWh of day ahead and real time economic load response program charges to LSEs.[54]
- The Transmission Facility Charges component is the average cost per MWh of Ramapo Phase Angle Regulators charges allocated to PJM Mid-Atlantic transmission owners.[55]
- The Non-Synchronized Reserve component is the average cost per MWh of non-synchronized reserve procured through the Non-Synchronized Reserve Market.[56]

41 OATT §§ 13.7, 14.5, 27A & 34.
42 OA Schedules 1 §§ 3.2.3 & 3.3.3.
43 OATT Schedule 2 and OA Schedule 1 § 3.2.3B. The line item in Table 8 includes all reactive services charges.
44 OA Schedules 1 §§ 3.2.2, 3.2.2A, 3.3.2, & 3.3.2A; OATT Schedule 3.
45 OATT Schedule 12.
46 Reliability Assurance Agreement Schedule 8.1.
47 OATT PJM Emergency Load Response Program.
48 OA Schedules 1 §§ 3.2.3A.01 & OATT Schedule 6.
49 OATT Schedule 1A.
50 OA Schedule 1 § 3.2.3A.01; PJM OATT Schedule 6.
51 OATT Schedule 6A. The line item in Table 8 includes all Energy Uplift (Operating Reserves) charges for Black Start.
52 OATT Attachments H-13, H-14 and H-15 and Schedule 13.
53 OATT Schedule 10-NERC and OATT Schedule 10-RFC.
54 OA Schedule 1 § 3.6.
55 OA Schedule 1 § 5.3b.
56 OA Schedule 1 § 3.2.3A.001.

- The Emergency Energy component is the average cost per MWh of emergency energy.[57]

**Table 9 Total price per MWh by category: 2014 and 2015**

| Category | 2014 $/MWh | 2014 Percent of Total | 2015 $/MWh | 2015 Percent of Total | 2014 to 2015 Percent Change Totals |
|---|---|---|---|---|---|
| Load Weighted Energy | $53.14 | 74.2% | $36.16 | 63.6% | (31.9%) |
| Capacity | $9.01 | 12.6% | $11.12 | 19.6% | 23.5% |
| Transmission Service Charges | $5.95 | 8.3% | $7.08 | 12.5% | 19.0% |
| Transmission Enhancement Cost Recovery | $0.42 | 0.6% | $0.51 | 0.9% | 19.2% |
| PJM Administrative Fees | $0.44 | 0.6% | $0.44 | 0.8% | 0.1% |
| Energy Uplift (Operating Reserves) | $1.18 | 1.6% | $0.38 | 0.7% | (67.7%) |
| Reactive | $0.40 | 0.6% | $0.37 | 0.7% | (6.0%) |
| Regulation | $0.33 | 0.5% | $0.23 | 0.4% | (28.8%) |
| Capacity (FRR) | $0.20 | 0.3% | $0.13 | 0.2% | (38.7%) |
| Synchronized Reserves | $0.21 | 0.3% | $0.12 | 0.2% | (41.4%) |
| Day Ahead Scheduling Reserve (DASR) | $0.05 | 0.1% | $0.10 | 0.2% | 115.5% |
| Transmission Owner (Schedule 1A) | $0.09 | 0.1% | $0.09 | 0.2% | 1.2% |
| Black Start | $0.08 | 0.1% | $0.06 | 0.1% | (15.5%) |
| NERC/RFC | $0.02 | 0.0% | $0.03 | 0.0% | 19.5% |
| Non-Synchronized Reserves | $0.02 | 0.0% | $0.02 | 0.0% | 2.1% |
| Load Response | $0.02 | 0.0% | $0.02 | 0.0% | (15.2%) |
| RTO Startup and Expansion | $0.01 | 0.0% | $0.01 | 0.0% | (49.0%) |
| Transmission Facility Charges | $0.00 | 0.0% | $0.00 | 0.0% | 134.6% |
| Emergency Load Response | $0.06 | 0.1% | $0.00 | 0.0% | (98.9%) |
| Emergency Energy | $0.01 | 0.0% | $0.00 | 0.0% | (100.0%) |
| Total | $71.62 | 100.0% | $56.86 | 100.0% | (20.6%) |

# Section Overviews

## Overview: Section 3, "Energy Market"

### Market Structure

- **Supply.** Supply includes physical generation and imports and virtual transactions. Average offered real-time generation increased by 4,490 MW, or 2.8 percent, in the summer months of 2015 from an average maximum of 160,190 in the summer of 2014 to 164,680 MW in the summer of 2015 of 160,190 MW to 164,680 MW. In 2015, 3,041.2 MW of new capacity were added to PJM. This new generation was more than offset by the deactivation of 9,897.2 MW.

  PJM average real-time generation in 2015 decreased by 2.5 percent from 2014, from 90,894 MW to 88,628 MW.

  PJM average day-ahead supply in 2015, including INCs and up to congestion transactions, decreased by 21.7 percent from 2014, from 146,672 MW to 114,889 MW, primarily as a result of decreases in UTC volumes.

- **Market Concentration.** The PJM energy market was moderately concentrated overall with moderate concentration in the baseload segment, but high concentration in the intermediate and peaking segments.

- **Generation Fuel Mix.** During 2015, coal units provided 36.6 percent, nuclear units 35.5 percent and gas units 23.4 percent of total generation. Compared to 2014, generation from coal units decreased 17.8 percent, generation from gas units increased 27.7 percent and generation from nuclear units increased 0.5 percent.

- **Marginal Resources.** In the PJM Real-Time Energy Market, in 2015, coal units were 51.74 percent of marginal resources and natural gas units were 35.52 percent of marginal resources. In 2014, coal units were 52.90 percent and natural gas units were 35.81 percent of the marginal resources.

  In the PJM Day-Ahead Energy Market, in 2015, up to congestion transactions were 76.1 percent of marginal resources, INCs were 5.1 percent of marginal resources, DECs were 8.9 percent of marginal resources, and generation resources were 9.6 percent of marginal resources. In 2014, up to congestion transactions were 91.0 percent of marginal resources, INCs were 2.3 percent of marginal resources, DECs were 3.3 percent of marginal resources, and generation resources were 3.3 percent of marginal resources.

- **Demand.** Demand includes physical load and exports and virtual transactions. The PJM system peak load during 2015 was 143,697 MW in the HE 1700 on July 28, 2015, which was 2,023 MW, or 1.4 percent, higher than the PJM peak load for 2014, which was 141,673 MW in the HE 1700 on June 17, 2014.

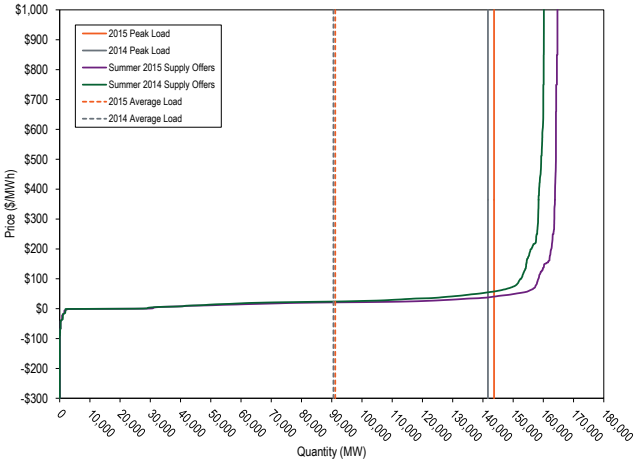
  PJM average real-time load in 2015 decreased by 0.6 percent from 2014, from 89,099 MW to 88,594 MW. PJM average day-ahead demand in 2015, including DECs and up to congestion transactions,

57 OA Schedule 1 §3.2.6.

decreased by 21.5 percent from 2014, from 142,644 MW to 111,644 MW.

- **Supply and Demand: Scarcity.** There were no shortage pricing events in 2015.

### Figure 4 Average PJM aggregate real-time generation supply curves by offer price: Summer of 2014 and 2015




## Market Behavior

- **Offer Capping for Local Market Power.** PJM offer caps units when the local market structure is noncompetitive. Offer capping is an effective means of addressing local market power. Offer capping levels have historically been low in PJM. In the Day-Ahead Energy Market, for units committed to provide energy for local constraint relief, offer-capped unit hours remained at 0.2 percent in 2014 and 2015. In the Real-Time Energy Market, for units committed to provide energy for local constraint relief, offer-capped unit hours decreased from 0.5 percent in 2014 to 0.4 percent in 2015.

  In 2015, 15 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 identify 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. There are, however, identified issues with the application of market power mitigation to resources whose owners fail the TPS test that can result in the exercise of local market power. These issues need to be addressed.

### Table 10 Offer-capping statistics for energy and reliability: 2011 through 2015

| | Real Time | | Day Ahead | |
|---|---|---|---|---|
| Year | Unit Hours Capped | MW Capped | Unit Hours Capped | MW Capped |
| 2011 | 0.7% | 0.2% | 0.0% | 0.0% |
| 2012 | 1.7% | 1.0% | 0.9% | 0.5% |
| 2013 | 2.9% | 2.4% | 3.2% | 2.1% |
| 2014 | 0.8% | 0.5% | 0.6% | 0.4% |
| 2015 | 0.7% | 0.8% | 0.6% | 0.7% |

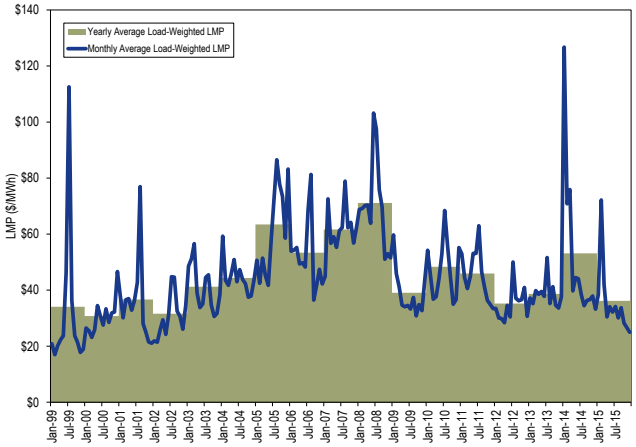
- **Offer Capping for Reliability.** PJM also offer caps units that are committed for reliability reasons, specifically for black start service and reactive service. In the Day-Ahead Energy Market, for units committed for reliability reasons, offer-capped unit hours remained at 0.4 percent in 2014 and 2015. In the Real-Time Energy Market, for units committed for reliability reasons, offer-capped unit hours increased from 0.3 percent in 2014 to 0.4 percent in 2015.
- **Markup Index.** The markup index is a summary measure of participant offer behavior for individual marginal units. In the PJM Real-Time Energy Market, when using unadjusted cost offers, in 2015, 85.9 percent of marginal units had average dollar markups less than zero and had an average markup index less than zero. Using adjusted cost offers, in 2015, 47.1 percent of marginal units had average dollar markups less than zero and average markup index less than or equal to zero. Some marginal units did have substantial markups. Using unadjusted cost offers, 0.17 percent of offers had offer prices greater than $400 per MWh with average dollar markup of $56.87 per MWh.

  In the PJM Day-Ahead Energy Market, when using unadjusted cost offers, in 2015, 3.2 percent of marginal generating units had an average markup index less than or equal to zero. Using adjusted cost offers, in the 2015, 3.2 percent of marginal units had an average markup index less than or equal to zero.
- **Frequently Mitigated Units (FMU) and Associated Units (AU).** A new FMU rule became effective November 1, 2014, limiting the availability of FMU adders to units with net revenues less than unit going forward costs. There were no units eligible for an FMU or AU adder in 2015.

- **Virtual Offers and Bids.** Any market participant in the PJM Day-Ahead Energy Market can use increment offers, decrement bids, up to congestion transactions, import transactions and export transactions as financial instruments that do not require physical generation or load. The reduction in up to congestion transactions (UTC) continued, following a FERC order setting September 8, 2014, as the effective date for any uplift charges subsequently assigned to UTCs but there was an increase in up to congestion volume in December 2015, coincident with the expiration of the fifteen month resettlement period for the proceeding related to uplift charges for UTC transactions.[58] [59]
- **Generator Offers.** Generator offers are categorized as dispatchable and self scheduled. Units which are available for economic dispatch are dispatchable. Units which are self scheduled to generate fixed output are categorized as self scheduled. Units which are self scheduled at their economic minimum and are available for economic dispatch up to their economic maximum are categorized as self scheduled and dispatchable. Of all generator offers in 2015, 56.1 percent were offered as available for economic dispatch, 23.8 percent were offered as self scheduled, and 20.1 percent were offered as self scheduled and dispatchable.

## Market Performance

**Figure 5 PJM real-time, monthly and annual, load-weighted, average LMP: 1999 through 2015**




- **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 changes in supply and demand, generation fuel mix, the cost of fuel, emission related expenses, markup and local price differences caused by congestion. PJM also may administratively set prices with the creation of a closed loop interface related to demand side resources or reactive power or the application of price setting logic.

  PJM Real-Time Energy Market prices decreased in 2015 compared to 2014. The load-weighted average real-time LMP was 31.9 percent lower in 2015 than in 2014, $36.16 per MWh versus $53.14 per MWh.

  PJM Day-Ahead Energy Market prices decreased in 2015 compared to 2014. The load-weighted average day-ahead LMP was 31.5 percent lower in 2015 than in 2014, $36.73 per MWh versus $53.62 per MWh.
- **Components of LMP.** In the PJM Real-Time Energy Market, for 2015, 43.2 percent of the load-weighted LMP was the result of coal costs, 27.2 percent was the result of gas costs and 2.32 percent was the result of the cost of emission allowances.

  In the PJM Day-Ahead Energy Market for 2015, 29.6 percent of the load-weighted LMP was the result of the cost of coal, 22.5 percent was the result of DECs, 14.3 percent was the result of the cost of gas, 11.6 percent was the result of INCs, and 4.3 percent was the result of up to congestion transactions.
- **Markup.** The markup conduct of individual owners and units has an identifiable impact on market prices. Markup is a key indicator of the competitiveness of the Energy Market.

  In the PJM Real-Time Energy Market in 2015, the adjusted markup component of LMP was $1.75 per MWh or 4.8 percent of the PJM real-time, load-weighted average LMP. The month of February had the highest adjusted markup component, $6.44 per MWh, or 12.65 percent of the real-time load-weighted average LMP.

  In the PJM Day-Ahead Energy Market, marginal INCs, DECs and UTCs have zero markups. In 2015, the adjusted markup component of LMP resulting

58 148 FERC ¶ 61,144 (2014).
59 16 U.S.C. § 824e.

from generation resources was $0.78 per MWh or 2.1 percent of the PJM day-ahead load-weighted average LMP. The month of February had the highest adjusted markup component, $2.81 per MWh or 3.6 percent of the day-ahead load-weighted average LMP. In 2015, the highest hourly adjusted markup was $710.63.

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

- **Price Convergence.** Hourly and daily price differences between the Day-Ahead and Real-Time Energy Markets fluctuate continuously and substantially from positive to negative. The difference between the average day-ahead and real-time prices was -$0.93 per MWh in 2014 and -$0.73 per MWh in 2015. The difference between average day-ahead and real-time prices, by itself, is not a measure of the competitiveness or effectiveness of the Day-Ahead Energy Market.

## Scarcity

- There were no shortage pricing events in 2015.

## Section 3 Recommendations

- The MMU recommends that PJM retain the $1,000 per MWh offer cap in the PJM energy market except when cost-based offers exceed $1,000 per MWh, and other existing rules that limit incentives to exercise market power. (Priority: High. First reported 1999. Status: Partially adopted, 1999.)
- The MMU recommends that the rules governing the application of the TPS test be clarified and documented. (Priority: High. First reported 2010. Status: Not adopted.)
- The MMU recommends, in order to ensure effective market power mitigation when the TPS test is failed, that markup be constant across price and cost offers, that there be at least one cost-based offer using the same fuel as the available price-based offer. (Priority: High. New recommendation. Status: Not adopted.)
- The MMU recommends that in order to ensure effective market power mitigation when the TPS test is failed, the operating parameters in the cost-based offer and the price-based parameter limited schedule (PLS) offer be at least as flexible as the operating parameters in the available non-PLS price-based offer, and that the price-MW pairs in the price based PLS offer be exactly equal to the price based non PLS offer. (Priority: High. New recommendation. Status: Not adopted.)
- The MMU recommends that PJM require all generating units to identify the fuel type associated with each of their offered schedules. (Priority: Low. First reported Q2, 2014. Status: Adopted in full, Q4, 2014.)
- The MMU recommends that under the Capacity Performance construct, PJM recognize the difference between operational parameters that indicate to PJM dispatchers what a unit is capable of during the operating day and the parameters that are used for capacity performance assessment as well as uplift payments. The parameters which determine non-performance charges and the amount of uplift payments to those generators should reflect the flexibility goals of the capacity performance construct. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that capacity performance resources and base capacity resources (during the June through September period) be held to the OEM operating parameters of the capacity market CONE reference resource for performance assessment and energy uplift payments. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that PJM remove non-specific fuel types such as “other” or “co-fire other” from the list of fuel types available for market participants to identify the fuel type associated with their price and cost schedules. (Priority: Medium. First reported Q2, 2015. Status: Not adopted.)
- The MMU recommends that a unit which is not capable of supplying energy consistent with its day-ahead offer should reflect an appropriate outage rather than indicating its availability to supply

energy on an emergency basis. (Priority: Low. First reported 2009. Status: Not Adopted.)

- The MMU recommends that PJM explain how LMPs are calculated when demand response is marginal. The LMPs in excess of $1,800 per MWh on January 7, 2014, were potentially a result of the way in which PJM modeled zonal (not nodal) demand response as a marginal resource. (Priority: Low. First reported Q1, 2014. Status: Not Adopted.)
- The MMU recommends that PJM explicitly state its policy on the use of transmission penalty factors including the level of the penalty factors, the triggers for the use of the penalty factors, the appropriate line ratings to trigger the use of penalty factors, and when the transmission penalty factors will be used to set the shadow price. (Priority: Medium. New recommendation Status: Not adopted.)
- The MMU recommends that PJM routinely review all transmission facility ratings and any changes to those ratings to ensure that the normal, emergency and load dump ratings used in modeling the transmission system are accurate and reflect standard ratings practice. (Priority: Low. First reported 2013. Status: Partially adopted.)
- The MMU recommends that the definition of maximum emergency status in the tariff apply at all times rather than just during maximum emergency events.[60] (Priority: Medium. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM update the outage impact studies, the reliability analyses used in RPM for capacity deliverability and the reliability analyses used in RTEP for transmission upgrades to be consistent with the more conservative emergency operations (post contingency load dump limit exceedance analysis) in the energy market that were implemented in June 2013. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that the roles of PJM and the transmission owners in the decision making process to control for local contingencies be clarified, that PJM's role be strengthened and that the process be made transparent. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM include in the appropriate manual an explanation of the initial creation of hubs, the process for modifying hub definitions and a description of how hub definitions have changed.[61] There is currently no PJM documentation in the tariff or manuals explaining how hubs are created and how their definitions are changed.[62] (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that during hours when a generation bus shows a net withdrawal, the energy withdrawal be treated as load, not negative generation, for purposes of calculating load and load-weighted LMP. The MMU recommends that during hours when a load bus shows a net injection, the energy injection be treated as generation, not negative load, for purposes of calculating generation and load-weighted LMP. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM identify and collect data on available behind the meter generation resources, including nodal location information and relevant operating parameters. (Priority: Low. First reported 2013. Status: Partially adopted.)
- The MMU recommends that PJM continue to enhance its posting of market data to promote market efficiency. (Priority: Medium. First reported 2005. Status: Partially Adopted.)
- The MMU recommends the elimination of FMU and AU adders. FMU and AU adders no longer serve the purpose for which they were created and interfere with the efficient operation of PJM markets. (Priority: Medium. First reported 2012. Status: Adopted partially, Q4, 2014.)

## Section 3 Conclusion

The MMU analyzed key elements of PJM energy market structure, participant conduct and market performance in 2015, including aggregate supply and demand, concentration ratios, three pivotal supplier test

60 PJM. OATT Section: 6A.1.3 Maximum Emergency, (February 25, 2014), p. 1740, 1795.

61 According to minutes from the first meeting of the Energy Market Committee (EMC) on January 28, 1998, the EMC unanimously agreed to be responsible for approving additions, deletions and changes to the hub definitions to be published and modeled by PJM. Since the EMC has become the Market Implementation Committee (MIC), the MIC now appears to be responsible for such changes.

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

results, offer capping, participation in demand response programs, loads and prices.

Average PJM real-time generation increased by 4,490 MW, or 2.8 percent, in the summer of 2015 compared to the summer of 2014, and peak load increased by 2,023 MW. Market concentration levels remained moderate although there is high concentration in the intermediate and peaking segments of the supply curve which adds to concerns about market power when market conditions are tight. The relationship between supply and demand, regardless of the specific market, balanced by market concentration, is referred to as the 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 although aggregate market power does exist during high demand hours.

Prices are a key outcome of markets. Prices vary across hours, days and years for multiple reasons. Price is an indicator of the level of competition in a market although individual prices are not always easy to interpret. In a competitive market, prices are directly related to the marginal cost of the most expensive unit required to serve load in each hour. The pattern of prices within days and across months and years illustrates how prices are directly related to supply and demand conditions and thus also illustrates the potential significance of the impact of the price elasticity of demand on prices. Energy market results in 2015 generally reflected supply-demand fundamentals, although the behavior of some participants during high demand periods is consistent with economic withholding. Economic withholding is the ability to increase markups substantially in tight market conditions. There are additional issues in the energy market including the uncertainties about the pricing and availability of natural gas, the way that generation owners incorporate natural gas costs in offers, and the lack of adequate incentives for unit owners to take all necessary actions to acquire fuel and operate rather than take an outage.

The three pivotal supplier test is applied by PJM on an ongoing basis for local energy markets in order to determine whether offer capping is required for transmission constraints.[63] This is a flexible, targeted real-time measure of market structure which replaced the offer capping of all units required to relieve a constraint. A generation owner or group of generation owners is pivotal for a local market if the output of the owners' generation facilities is required in order to relieve a transmission constraint. When a generation owner or group of owners is pivotal, it has the ability to increase the market price above the competitive level. The three pivotal supplier test explicitly incorporates the impact of excess supply and implicitly accounts for the impact of the price elasticity of demand in the market power tests. The result of the introduction of the three pivotal supplier test was to limit offer capping to times when the local market structure was noncompetitive and specific owners had structural market power. The analysis of the application of the three pivotal supplier test demonstrates that it is working for most hours to exempt owners when the local market structure is competitive and to require offer capping of owners when the local market structure is noncompetitive.

However, there are some issues with the application of mitigation in the Day-Ahead Energy Market and the Real-Time Energy Market when market sellers fail the TPS test. There is no tariff or manual language that defines in detail the application of the TPS test and offer capping in the Day-Ahead Energy Market and the Real-Time Energy Market. In both the Day-Ahead and Real-Time Energy Markets, generators have the ability to avoid mitigation by using varying markups in their price-based offers, offering different operating parameters in their price-based and cost-based offers, and using different fuels in their price-based and cost-based offers. These issues can be resolved by simple rule changes requiring that markup be constant across price and cost offers, that there be at least one cost-based offer using the same fuel as the available price-based offer, that the price-MW pairs in the price based PLS offer be exactly equal to the price based non PLS offer, and requiring cost- based and price-based PLS offers to be at least as flexible as price-based non-PLS offers.

PJM also offer caps units that are committed for reliability reasons in addition to units committed to provide constraint relief. Specifically, units that are committed to provide reactive support and black start

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

service are offer capped in the energy market. These units are committed manually in both the Day-Ahead and Real-Time Energy Markets.

With or without a capacity market, energy market design must permit scarcity pricing when such pricing is consistent with market conditions and constrained by reasonable rules to ensure that market power is not exercised. Scarcity pricing can serve two functions in wholesale power markets: revenue adequacy and price signals. Scarcity pricing for revenue adequacy is not required in PJM. Scarcity pricing for price signals that reflect market conditions during periods of scarcity is required in PJM. Scarcity pricing is also part of an appropriate incentive structure facing both load and generation owners in a working wholesale electric power market design. Scarcity pricing must be designed to ensure that market prices reflect actual market conditions, that scarcity pricing occurs with transparent triggers based on measured reserve levels and transparent 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 net revenue true up mechanism, scarcity pricing can be a mechanism to appropriately increase reliance on the energy market as a source of revenues and incentives in a competitive market without reliance on the exercise of market power. PJM implemented scarcity pricing rules in 2012. There are significant issues with the scarcity pricing net revenue true up mechanism in the PJM scarcity pricing design, which will create issues when scarcity pricing occurs. There are also significant issues with PJM's scarcity pricing rules, including the absence of a clear trigger based on measured reserve levels (the current triggers are based on estimated reserves) and the lack of adequate locational scarcity pricing options.

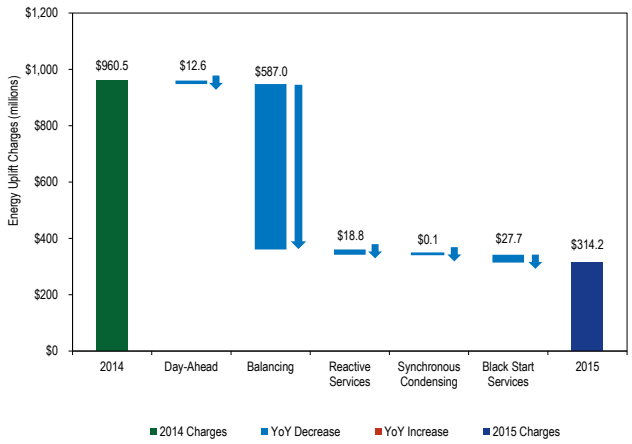
The overall energy market results support the conclusion that energy prices in PJM are set, generally, by marginal units operating at, or close to, their marginal costs, although this was not always the case during the high demand hours in 2014 or 2015. This is evidence of generally competitive behavior and competitive market outcomes, although the behavior of some participants during the high demand periods in the first quarter is consistent with economic withholding. Given the structure of the energy market which can permit the exercise of aggregate market power at times of high demand, the tighter market conditions and the change in some participants' behavior are sources of concern in the energy market and provide a reason to use cost as the sole basis for hourly changes in offers or offers greater than $1,000 per MWh. The MMU concludes that the PJM energy market results were competitive in 2015.

## Overview: Section 4, "Energy Uplift"

### Energy Uplift Results

- **Energy Uplift Charges.** Total energy uplift charges decreased by $646.3 million, or 67.3 percent, in 2015 compared to 2014, from $960.5 million to $314.2 million.
- **Energy Uplift Charges Categories.** The decrease of $646.3 million in 2015 is comprised of a $12.6 million decrease in day-ahead operating reserve charges, a $587.0 million decrease in balancing operating reserve charges, an $18.8 million decrease in reactive services charges, a $0.1 million decrease in synchronous condensing charges and a $27.7 million decrease in black start services charges.
- **Average Effective Operating Reserve Rates in the Eastern Region.** Day-ahead load paid $0.115 per MWh, real-time load paid $0.050 per MWh, a DEC paid $1.187 per MWh and an INC and any load, generation or interchange transaction deviation paid $1.072 per MWh.
- **Average Effective Operating Reserve Rates in the Western Region.** Day-ahead load paid $0.115 per MWh, real-time load paid $0.042 per MWh, a DEC paid $1.151 per MWh and an INC and any load, generation or interchange transaction deviation paid $1.036 per MWh.
- **Reactive Services Rates.** The DPL, ATSI and Dominion control zones had the three highest local voltage support rates: $0.124, $0.056 and $0.027 per MWh. The reactive transfer interface support rate averaged $0.0019 per MWh.

Figure 6 Energy uplift charges change from 2014 to 2015 by category




## Characteristics of Credits

- **Types of units.** Combined cycles received 24.0 percent of all day-ahead generator credits and 39.1 percent of all balancing generator credits. Combustion turbines and diesels received 85.6 percent of the lost opportunity cost credits. Coal units received 39.6 percent of all reactive services credits.
- **Concentration of Energy Uplift Credits.** The top 10 units receiving energy uplift credits received 34.2 percent of all credits. The top 10 organizations received 78.0 percent of all credits. Concentration indexes for energy uplift categories classify them as highly concentrated. Day-ahead operating reserves HHI was 5828, balancing operating reserves HHI was 3740, lost opportunity cost HHI was 3788 and reactive services HHI was 9093.
- **Economic and Noneconomic Generation.** In 2015, 88.0 percent of the day-ahead generation eligible for operating reserve credits was economic and 73.2 percent of the real-time generation eligible for operating reserve credits was economic.
- **Day-Ahead Unit Commitment for Reliability.** In 2015, 1.9 percent of the total day-ahead generation MWh was scheduled as must run by PJM, of which 44.0 percent received energy uplift payments.

## Geography of Charges and Credits

- In 2015, 88.4 percent of all uplift charges allocated regionally (day-ahead operating reserves and balancing operating reserves) were paid by transactions at control zones or buses within a control zone, demand and generation, 3.2 percent by transactions at hubs and aggregates and 8.3 percent by interchange transactions at interfaces.
- Generators in the Eastern Region received 68.2 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.
- Generators in the Western Region received 31.5 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.
- External generators received 0.2 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.

## Energy Uplift Issues

- **Lost Opportunity Cost Credits.** In 2015, lost opportunity cost credits decreased by $71.1 million compared to 2014. In 2015, resources in the top three control zones receiving lost opportunity cost credits, AEP, Dominion and ComEd, accounted for 47.1 percent of all lost opportunity cost credits, 41.9 percent of all day-ahead generation from pool-scheduled combustion turbines and diesels, 39.6 percent of all day-ahead generation not committed in real time by PJM from those unit types and 39.0 percent of all day-ahead generation not committed in real time by PJM and receiving lost opportunity cost credits from those unit types.
- **Black Start Service Units.** Certain units located in the AEP Control Zone were relied on for their black start capability on a regular basis during periods when the units were not economic. These black start units provided black start service under the ALR option, which means that the units had to run in order to provide black start services even if the units were not economic. PJM replaced all ALR units as black start resources as of April 2015. In 2015, the cost of the noneconomic operation of ALR units in the AEP Control Zone was $4.8 million, a decrease of $27.8 million compared to 2014.
- **Con Edison – PJM Transmission Service Agreements Support.** Certain units located near the boundary between New Jersey and New York City have been operated to support the transmission service agreements between Con Ed and PJM, formerly known as the Con Ed – PSEG Wheeling Contracts.

These units are often run out of merit and received substantial operating reserves credits.

## Energy Uplift Recommendations

- **Impact of Quantifiable Recommendations.** The impact of implementing the recommendations related to energy uplift proposed by the MMU on the rates paid by participants would be significant. For example, in 2015, the average rate paid by a DEC in the Eastern Region would have been $0.149 per MWh under the MMU proposal, which is $1.038 per MWh, or 87.4 percent, lower than the actual average rate paid.

## Section 4 Recommendations

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

- The MMU recommends that PJM not use closed loop interface constraints to artificially override the nodal prices that are based on fundamental LMP logic in order to: accommodate rather than resolve the inadequacies of the demand side resource capacity product; address the inability of the power flow model to incorporate the need for reactive power; accommodate rather than resolve the flaws in PJM's approach to scarcity pricing; or for any other reason. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM not use price setting logic to artificially override the nodal prices that are based on fundamental LMP logic in order to reduce uplift. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that PJM initiate an analysis of the reasons why some combustion turbines and diesels scheduled in the Day-Ahead Energy Market are not called in real time when they are economic. (Priority: Medium. First Reported 2012. Status: Not adopted.)
- The MMU recommends that PJM clearly identify and classify all reasons for incurring operating reserves in the Day-Ahead and the Real-Time Energy Markets and the associated operating reserve charges in order for all market participants to be made aware of the reasons for these costs and to help ensure a long term solution to the issue of how to allocate the costs of operating reserves. (Priority: Medium. First reported 2011. Status: Adopted 2014.)
- The MMU recommends that PJM revise the current operating reserve confidentiality rules in order to allow the disclosure of complete information about the level of operating reserve charges by unit and the detailed reasons for the level of operating reserve credits by unit in the PJM region. (Priority: High. First reported 2013. Status: Not adopted. Stakeholder process.)
- The MMU recommends the elimination of the day-ahead operating reserve category to ensure that units receive an energy uplift payment based on their real-time output and not their day-ahead scheduled output. (Priority: Medium. First reported 2013. Status: Not adopted. Stakeholder process.)
- The MMU recommends reincorporating the use of net regulation revenues as an offset in the calculation of balancing operating reserve credits. (Priority: Medium. First reported 2009. Status: Not adopted. Stakeholder process.)
- The MMU recommends not compensating self-scheduled units for their startup cost when the units are scheduled by PJM to start before the self-scheduled hours. (Priority: Low. First reported 2013. Status: Not adopted. Stakeholder process.)
- The MMU recommends seven modifications to the energy lost opportunity cost calculations:
  - The MMU recommends that the lost opportunity cost in the energy market be calculated using the schedule on which the unit was scheduled to run in the energy market. (Priority: High. First reported 2012. Status: Adopted 2015.)
  - The MMU recommends including no load and startup costs as part of the total avoided costs in the calculation of lost opportunity cost credits paid to combustion turbines and diesels scheduled in the Day-Ahead Energy Market but not committed in real time. (Priority: Medium. First reported 2012. Status: Adopted 2015.)
  - The MMU recommends using the entire offer curve and not a single point on the offer curve to

calculate energy lost opportunity cost. (Priority: Medium. First reported 2012. Status: Adopted 2015.)

- The MMU recommends calculating LOC based on 24 hour daily periods or multi-hour segments of hours for combustion turbines and diesels scheduled in the Day-Ahead Energy Market but not committed in real time. (Priority: Medium. First reported 2014. Status: Not adopted.)
- The MMU recommends that units scheduled in the Day-Ahead Energy Market and not committed in real time should be compensated for LOC based on their real-time desired and achievable output, not their scheduled day-ahead output. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that units scheduled in the Day-Ahead Energy Market and not committed in real time be compensated for LOC incurred within an hour. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that only flexible fast start units (startup plus notification times of 30 minutes or less) and short minimum run times (one hour or less) be eligible by default for the LOC compensation to units scheduled in the Day-Ahead Energy Market and not committed in real time. Other units should be eligible for LOC compensation only if PJM explicitly cancels their day-ahead commitment. (Priority: Medium. First reported 2015. Status: Not adopted.)

- The MMU recommends that up to congestion transactions be required to pay energy uplift charges. (Priority: High. First reported 2011. Status: Not adopted. Stakeholder process.)
- The MMU recommends eliminating the use of internal bilateral transactions (IBTs) in the calculation of deviations used to allocate balancing operating reserve charges. (Priority: High. First reported 2013. Status: Not adopted. Stakeholder process.)
- The MMU recommends allocating the energy uplift payments to units scheduled as must run in the Day-Ahead Energy Market for reasons other than voltage/reactive or black start services as a reliability charge to real-time load, real-time exports and real-time wheels. (Priority: Medium. First reported 2014. Status: Not adopted. Stakeholder process.)
- The MMU recommends reallocating the operating reserve credits paid to units supporting the Con Edison – PJM Transmission Service Agreements. (Priority: Medium. First reported 2013. Status: Not adopted. Stakeholder process.)
- The MMU recommends that the total cost of providing reactive support be categorized and allocated as reactive services. Reactive services credits should be calculated consistent with the operating reserve credits calculation. (Priority: Medium. First reported 2012. Status: Not adopted. Stakeholder process.)
- The MMU recommends including real-time exports and real-time wheels in the allocation of the cost of providing reactive support to the 500 kV system or above, which is currently allocated solely to real-time RTO load. (Priority: Low. First reported 2013. Status: Not adopted. Stakeholder process.)
- The MMU recommends enhancing the current energy uplift allocation rules to reflect the elimination of day-ahead operating reserves, the timing of commitment decisions and the commitment reasons. (Priority: High. First reported Q2, 2012. Status: Not adopted. Stakeholder process.)

## Section 4 Conclusion

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

In PJM all energy payments to demand response resources are also uplift payments. The energy payments to these resources are not part of the supply and demand balance, they are not paid by LMP revenues

and therefore the energy payments to demand response resources have to be paid as out of market uplift. The energy payments to economic DR are funded by real-time load and real-time exports. The energy payments to emergency DR are funded by participants with net energy purchases in the Real-Time Energy Market.

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

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

One part of addressing the level and allocation of uplift payments is to eliminate all day-ahead operating reserve credits. It is illogical and unnecessary to pay units day-ahead operating reserve credits because units do not incur any costs to run and any revenue shortfalls are addressed by balancing operating reserve credits.

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

PJM's goal should be to minimize the total level of energy uplift paid and to ensure that the associated charges are paid by all those whose market actions result in the incurrence of such charges. For example, up to congestion transactions continue to pay no energy uplift charges, which means that all others who pay these charges are paying too much. In addition, the netting of transactions against internal bilateral transactions should be eliminated. The goal should be to minimize the total incurred energy uplift charges and to increase the transactions over which those charges are spread in order to reduce the impact of energy uplift charges on markets. The result would be to reduce the level of per MWh charges, to reduce the uncertainty associated with uplift charges and to reduce the impact of energy uplift charges on decisions about how and when to participate in PJM markets.

But it is also important that the reduction of uplift payments not be a goal to be achieved at the expense of the fundamental logic of an LMP system. For example, the use of closed loop interfaces to reduce uplift should be eliminated because it is not consistent with LMP fundamentals and constitutes a form of subjective price setting. The same is true of what PJM terms its price setting logic.

## Overview: Section 5, "Capacity Market"

### RPM Capacity Market

#### Market Design

The Reliability Pricing Model (RPM) Capacity Market is a forward-looking, annual, locational market, with a must offer requirement for Existing Generation Capacity Resources and mandatory participation by load, with performance incentives, that includes clear market power mitigation rules and that permits the direct participation of demand-side resources.[64]

Under RPM, capacity obligations are annual. Base Residual Auctions (BRA) are held for Delivery Years

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

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.[65] 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.[66] 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.[67]

The 2016/2017 RPM Second Incremental Auction, 2018/2019 RPM Base Residual Auction, 2016/2017 Capacity Performance Transition Incremental Auction, 2017/2018 Capacity Performance Transition Incremental Auction, and 2017/2018 RPM First Incremental Auction were conducted in 2015. The Base Residual Auction for the 2018/2019 Delivery Year had been delayed.[68] The Capacity Performance (CP) Transition Incremental Auctions (IAs) were held as part of a five year transition to a single capacity product type in the 2020/2021 Delivery Year. Participation in the CP Transition IAs was voluntary. If a resource cleared a CP Transition IA and had a prior commitment for the relevant Delivery Year, the existing commitment was converted to a CP commitment which is subject to the CP performance requirements and Non-Performance Charges. The Transition IAs were not designed to minimize the cost of purchasing Capacity Performance resources for the two delivery years and were not designed to maximize economic welfare for the two delivery years.[69]

One June 9, 2015, FERC accepted changes to the PJM capacity market rules proposed in PJM's Capacity Performance (CP) filing.[70] For a transition period during the 2018/2019 and 2019/2020 Delivery Years, PJM will procure two product types, Capacity Performance and Base Capacity. PJM also procured Capacity Performance resources in two transition auctions for Delivery Years 2016/2017 and 2017/2018. Effective with the 2020/2021 Delivery Year, PJM will procure a single capacity product, Capacity Performance. CP Resources are expected to be available and capable of providing energy and reserves when needed at any time during the Delivery Year.[71] Effective for the 2018/2019 through the 2019/2020 Delivery Years, a Base Capacity Demand Resource Constraint and a Base Capacity Resource Constraint are established for each modeled LDA. These maximum quantities are set for reliability purpose to limit the quantity procured of the less available products, including Base Capacity Generation Resources, Base Capacity Demand Resources, and Base Capacity Energy Efficiency Resources.

RPM prices are locational and may vary depending on transmission constraints.[72] 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, and the performance incentives have been strengthened significantly under the Capacity Performance modifications to RPM. Under RPM there are explicit market power mitigation rules that define the must offer requirement, that define structural market power based on the marginal cost of capacity, that define offer caps, that define the minimum offer price, and that have flexible criteria for competitive offers by new entrants. Demand Resources and Energy Efficiency Resources may be offered directly into RPM Auctions and receive the clearing price without mitigation.

## Market Structure

- **PJM Installed Capacity.** During 2015, PJM installed capacity decreased 6,043.2 MW or 3.3 percent,

65 See 126 FERC ¶ 61,275 (2009) at P 86.
66 See *PJM Interconnection, L.L.C.*, Letter Order in Docket No. ER10-366-000 (January 22, 2010).
67 See 126 FERC ¶ 61,275 (2009) at P 88.
68 151 FERC ¶ 61,067 (2015).
69 The MMU will publish a detailed report on the operation and design of the transition auctions in 2016.
70 See Docket No. ER15-623-000 (December 12, 2014) and 151 FERC ¶ 61,208 (2015).
71 See PJM. "Manual 18: PJM Capacity Market," Revision 30 (December 17, 2015), p. 7.
72 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.

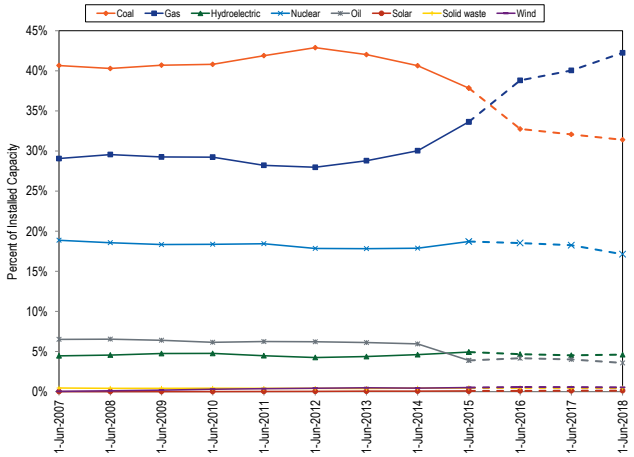
from 183,726 MW on January 1 to 177,682.8 MW on December 31. Installed capacity includes net capacity imports and exports and can vary on a daily basis.

- **PJM Installed Capacity by Fuel Type.** Of the total installed capacity on December 31, 2015, 37.5 percent was coal; 34.0 percent was gas; 18.6 percent was nuclear; 3.9 percent was oil; 4.9 percent was hydroelectric; 0.5 percent was wind; 0.4 percent was solid waste; and 0.1 percent was solar.

### Table 11 PJM installed capacity (By fuel source): January 1, May 31, June 1, and December 31, 2015

| | 1-Jan-15 | | 31-May-15 | | 1-Jun-15 | | 31-Dec-15 | |
|---|---|---|---|---|---|---|---|---|
| | MW | Percent | MW | Percent | MW | Percent | MW | Percent |
| Coal | 72,741.3 | 39.6% | 72,343.5 | 39.5% | 66,878.1 | 37.8% | 66,674.8 | 37.5% |
| Gas | 59,662.6 | 32.5% | 59,862.3 | 32.7% | 59,460.1 | 33.6% | 60,487.4 | 34.0% |
| Hydroelectric | 8,765.3 | 4.8% | 8,690.8 | 4.7% | 8,698.8 | 4.9% | 8,787.5 | 4.9% |
| Nuclear | 32,947.1 | 17.9% | 33,078.4 | 18.1% | 33,071.5 | 18.7% | 33,071.5 | 18.6% |
| Oil | 7,907.6 | 4.3% | 7,299.7 | 4.0% | 6,853.4 | 3.9% | 6,851.8 | 3.9% |
| Solar | 97.5 | 0.1% | 97.5 | 0.1% | 128.0 | 0.1% | 128.0 | 0.1% |
| Solid waste | 781.9 | 0.4% | 781.9 | 0.4% | 771.3 | 0.4% | 769.4 | 0.4% |
| Wind | 822.7 | 0.4% | 822.7 | 0.4% | 876.2 | 0.5% | 912.4 | 0.5% |
| Total | 183,726.0 | 100.0% | 182,976.8 | 100.0% | 176,737.4 | 100.0% | 177,682.8 | 100.0% |

### Figure 7 Percentage of PJM installed capacity (By fuel source): June 1, 2007 through June 1, 2018




- **Supply.** Total internal capacity available to offer in the Base Residual Auction for the relevant Delivery Year increased 8,321.5 MW from 196,235.8 MW on June 1, 2014, to 204,557.3 MW on June 1, 2015. This increase was the result of new generation (6,786.1 MW), net generation capacity modifications (cap mods) (-5,118.9 MW), Demand Resource (DR) modifications (5,441.4 MW), Energy Efficiency (EE) modifications (220.1 MW), the EFORd effect due to lower sell offer EFORds (938.4 MW), and lower load management UCAP conversion factor (54.4 MW).
- **Demand.** There was a 902.4 MW decrease in the RPM reliability requirement from 178,086.5 MW on June 1, 2014, to 177,184.1 MW on June 1, 2015. The 902.4 MW decrease in the RTO Reliability Requirement was a result of a 1,718.2 MW decrease in the forecast peak load in UCAP terms holding the Forecast Pool Requirement (FPR) constant at the 2014/2015 level offset by a 815.8 MW increase attributable to the change in FPR. On June 1, 2015, PJM EDCs and their affiliates maintained a large market share of load obligations under RPM, together totaling 65.1 percent, down from 71.1 percent on June 1, 2014.
- **Market Concentration.** In the 2016/2017 RPM Second Incremental Auction, the 2018/2019 RPM Base Residual Auction, and the 2017/2018 RPM First Incremental Auction all participants in the total PJM market as well as the LDA RPM markets failed the three pivotal supplier (TPS) test.[73] The TPS test was not applied in the 2016/2017 Capacity Performance (CP) Transition Incremental Auction and the 2017/2018 CP Transition Incremental Auction. All offers in the Transition Auctions were subject to overall offer caps. Offer caps were applied to all sell offers for resources which were subject to mitigation when the Capacity Market Seller did not pass the test, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, increased the market clearing price.[74] [75] [76]

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

74 See PJM. OATT Attachment DD § 6.5.

75 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.

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

- **Imports and Exports.** Of the 5,135.8 MW of imports in the 2018/2019 RPM Base Residual Auction, 4,687.9 MW cleared. Of the cleared imports, 2,509.1 MW (53.5 percent) were from MISO.
- **Demand-Side and Energy Efficiency Resources.** Capacity in the RPM load management programs was 12,149.5 MW for June 1, 2015, as a result of cleared capacity for Demand Resources and Energy Efficiency Resources in RPM Auctions for the 2015/2016 Delivery Year (16,643.3 MW) less replacement capacity from sources other than Demand Resources and Energy Efficiency (4,493.8 MW).

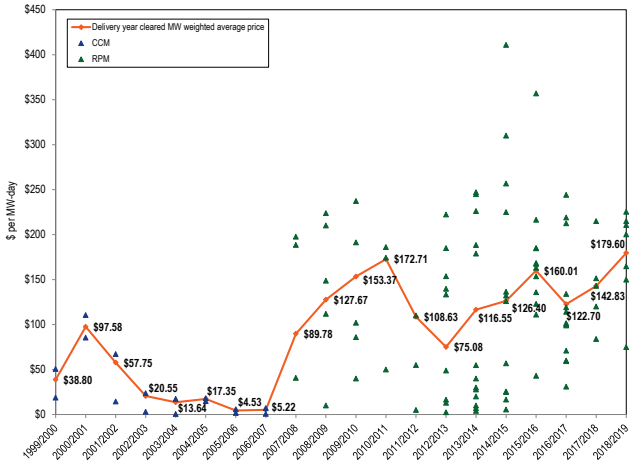
## Market Conduct

- **2015/2016 RPM Base Residual Auction.** Of the 1,168 generation resources which submitted offers, unit-specific offer caps were calculated for 196 generation resources (16.8 percent). The MMU calculated offer caps for 670 generation resources (57.4 percent), of which 478 were based on the technology specific default (proxy) ACR values.
- **2015/2016 RPM First Incremental Auction.** Of the 131 generation resources which submitted offers, unit-specific offer caps were calculated for 20 generation resources (15.3 percent). The MMU calculated offer caps for 45 generation resources (34.4 percent), of which 25 were based on the technology specific default (proxy) ACR values.
- **2015/2016 RPM Second Incremental Auction.** Of the 80 generation resources which submitted offers, unit-specific offer caps were calculated for 16 generation resources (20.0 percent). The MMU calculated offer caps for 25 generation resources (31.3 percent), of which nine were based on the technology specific default (proxy) ACR values.
- **2015/2016 RPM Third Incremental Auction.** Of the 214 generation resources which submitted offers, unit-specific offer caps were calculated for seven generation resources (3.3 percent). The MMU calculated offer caps for 23 generation resources (10.7 percent), of which 16 were based on the technology specific default (proxy) ACR values.
- **2016/2017 RPM Base Residual Auction.** Of the 1,199 generation resources which submitted offers, unit-specific offer caps were calculated for 152 generation resources (12.7 percent). The MMU calculated offer caps for 638 generation resources (53.2 percent), of which 491 were based on the technology specific default (proxy) ACR values.
- **2016/2017 RPM First Incremental Auction.** Of the 115 generation resources which submitted offers, unit-specific offer caps were calculated for 37 generation resources (32.2 percent). The MMU calculated offer caps for 62 generation resources (53.9 percent), of which 25 were based on the technology specific default (proxy) ACR values.
- **2016/2017 RPM Second Incremental Auction.** Of the 101 generation resources that submitted offers, the MMU calculated offer caps for 45 generation resources (44.6 percent), of which 21 were based on the technology specific default (proxy) ACR values and 24 were unit-specific offer caps (23.8 percent).
- **2016/2017 Capacity Performance Transition Incremental Auction.** All 709 generation resources which submitted offers in the 2016/2017 CP Transition Incremental Auction were subject to an offer cap of $165.27 per MW-day, which is 50 percent of the Net Cost of New Entry (CONE) used in the 2016/2017 RPM Base Residual Auction.
- **2017/2018 RPM Base Residual Auction.** Of the 1,202 generation resources which submitted offers, unit-specific offer caps were calculated for 131 generation resources (10.9 percent). The MMU calculated offer caps for 531 generation resources (44.2 percent), of which 400 were based on the technology specific default (proxy) ACR values.
- **2017/2018 Capacity Performance Transition Incremental Auction.** All 785 generation resources which submitted offers in the 2017/2018 CP Transition Incremental Auction were subject to an offer cap of $210.83 per MW-day, which is 60 percent of the Net Cost of New Entry (CONE) used in the 2017/2018 RPM Base Residual Auction.
- **2017/2018 RPM First Incremental Auction.** Of the 118 generation resources that submitted offers, the MMU calculated offer caps for 53 generation resources (44.9 percent), of which 36 were based on the technology specific default (proxy) ACR values and 17 were unit-specific offer caps (14.4 percent).
- **2018/2019 RPM Base Residual Auction.** Of the 473 generation resources that submitted Base Capacity offers, the MMU calculated offer caps for 219

generation resources (46.3 percent), of which 166 (35.1 percent) were based on the technology specific default (proxy) ACR values and 53 were unit-specific offer caps (11.2 percent). Of the 992 generation resources that submitted Capacity Performance offers, the MMU calculated unit specific offer caps for 35 generation resources (3.5 percent).

## Market Performance

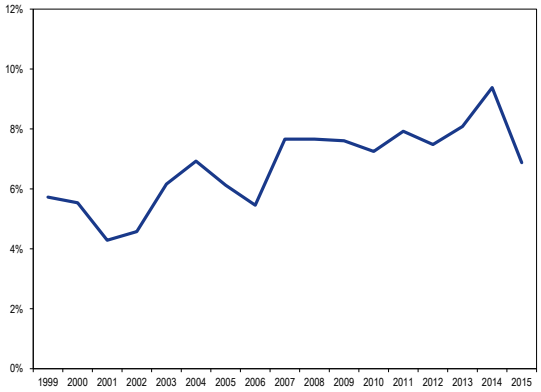
### Figure 8 History of PJM capacity prices: 1999/2000 through 2018/2019[77]




- The 2015/2016 RPM Third Incremental Auction, the 2016/2017 RPM Second Incremental Auction, 2018/2019 RPM Base Residual Auction, 2016/2017 Capacity Performance Transition Incremental Auction, 2017/2018 Capacity Performance Transition Incremental Auction, and 2017/2018 RPM First Incremental Auction were conducted in 2015. The weighted average capacity price for the 2016/2017 Delivery Year is $122.70 per MW-day, including all RPM Auctions for the 2016/2017 Delivery Year held through 2015. The weighted average capacity price for the 2017/2018 Delivery Year is $142.83, including all RPM Auctions for the 2017/2018 Delivery Year held through 2015. The weighted average capacity price for the 2018/2019 Delivery Year is $179.60, including all RPM Auctions for the 2018/2019 Delivery Year held through 2015.RPM net excess increased 383.6 MW from 5,472.3 MW on June 1, 2014, to 5,855.9 MW on June 1, 2015.
- For the 2015/2016 Delivery Year, RPM annual charges to load are $9.6 billion.
- The Delivery Year weighted average capacity price was $126.40 per MW-day in 2014/2015 and $160.01 per MW-day in 2015/2016.

## Generator Performance

### Figure 9 Trends in the PJM equivalent demand forced outage rate (EFORd): 1999 through 2015




- **Forced Outage Rates.** The average PJM EFORd for 2015 was 6.9 percent, a decrease from 9.4 percent for 2014.[78]
- **Generator Performance Factors.** The PJM aggregate equivalent availability factor for 2015 was 83.7 percent, an increase from 82.2 percent for 2014.
- **Outages Deemed Outside Management Control (OMC).** In 2015, 4.2 percent of forced outages were classified as OMC outages, a decrease from 7.7 percent in 2014. In 2015, 0.6 percent of OMC outages were due to lack of fuel, compared to 0.5 percent in 2014.

77 The 1999/2000-2006/2007 capacity prices are CCM combined market, weighted average prices. The 2007/2008-2018/2019 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. For the 2014/2015 and subsequent Delivery Years, only the prices for Annual Resources or Capacity Performance Resources are plotted.

78 The generator performance analysis includes all PJM capacity resources for which there are data in the PJM generator availability data systems (GADS) database. This set of capacity resources may include generators in addition to those in the set of generators committed as capacity resources in RPM. Data is for the twelve months ending December 31, as downloaded from the PJM GADS database on January 27, 2016. 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.

## Section 5 Recommendations[79]

The MMU recognizes that PJM has implemented the Capacity Performance Construct to replace some of the existing core market rules and to address fundamental performance incentive issues. The MMU recognizes that the Capacity Performance Construct addresses many of the MMU's recommendations. The MMU's recommendations are based on the existing capacity market rules. The status is reported as adopted if the recommendation was included in FERC's order approving PJM's Capacity Performance filing.[80]

- The MMU recommends the enforcement of a consistent definition of capacity resource. The MMU recommends that the requirement to be a physical resource be enforced and enhanced. The requirement to be a physical resource should apply at the time of auctions and should also constitute a commitment to be physical in the relevant Delivery Year. The requirement to be a physical resource should be applied to all resource types, including planned generation, demand resources and imports.[81] [82] (Priority: High. First reported 2013. Status: Not adopted. Pending before FERC.)
- The MMU recommends that the test for determining modeled Locational Deliverability Areas in RPM be redefined. A detailed reliability analysis of all at risk units should be included in the redefined model. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that there be an explicit requirement that Capacity Resource offers in the Day-Ahead Energy Market be competitive, where competitive is defined to be the short run marginal cost of the units. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that clear, explicit operational protocols be defined for recalling the energy output of Capacity Resources when PJM is in an emergency condition. PJM has modified these protocols, but they need additional clarification and operational details. (Priority: Low. First reported 2010. Status: Partially adopted.)
- The MMU recommends that the net revenue calculation used by PJM to calculate the net Cost of New Entry (CONE) VRR parameter reflect the actual flexibility of units in responding to price signals rather than using assumed fixed operating blocks that are not a result of actual unit limitations.[83,84] The result of reflecting the actual flexibility is higher net revenues, which affect the parameters of the RPM demand curve and market outcomes. (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that modifications to existing resources not be treated as new resources for purposes of market power related offer caps or MOPR offer floors. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends that, as part of the MOPR unit specific standard of review, all projects be required to use the same basic modeling assumptions. That is the only way to ensure that projects compete on the basis of actual costs rather than on the basis of modeling assumptions.[85] (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends two changes to the RPM solution methodology related to make-whole payments and the iterative reconfiguration of the VRR curve:
  - The MMU recommends changing the RPM solution methodology to explicitly incorporate the cost of make-whole payments in the objective function. (Priority: Medium. First reported 2014. Status: Not adopted.)
  - The MMU also recommends changing the RPM solution methodology to define variables for the nesting relationships in the BRA optimization model directly rather than employing the current

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

80 *PJM Interconnection, L.L.C.*, 151 FERC ¶ 61,208 (June 9, 2015).

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

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

83 See *PJM Interconnection, L.L.C.*, Docket No. ER12-513-000 (December 1, 2011) ("Triennial Review").

84 See the *2012 State of the Market Report for PJM*, Volume II, Section 6, Net Revenue.

85 See 143 FERC ¶ 61,090 (2013) ("We encourage PJM and its stakeholders to consider, for example, whether the unit-specific review process would be more effective if PJM requires the use of common modeling assumptions for establishing unit-specific offer floors while, at the same time, allowing sellers to provide support for objective, individual cost advantages. Moreover, we encourage PJM and its stakeholders to consider these modifications to the unit-specific review process together with possible enhancements to the calculation of Net CONE."); see also, Comments of the Independent Market Monitor for PJM, Docket No. ER13-535-001 (March 25, 2013); Complaint of the Independent Market Monitor for PJM v. Unnamed Participant, Docket No. EL12-63-000 (May 1, 2012); Motion for Clarification of the Independent Market Monitor for PJM, Docket No. ER11-2875-000, et al. (February 17, 2012); Protest of the Independent Market Monitor for PJM, Docket No. ER11-2875-002 (June 2, 2011); Comments of the Independent Market Monitor for PJM, Docket Nos. EL11-20 and ER11-2875 (March 4, 2011).

iterative approach, in order to improve the efficiency and stability. (Priority: Medium. First reported 2014. Status: Not adopted.)

- The MMU recommends that the use of the 2.5 percent demand adjustment (Short Term Resource Procurement Target) be terminated immediately. The 2.5 percent should be added back to the overall market demand curve. (Priority: Medium. First reported 2013. Status: Adopted.)
- The MMU recommends that the definition of demand side resources be modified in order to ensure that such resources be fully substitutable for other generation capacity resources. Both the Limited and the Extended Summer DR products should be eliminated in order to ensure that the DR product has the same unlimited obligation to provide capacity year round as generation capacity resources. (Priority: High. First reported 2013. Status: Adopted.)
- The MMU recommends three changes with respect to capacity imports into PJM:
  - The MMU recommends that all capacity have firm transmission to the PJM border acquired prior to the offering in an RPM auction. (Priority: High. First reported 2014. Status: Adopted.)
  - The MMU recommends that all capacity imports be required to be pseudo tied prior to the relevant Delivery Year in order to ensure that imports are as close to full substitutes for internal, physical capacity resources as possible. (Priority: High. First reported 2014. Status: Adopted.)
  - The MMU recommends that all resources importing capacity into PJM accept a must offer requirement. (Priority: High. First reported 2014. Status: Adopted.)
- The MMU recommends improvements to the performance incentive requirements of RPM:
  - The MMU recommends that Generation Capacity Resources be paid on the basis of whether they produce energy when called upon during any of the hours defined as critical. One hundred percent of capacity market revenue should be at risk rather than only fifty percent. (Priority: High. First reported 2012. Status: Adopted.)
  - The MMU recommends that a unit which is not capable of supplying energy consistent with its day-ahead offer should reflect an appropriate outage. (Priority: Medium. First reported 2013. Status: Not adopted. Pending before FERC.)
  - The MMU recommends that PJM eliminate all OMC outages from the calculation of forced outage rates used for any purpose in the PJM Capacity Market. (Priority: Medium. First reported 2013. Status: Adopted.)
  - The MMU recommends that PJM eliminate the broad exception related to lack of gas during the winter period for single-fuel, natural gas-fired units.[86] (Priority: Medium. First reported 2013. Status: Adopted.)

## Section 5 Conclusion

The analysis of PJM Capacity Markets begins with market structure, which provides the framework for the actual behavior or conduct of market participants. The analysis examines participant behavior within that market structure. In a competitive market structure, market participants are constrained to behave competitively. The analysis examines market performance, measured by price and the relationship between price and marginal cost, that results from the interaction of market structure and participant behavior.

The MMU found serious market structure issues, measured by the three pivotal supplier test results, but no exercise of market power in the PJM Capacity Market in 2015. Explicit market power mitigation rules in the RPM construct offset the underlying market structure issues in the PJM Capacity Market under RPM. The PJM Capacity Market results were competitive in 2015.

## Overview: Section 6, "Demand Response"

- **Demand Response Jurisdiction.** In a panel decision issued May 23, 2014, the U.S. Court of Appeals for the District of Columbia Circuit vacated Order No. 745, which provided for payment of demand-

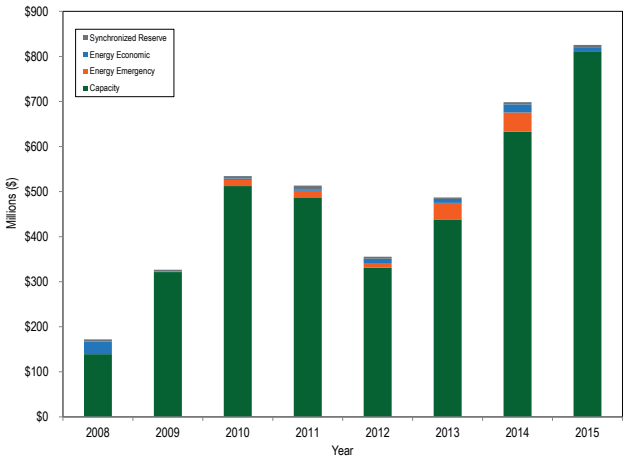
86 See OATT Attachment DD § 10(e). For more on this issue and related incentive issues, see the MMU's White Paper included in: Monitoring Analytics, LLC and PJM Interconnection, LLC, "*Capacity in the PJM Market*," <http://www.monitoringanalytics.com/reports/Reports/2012/IMM_And_PJM_Capacity_White_Papers_On_OPSI_Issues_20120820.pdf> (August 20, 2012).

side resources at full LMP.[87] The court found that the FERC lacked jurisdiction to issue Order No. 745 because the "rule entails direct regulation of the retail market - a matter exclusively within state control."[88] On January 25, 2016, the Supreme Court voted 6-2 to reverse the decision of the lower court.[89] The result is that FERC retains jurisdiction over demand-side programs.

- **Demand Response Activity.** Demand response includes the economic program and the emergency program. The economic program includes the response to energy prices in the energy market. The emergency program is the capacity market program which includes both capacity payments and associated energy revenues when the capacity is called on to respond. The emergency program accounted for 98.4 percent of all revenue received by demand response providers, the economic program for 1.0 percent and synchronized reserve for 0.6 percent. In 2015, total emergency revenue increased by $136.4 million, or 20.2 percent, from $675.7 million in 2014 to $812.2 in 2015. Capacity market revenue increased by $178.9 million, or 28.3 percent, from $632.8 million in 2014 to $811.7 million 2015.[90] Emergency energy revenue decreased by $42.5 million, from $43.0 million in 2014 to $0.5 million in 2015. Economic program revenue decreased by $9.5 million, from $17.8 million in 2014 to $8.3 million in 2015, a 53.2 percent decrease.[91] Synchronized reserve revenue increased by $43.3 thousand, a 0.6 percent increase. Total demand response revenue in 2015 increased by 18.2 percent from $675.7 million 2014 to $825.6 million in 2015. Not all DR activities in 2015 have been reported to PJM at the time of this report.

  All demand response energy payments are uplift. LMP does not cover demand response energy payments although emergency demand response can and does set LMP. Emergency demand response energy costs are paid by PJM market participants in proportion to their net purchases in the real-time market. Economic demand response energy costs are paid by real-time exports from the PJM Region and real-time loads in each zone for which the load-weighted average real-time LMP for the hour during which the reduction occurred is greater than the single system price determined under the net benefits test for that month.[92]

**Figure 10 Demand response revenue by market: 2008 through 2015**




- **Demand Response Market Concentration.** The ownership of economic demand response was highly concentrated in 2014 and 2015. The HHI for economic demand response reductions increased from 7713 in 2014 to 7862 in 2015. The ownership of emergency demand response was moderately concentrated in 2015. The HHI for emergency demand response registrations was 1760 for the 2014/2015 Delivery Year and 1497 for the 2015/2016 Delivery Year. In 2015, the four largest companies contributed 65.3 percent of all registered emergency demand response resources.
- **Locational Dispatch of Demand Resources.** Beginning with the 2014/2015 Delivery Year, demand resources are dispatchable for mandatory reduction on a subzonal basis, defined by zip codes, only if the subzone is defined at least one day before it is dispatched. More locational dispatch of demand resources in a nodal market improves market efficiency. The goal should be nodal dispatch of demand resources with no advance notice required as is the case for generation resources.

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

88 *Id.*

89 FERC v. Electric Power Supply Association, Slip Op. No. 14-840.

90 The total credits and MWh numbers for demand resources were calculated as of February 27, 2015 and may change as a result of continued PJM billing updates.

91 Economic credits are synonymous with revenue received for reductions under the economic load response program.

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

## Section 6 Recommendations

The MMU recognizes that PJM has incorporated some of these recommendations in the Capacity Performance filing. The status of each recommendation reflects the status at December 31, 2015.

- The MMU recommends, as a preferred alternative to having PJM demand side programs, that demand response be on the demand side of the markets and that customers be able to avoid capacity and energy charges by not using capacity and energy at their discretion and that customer payments be determined only by metered load. (Priority: High. First reported 2014. Status: Not adopted. )
- The MMU recommends that there be only one demand response product, with an obligation to respond when called for all hours of the year, and that the demand response be on the demand side of the capacity market. (Priority: High. First reported 2011. Status: Partially Adopted.[93])
- The MMU recommends that the option to specify a minimum dispatch price under the Emergency and Pre-Emergency Program Full option be eliminated and that participating resources receive the hourly real-time LMP less any generation component of their retail rate. (Priority: Medium. First reported 2010. Status: Not adopted.)
- The MMU recommends that the emergency load response program be classified as an economic program, responding to economic price signals and not an emergency program responding only after an emergency is called and not triggering the definition of a PJM emergency. (Priority: High. First reported 2012. Status: Not adopted.)
- The MMU 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. (Priority: Low. First reported 2010. Status: Not adopted.)
- The MMU recommends that a daily energy market must offer requirement apply to demand resources, comparable to the rule applicable to generation capacity resources.[94] (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that the lead times for demand resources be shortened to 30 minutes with an hour minimum dispatch for all resources. (Priority: Medium. First reported 2013. Status: Partially adopted.)
- The MMU recommends that demand resources be required to provide their nodal location, comparable to generation resources. (Priority: High. First reported 2011. Status: Not adopted.)
- The MMU recommends that PJM require nodal dispatch of demand resources with no advance notice required or, if nodal location is not required, subzonal dispatch of demand resources with no advance notice required. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM eliminate the measurement of compliance across zones within a compliance aggregation area (CAA). The multiple zone approach is less locational than the zonal and subzonal approach and creates larger mismatches between the locational need for the resources and the actual response. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends capping the baseline for measuring compliance under GLD, for the limited summer product, at the customers' PLC. (Priority: High. First reported 2010. Status: Adopted.)
- The MMU recommends capping the baseline for measuring capacity compliance under winter compliance at the customers' PLC, similar to GLD, to avoid double counting. (Priority: High. First reported 2010. Status: Partially adopted.)
- The MMU recommends that measurement and verification methods for demand resources be modified to reflect compliance more accurately. (Priority: Medium. First reported 2009. Status: Not adopted.)
- The MMU recommends that compliance rules be revised to include submittal of all necessary hourly load data, and that negative values be included when calculating event compliance across hours

93 PJM's Capacity Performance proposal includes this change. See "Reforms to the Reliability Pricing Market ("RPM") and Related Rules in the PJM Open Access Transmission Tariff ("Tariff") and Reliability Assurance Agreement Among Load Serving Entities ("RAA")," Docket No. ER15-632-000 and "PJM Interconnection, L.L.C." Docket No. EL15-29-000.

94 See "Complaint and Motion to Consolidate of the Independent Market Monitor for PJM," Docket No. EL14-20-000 (January 27, 2014) at 1.

and registrations. (Priority: Medium. First reported 2012. Status: Not adopted.)

- The MMU recommends that PJM adopt the ISO-NE five-minute metering requirements in order to ensure that dispatchers have the necessary information for reliability and that market payments to demand resources be calculated based on interval meter data at the site of the demand reductions.[95] (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that demand response event compliance be calculated for each hour and the penalty structure reflect hourly compliance for the base and capacity performance products. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that demand resources whose load drop method is designated as "Other" explicitly record the method of load drop. (Priority: Low. First reported 2013. Status: Adopted, Q2, 2014.)
- The MMU recommends that load management testing be initiated by PJM with limited warning to CSPs in order to more accurately represent the conditions of an emergency event. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends that shutdown cost be defined as the cost to curtail load for a given period that does not vary with the measured reduction or, for behind the meter generators, be the start cost defined in Manual 15 for generators. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends that the Net Benefits Test be eliminated and that demand response resources be paid LMP less any generation component of the applicable retail rate. (Priority: Low. New recommendation. Status: Not adopted.)
- The MMU recommends that the tariff rules for demand response clarify that a resource and its CSP, if any, must notify PJM of material changes affecting the capability of the resource to perform as registered and to terminate registrations that are no longer capable of responding to PJM dispatch directives because load has been reduced or eliminated, such as in the case of bankrupt and/or out of service facilities. (Priority: Medium. First reported Q2, 2015. Status: Not adopted.)

## Section 6 Conclusion

A fully functional demand side of the electricity market means that end use customers or their designated intermediaries will have the ability to see real-time energy price signals in real time, will have the ability to react to real-time prices in real time and will have the ability to receive the direct benefits or costs of changes in real-time energy use. In addition, customers or their designated intermediaries will have the ability to see current capacity prices, will have the ability to react to capacity prices and will have the ability to receive the direct benefits or costs of changes in the demand for capacity in the same year in which demand for capacity changes. 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.

In the energy market, if there is to be a demand side program, demand resources should be paid the value of energy, which is LMP less any generation component of the applicable retail rate. There is no reason to have the net benefits test. The necessity for the net benefits test is an illustration of the illogical approach to demand side compensation embodied in paying full LMP to demand resources. The benefit of demand side resources is not that they suppress market prices, but that customers can choose not to consume at the current price of power, that individual customers benefit from their choices and that the choices of all customers are reflected in market prices. If customers face the market price, customers should have the ability to not purchase power and the market impact of that choice does not require a test for appropriateness.

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

In order to be a substitute for generation, demand resources should be defined in PJM rules as an economic

95 See ISO-NE Tariff, Section III, Market Rule 1, Appendix E1 and Appendix E2, "Demand Response," <http://www.iso-ne.com/regulatory/tariff/sect_3/mr1_append-e.pdf>. (Accessed February 17, 2015) ISO-NE requires that DR have an interval meter with five minute data reported to the ISO and each behind the meter generator is required to have a separate interval meter. After June 1, 2017, demand response resources in ISO-NE must also be registered at a single node.

resource, as generation is defined. Demand resources should be required to offer in the Day-Ahead Energy Market and should be called when the resources are required and prior to the declaration of an emergency. Demand resources should be available for every hour of the year and not be limited to a small number of hours.

In order to be a substitute for generation, demand resources should be subject to robust measurement and verification techniques to ensure that transitional DR programs incent the desired behavior. The methods used in PJM programs today are not adequate to determine and quantify deliberate actions taken to reduce consumption.

In order to be a substitute for generation, demand resources should provide a nodal location and should be dispatched nodally to enhance the effectiveness of demand resources and to permit the efficient functioning of the energy market. Both subzonal and multi-zone compliance should be eliminated because they are inconsistent with an efficient nodal market.

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

In order to be a substitute for generation, reductions should be calculated hourly for dispatched DR. The current rules use the average reduction for the duration of an event. The average reduction across multiple hours does not provide an accurate metric for each hour of the event and is inconsistent with the measurement of generation resources. Measuring compliance hourly would provide accurate information to the PJM system. Under the new CP rules, the performance of demand response during Performance Assessment Hours will be measured on an hourly basis. Overall demand response compliance is still measured by performance across the entire event.[96]

In order to be a substitute for generation, any demand resource and its Curtailment Service Provider (CSP), should be required to notify PJM of material changes affecting the capability of the resource to perform as registered and to terminate registrations that are no longer capable of responding to PJM dispatch directives, such as in the case of bankrupt and out of service facilities. Generation resources are required to inform PJM of any change in availability status, including outages and shutdown status.

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

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

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

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

96 PJM "Manual 18: Capacity Market," Revision 29 (October 16, 2015), p 148.

Customers would pay for capacity and energy depending solely on metered load.

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

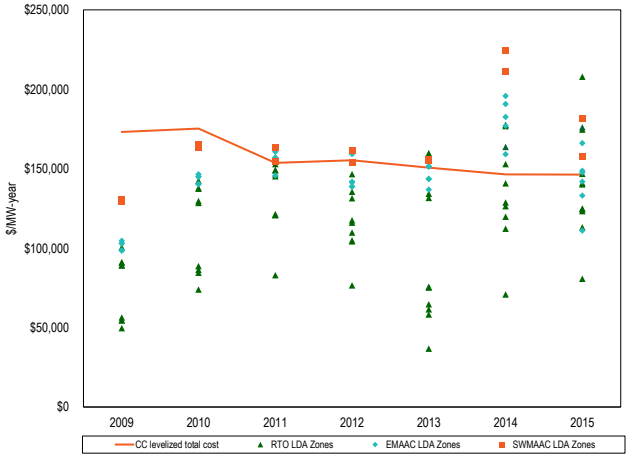
This approach would work under the current RPM design and this approach would work under the CP design. This approach is entirely consistent with the Supreme Court decision in EPSA as it does not depend on whether FERC has jurisdiction over the demand side. This approach will allow FERC to more fully realize its overriding policy objective to create competitive and efficient wholesale energy markets. The decision of the Supreme Court addressed jurisdictional issues and did not address the merits of FERC's approach. The Supreme Court's decision has removed the uncertainty surrounding the jurisdictional issues and created the opportunity for FERC to revisit its approach to demand side.

## Overview: Section 7, "Net Revenue"

### Net Revenue

- Net revenues are significantly affected by fuel prices, energy prices and capacity prices. Coal and natural gas prices and energy prices were lower in 2015 than in 2014. Net revenues from the energy market for all plant types were affected by the lower prices. Capacity prices for calendar year 2015 were higher than in 2014 in the western zones and helped some of the new entrant gas units fully recover levelized total costs.
- In 2015, average energy market net revenues decreased by 23 percent for a new CT, 27 percent for a new CC, 53 percent for a new CP, 59 percent for a new DS, 38 percent for a new nuclear plant, 30 percent for a new wind installation, and 31 percent for a new solar installation. The comparison to 2014 reflects, in part, the very high net revenues in January 2014.
- Capacity revenues for calendar year 2015 increased over 2014 in the western zones and decreased in the eastern zones. Capacity revenue accounted for 49 percent of total net revenues for a new CT, 38 percent for a new CC, 49 percent for a new CP, 81 percent for a new DS, and 6 percent for a new nuclear plant.
- In 2015, a new CT would have received sufficient net revenue to cover levelized total costs in six of the 20 zones and more than 90 percent of levelized total costs in an additional six zones.
- In 2015, a new CC would have received sufficient net revenue to cover levelized total costs in nine of the 20 zones and more than 90 percent of levelized total costs in an additional four zones.

**Figure 11 New entrant CC net revenue and 20-year levelized total cost by LDA (Dollars per installed MW-year): 2009 through 2015**

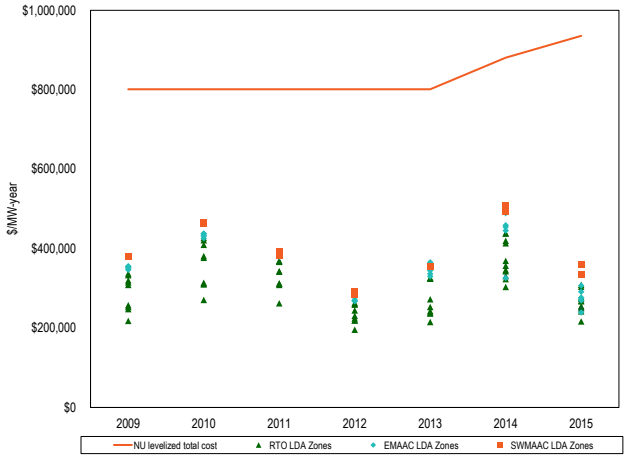



- In 2015, a new CP would not have received sufficient net revenue to cover levelized total costs in any zone.

Figure 12 New entrant CP net revenue and 20-year levelized total cost by LDA (Dollars per installed MW-year): 2009 through 2015


- In 2015, a new nuclear plant would not have received sufficient net revenue to cover levelized total costs in any zone.

Figure 13 New entrant NU net revenue and 20-year levelized total cost by LDA (Dollars per installed MW-year): 2009 through 2015




- In 2015, net revenues covered more than 82 percent of the annual levelized total costs of a new entrant wind installation and 175 percent of the annual levelized total costs of a new entrant solar installation. Production tax credits and renewable energy credits accounted for 47 percent of the total net revenue of a wind installation and 78 percent of the total net revenue of a solar installation.
- In 2015, a substantial portion of units did not achieve full recovery of avoidable costs through net revenue from energy markets alone, illustrating the critical role of the PJM Capacity Market in providing incentives for continued operation and investment. In 2015, RPM capacity revenues were sufficient to cover the shortfall between energy revenues and avoidable costs for the majority of units and technology types in PJM, with the exception of some coal and oil or gas steam units.
- The actual net revenue results show that 28 units with 11,908 MW of capacity in PJM are at risk of retirement in addition to the units that are currently planning to retire. Of the 28 units, 23 are coal units and account for 99 percent of the capacity at risk.

## Section 7 Conclusion

Wholesale electric power markets are affected by externally imposed reliability requirements. A regulatory authority external to the market makes a determination as to the acceptable level of reliability which is enforced through a requirement to maintain a target level of installed or unforced capacity. The requirement to maintain a target level of installed capacity can be enforced via a variety of mechanisms, including government construction of generation, full-requirement contracts with developers to construct and operate generation, state utility commission mandates to construct capacity, or capacity markets of various types. Regardless of the enforcement mechanism, the exogenous requirement to construct capacity in excess of what is constructed in response to energy market signals has an impact on energy markets. The reliability requirement results in maintaining a level of capacity in excess of the level that would result from the operation of an energy market alone. The result of that additional capacity is to reduce the level and volatility of energy market prices and to reduce the duration of high energy market prices. This, in turn, reduces net revenue to generation owners which reduces the incentive to invest. The exact level of both aggregate and locational excess capacity is a function of the calculation methods used by RTOs and ISOs.

# Overview: Section 8, "Environmental and Renewables"

## Federal Environmental Regulation

- **EPA Mercury and Air Toxics Standards Rule.** On December 16, 2011, the U.S. Environmental Protection Agency (EPA) issued its Mercury and Air Toxics Standards rule (MATS), which applies the Clean Air Act (CAA) maximum achievable control technology (MACT) requirement to new or modified sources of emissions of mercury and arsenic, acid gas, nickel, selenium and cyanide.[97] The rule established a compliance deadline of April 16, 2015.

  In a related EPA rule also issued on December 16, 2011, regarding utility New Source Performance Standards (NSPS), the EPA requires new coal and oil fired electric utility generating units constructed after May 3, 2011, to comply with amended emission standards for $SO_2$, $NO_X$ and filterable particulate matter (PM).

  On June 29, 2015, the U.S. Supreme Court remanded MATS to the D.C. Circuit Court and ordered the EPA to consider cost earlier in the process when making the decision whether to regulate power plants under MATS.[98] On December 15, 2015, the D.C. Circuit Court remanded the matter to EPA while keeping the rule effective, noting that the "EPA has represented that it is on track to issue a final finding ... by April 15, 2016."[99]

- **Air Quality Standards ($NO_X$ and $SO_2$ Emissions).** The CAA requires each state to attain and maintain compliance with fine PM and ozone national ambient air quality standards (NAAQS). Much recent regulatory activity concerning emissions has concerned the development and implementation of a transport rule to address the CAA's requirement that each state prohibit emissions that significantly interfere with the ability of another state to meet NAAQS.[100]

  On April 29, 2014, the U.S. Supreme Court upheld EPA's Cross-State Air Pollution Rule (CSAPR) and on October 23, 2014, the U.S. Court of Appeals for the District of Columbia Circuit lifted the stay imposed on CSAPR, clearing the way for the EPA to implement this rule and to replace the Clean Air Interstate Rule (CAIR).[101] [102]

  In the same decision, the U.S. Supreme Court remanded "particularized as-applied challenge[s]" to the EPA's 2014 emissions budgets.[103] On July 28, 2015, on remand, the U.S. Court of Appeals for the District of Columbia Circuit invalidated the 2014 $SO_2$ budgets for a number of states, including PJM states Maryland, New Jersey, North Carolina, Ohio, Pennsylvania, Virginia and West Virginia.[104] The court directed the EPA to reconsider the 2015 emissions budgets for these states based on the actual amount of reduced emissions that states in upwind states needed to attain in order to bring each downwind state into attainment.[105] Under the invalidated approach, the EPA calculated how much pollution each upwind state could eliminate if all of its sources applied pollution control at particular cost thresholds.[106] A new approach likely will significantly reduce the emission budgets (lower emissions levels will be allowed) for the indicated states. The court did not vacate the currently assigned budgets which remain effective until replaced.[107]

  On November 21, 2014, the EPA issued a rule tolling by three years CSAPR's original deadlines. The rule means that compliance with CSAPR's Phase 1 emissions budgets is now required in 2015 and 2016 and CSAPR's Phase 2 emissions in 2017 and beyond.[108]

- **National Emission Standards for Reciprocating Internal Combustion Engines.** On May 1, 2015, the U.S. Court of Appeals for the District of Columbia Circuit reversed the portion of the final rule exempting 100 hours of run time for certain stationary reciprocating internal combustion engines (RICE) participating

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

98 Michigan et al. v. EPA, Slip Op. No. 14-46.

99 White Stallion Energy Center, LLC v EPA, Slip Op. No. 12-1100 (D.C. Cir. 2015) (per curiam).

100 CAA § 110(a)(2)(D)(i)(I).

101 See EPA et al. v. EME Homer City Generation, L.P. et al., 134 S. Ct. 1584 (2014), *reversing* 696 F.3d 7 (D.C. Cir. 2012).

102 See EME Homer City Generation, L.P. v EPA et al., No. 11-1302.

103 134 S. Ct. at 1609.

104 EME Homer City Generation , L.P. v EPA et al., Slip Op. No. 11-1302 (July 28, 2015).

105 *Id.* at 11–12.

106 *Id.* at 11.

107 Emissions Budget Decision at 24–25.

108 *Rulemaking to Amend Dates in Federal Implementation Plans Addressing Interstate Transport of Ozone and Fine Particulate Matter*, EPA-HQ-OAR-2009-0491 (Nov. 21, 2014).

in emergency demand response programs.[109] As a result, the national emissions standards uniformly apply to all RICE.[110] The Court held that "EPA acted arbitrarily and capriciously when it modified the National Emissions Standards and the Performance Standards to allow backup generators to operate without emissions controls for up to 100 hours per year as part of an emergency demand-response program."[111] Specifically, the Court found that the EPA failed to consider arguments concerning the rule's "impact on the efficiency and reliability of the energy grid," including arguments raised by the MMU.[112]

- **Greenhouse Gas Emissions Rule.** On August 3, 2015, the EPA issued a final rule for regulating $CO_2$ from certain existing power generation facilities titled Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units (the Clean Power Plan).[113] The rule requires that individual state plans be submitted by September 6, 2016. However, on February 9, 2016, the U.S. Supreme Court issued a stay on the rule that will prevent its taking effect until judicial review is completed.[114]
- **Cooling Water Intakes.** The EPA has promulgated a rule implementing Section 316(b) of the Clean Water Act (CWA), which requires that cooling water intake structures reflect the best technology available for minimizing adverse environmental impacts.[115] The rule is implemented as National Pollutant Discharge Elimination System (NPDES) permits are issued, with exceptions in certain cases for permits expiring prior to July 14, 2018.
- **Waste Disposal.** On December 19, 2014, EPA issued its Coal Combustion Residuals rule (CCRR), effective October 19, 2015. The CCRR likely will raise the costs of disposal of CCRs to meet the EPA criteria.

## State Environmental Regulation

- **NJ High Electric Demand Day (HEDD) Rule.** New Jersey addressed the issue of $NO_X$ emissions on peak energy demand days with a rule that defines peak energy usage days, referred to as high electric demand days or HEDD, and imposes operational restrictions and emissions control requirements on units responsible for significant $NO_X$ emissions on such high energy demand days.[116] New Jersey's HEDD rule, which became effective May 19, 2009, applies to HEDD units, which include units that have a $NO_X$ emissions rate on HEDD equal to or exceeding 0.15 lbs/MMBtu and lack identified emission control technologies.[117]
- **Illinois Air Quality Standards ($NO_X$, $SO_2$ and Hg).** The State of Illinois has promulgated its own standards for $NO_X$, $SO_2$ and Hg (mercury) known as Multi-Pollutant Standards ("MPS") and Combined Pollutants Standards ("CPS").[118] MPS and CPS establish standards that are more stringent and take effect earlier than comparable Federal regulations, such as the EPA MATS rule.
- **Regional Greenhouse Gas Initiative (RGGI).** The Regional Greenhouse Gas Initiative (RGGI) is a cooperative effort by Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont to cap $CO_2$ emissions from power generation facilities and facilitate trading of emissions allowances. Auction prices in 2015 for the 2015-2017 compliance period were $7.50 per ton. The clearing price is equivalent to a price of $8.27 per metric tonne, the unit used in other carbon markets.

## Emissions Controls in PJM Markets

Environmental regulations affect decisions about emission control investments in existing units, investment in new units and decisions to retire units lacking emission controls. As a result of environmental regulations and agreements to limit emissions, many PJM units burning fossil fuels have installed emission control technology. On December 31, 2015, 76.7 percent of coal steam MW had some type of FGD (flue-gas

109 Delaware Department of Natural Resources and Environmental Control (DENREC) v. EPA, Slip Op. No. 13-1093; National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines; New Source Performance Standards for Stationary Internal Combustion Engines, Final Rule, EPA Docket No. EPA-HQ-OAR-2008-0708, 78 Fed. Reg. 9403 (January 30, 2013).

110 *Id.*

111 DENREC v. EPA at 3, 20–21.

112 *Id.* at 22, citing Comments of the Independent Market Monitor for PJM, EPA Docket No. EPA-HQ-OAR-2008-0708 (August 9, 2012) at 2.

113 *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units*, EPA-HQ-OAR-2013-0602, Final Rule *mimeo* (August 3, 2015), also known as the "Clean Power Plan."

114 North Dakota v. EPA, et al., Order 15A793.

115 See EPA, *National Pollutant Discharge Elimination System—Final Regulations to Establish Requirements for Cooling Water Intake Structures at Existing Facilities and Amend Requirements at Phase I Facilities*, EPA-HQ-OW-2008-0667, 79 Fed. Reg. 48300 (Aug. 15, 2014).

116 N.J.A.C. § 7:27–19.

117 CTs must have either water injection or selective catalytic reduction (SCR) controls; steam units must have either an SCR or selective non-catalytic reduction (SNCR).

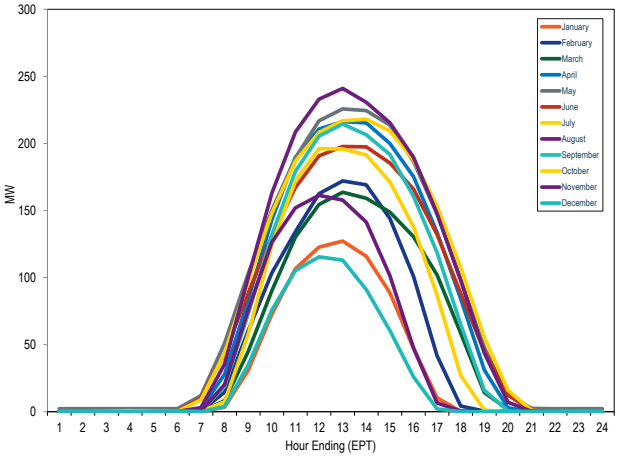
118 35 Ill. Admin. Code §§ 225.233 (Multi-Pollutant Standard (MPS)), 224.295 (Combined Pollutant Standard: Emissions Standards for $NO_X$ and $SO_2$ (CPS)).

desulfurization) technology to reduce $SO_2$ emissions, while 99.5 percent of coal steam MW had some type of particulate control, and 92.8 percent of fossil fuel fired capacity in PJM had $NO_x$ emission control technology.

## State Renewable Portfolio Standards

Many PJM jurisdictions have enacted legislation to require that a defined percentage of retail suppliers' load be served by renewable resources, for which there are many standards and definitions. These are typically known as renewable portfolio standards, or RPS. As of December 31, 2015, Delaware, Illinois, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, and Washington D.C. had renewable portfolio standards. Virginia and Indiana have enacted voluntary renewable portfolio standards. Kentucky and Tennessee have not enacted renewable portfolio standards. Ohio delayed a scheduled increase from 2.5 percent to 3.5 percent in its RPS standards from 2015 until 2017 and removed the 12.5 percent alternative energy requirement. Ohio currently has an ongoing Ohio Energy Mandates Study Committee that is discussing the costs and benefits of the RPS as outlined in Senate Bill 310.[119] West Virginia had a voluntary standard, but the state Legislature repealed the West Virginia renewable portfolio standard on January 22, 2015.

### Figure 14 Average hourly real-time generation of solar units in PJM: 2015




119 See Ohio Senate Bill 310.

## Section 8 Conclusion

Environmental requirements and renewable energy mandates at both the federal and state levels have a significant impact on the cost of energy and capacity in PJM markets. Attempts to extend the definition of renewable energy to include nuclear power in order to provide subsidies to nuclear power could increase this impact if successful. Renewable energy credit markets are markets related to the production and purchase of wholesale power, but FERC has determined that RECs are not regulated under the Federal Power Act unless the REC is sold as part of a transaction that also includes a wholesale sale of electric energy in a bundled transaction.[120]

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

RECs clearly affect prices in the PJM wholesale power market. Some resources are not economic except for the ability to purchase or sell RECs. REC markets are not transparent. Data on REC prices and markets are not publicly available for all PJM states. RECs markets are, as an economic fact, integrated with PJM markets including energy and Capacity markets, but are not formally recognized as part of PJM markets.

PJM markets provide a flexible mechanism for incorporating the costs of environmental controls and meeting environmental requirements in a cost effective manner. Costs for environmental controls are part of bids for capacity resources in the PJM Capacity Market. The costs of emissions credits are included in energy offers. PJM markets also provide a flexible mechanism

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

that incorporates renewable resources and the impacts of renewable energy credit markets, and ensure that renewable resources have access to a broad market. PJM markets provide efficient price signals that permit valuation of resources with very different characteristics when they provide the same product.

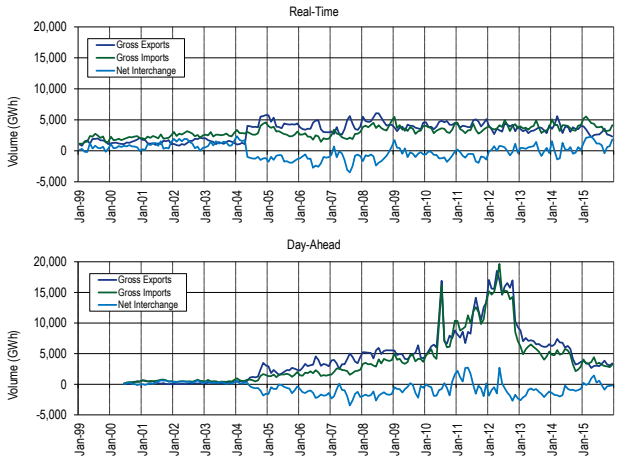
PJM markets could also provide a flexible mechanism for states to comply with the EPA's Clean Power Plan, for example by incorporating a carbon price in unit offers which would be reflected in PJM's economic dispatch. The imposition of specific and prescriptive environmental dispatch rules would, in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

## Overview: Section 9, "Interchange Transactions"

### Interchange Transaction Activity

- **Aggregate Imports and Exports in the Real-Time Energy Market.** In 2015, PJM was a net exporter of energy in the Real-Time Energy Market in September, and a net importer in the remaining 11 months.[121] In 2015, the real-time net interchange of 15,717.4 GWh was higher than net interchange of 1,137.8 GWh in 2014.
- **Aggregate Imports and Exports in the Day-Ahead Energy Market.** In 2015, PJM was a net exporter of energy in the Day-Ahead Energy Market in February, August, September, October, November and December, and a net importer in the remaining six months. In 2015, the total day-ahead net interchange of 1,603.1 GWh was higher than net interchange of -14,305.5 GWh in 2014. The large difference in the day-ahead net interchange totals was a result of the reduction in up to congestion transaction volumes.[122]
- **Aggregate Imports and Exports in the Day-Ahead and the Real-Time Energy Market.** In 2015, gross imports in the Day-Ahead Energy Market were 81.7 percent of gross imports in the Real-Time Energy Market (109.5 percent in 2014). In 2015, gross exports in the Day-Ahead Energy Market were 114.5 percent of the gross exports in the Real-Time Energy Market (143.2 percent in 2014).

**Figure 15 PJM real-time and day-ahead scheduled import and export transaction volume history: 1999 through 2015**




- **Interface Imports and Exports in the Real-Time Energy Market.** In 2015, there were net scheduled exports at eight of PJM's 20 interfaces in the Real-Time Energy Market.
- **Interface Pricing Point Imports and Exports in the Real-Time Energy Market.** In 2015, there were net scheduled exports at 10 of PJM's 18 interface pricing points eligible for real-time transactions in the Real-Time Energy Market.[123]
- **Interface Imports and Exports in the Day-Ahead Energy Market.** In 2015, there were net scheduled exports at eight of PJM's 20 interfaces in the Day-Ahead Energy Market.
- **Interface Pricing Point Imports and Exports in the Day-Ahead Energy Market.** In 2015, there were net scheduled exports at 11 of PJM's 19 interface pricing points eligible for day-ahead transactions in the Day-Ahead Energy Market.
- **Up to Congestion Interface Pricing Point Imports and Exports in the Day-Ahead Energy Market.** In 2015, up to congestion transactions were net exports at five of PJM's 19 interface pricing points eligible for day-ahead transactions in the Day-Ahead Market.
- **Inadvertent Interchange.** In 2015, net scheduled interchange was 15,717 GWh and net actual

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

122 On August 29, 2014, FERC issued an Order which created an obligation for UTCs to pay any uplift determined to be appropriate in the Commission review, effective September 8, 2014. 18 CFR § 385.213

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

interchange was 15,368 GWh, a difference of 349 GWh. In 2014, the difference was 82 GWh. This difference is inadvertent interchange.

- **Loop Flows.** In 2015, the Wisconsin Energy Corporation (WEC) interface had the largest loop flows of any interface with -846 GWh of net scheduled interchange and 9,985 GWh of net actual interchange, a difference of 10,831 GWh. (Table 9-18.) In 2015, the SouthEXP interface pricing point had the largest loop flows of any interface pricing point with -718 GWh of net scheduled interchange and -10,960 GWh of net actual interchange, a difference of 10,242 GWh.

## Interactions with Bordering Areas

### PJM Interface Pricing with Organized Markets

- **PJM and MISO Interface Prices.** In 2015, the direction of the hourly flow was consistent with the real-time hourly price differences between the PJM/MISO Interface and the MISO/PJM Interface in 55.4 percent of the hours.
- **PJM and New York ISO Interface Prices.** In 2015, the direction of the hourly flow was consistent with the real-time hourly price differences between the PJM/NYIS Interface and the NYISO/PJM proxy bus in 58.2 percent of the hours.
- **Neptune Underwater Transmission Line to Long Island, New York.** In 2015, the hourly flow (PJM to NYISO) was consistent with the real-time hourly price differences between the PJM Neptune Interface and the NYISO Neptune bus in 58.2 percent of the hours.
- **Linden Variable Frequency Transformer (VFT) Facility.** In 2015, the hourly flow (PJM to NYISO) was consistent with the real-time hourly price differences between the PJM Linden Interface and the NYISO Linden bus in 53.0 percent of the hours.
- **Hudson DC Line.** In 2015, the hourly flow (PJM to NYISO) was consistent with the real-time hourly price differences between the PJM Hudson Interface and the NYISO Hudson bus in 42.1 percent of the hours.

### Interchange Transaction Issues

- **PJM Transmission Loading Relief Procedures (TLRs).** PJM issued 22 TLRs of level 3a or higher in 2015, compared to eight such TLRs issued in 2014.
- **Up to congestion.** On August 29, 2014, FERC issued an Order which created an obligation for up to congestion transactions to pay any uplift determined to be appropriate in the Commission review, effective September 8, 2014.[124] The average number of up to congestion bids decreased by 42.8 percent and the average cleared volume of up to congestion bids decreased by 61.1 percent in 2015, compared to 2014, but there was an increase in up to congestion volume in December 2015, coincident with the expiration of the fifteen month resettlement period for the proceeding related to uplift charges for UTC transactions.[125]
- **45 Minute Schedule Duration Rule.** Effective May 19, 2014, PJM removed the 45 minute scheduling duration rule in response to FERC Order No. 764.[126] [127] PJM and the MMU issued a statement indicating ongoing concern about market participants' scheduling behavior, and a commitment to address any scheduling behavior that raises operational or market manipulation concerns.[128]

## Section 9 Recommendations

- The MMU recommends that PJM eliminate the IMO interface pricing point, and assign the transactions that originate or sink in the IESO balancing authority to the MISO interface pricing point. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM monitor, and adjust as necessary, the weights applied to the components of the interfaces to ensure that the interface prices reflect ongoing changes in system conditions. The MMU also recommends that PJM review the mappings of external balancing authorities to individual interface pricing points to reflect changes to the impact of the external power source on PJM

124 148 FERC ¶ 61,144 (2014).*Order Instituting Section 206 Proceeding and Establishing Procedures.*

125 16 U.S.C. § 824e.

126 *Integration of Variable Energy Resources*, Order No. 764, 139 FERC ¶ 61,246 (2012), *order on reh'g*, Order No. 764-A, 141 FERC ¶ 61231 (2012).

127 *See* Letter Order, Docket No. ER14-381-000 (June 30, 2014).

128 *See* joint statement of PJM and the MMU re Interchange Scheduling issued July 29, 2014, which can be accessed at: <http://www.pjm.com/~/media/documents/reports/20140729-pjm-imm-joint-statement-on-interchange-scheduling.ashx>.

tie lines as a result of system topology changes. The MMU recommends that this review occur at least annually. (Priority: Low. First reported 2009. Status: Not adopted.)

- The MMU recommends that the submission deadline for real-time dispatchable transactions be modified from 1800 on the day prior, to three hours prior to the requested start time, and that the minimum duration be modified from one hour to 15 minutes. These changes would give PJM a more flexible product that could be used to meet load in the most economic manner. (Priority: Medium. First reported Q3 2014. Status: Adopted partially, Q1 2015.)
- The MMU recommends that PJM explore an interchange optimization solution with its neighboring balancing authorities that would remove the need for market participants to schedule physical transactions across seams. Such a solution would include an optimized, but limited, joint dispatch approach that uses supply curves and treats seams between balancing authorities as constraints, similar to other constraints within an LMP market. (Priority: Medium. First reported 2014. Status: Not adopted.)
- The MMU recommends that PJM permit unlimited spot market imports as well as unlimited non-firm point-to-point willing to pay congestion imports and exports at all PJM interfaces in order to improve the efficiency of the market. (Priority: Medium. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM implement a validation method for submitted transactions that would prohibit market participants from breaking transactions into smaller segments to defeat the interface pricing rule by concealing the true source or sink of the transaction. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM implement a validation method for submitted transactions that would require market participants to submit transactions on market paths that reflect the expected actual power flow in order to reduce unscheduled loop flows. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM implement rules to prevent sham scheduling. The MMU's proposed validation rules would address sham scheduling. (Priority: High. First reported 2012. Status: Not adopted. Stakeholder process.)
- The MMU 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. (Priority: Medium. First reported 2003. Status: Not adopted.)
- The MMU recommends that PJM implement additional business rules to remove the incentive to engage in sham scheduling activities using the PJM/IMO interface price. (Priority: Medium. First reported 2014. Status: Not adopted. Stakeholder process.)
- The MMU recommends that PJM eliminate the NIPSCO, Southeast and Southwest interface pricing points from the Day-Ahead and Real-Time Energy Markets and, with VACAR, assign the transactions created under the reserve sharing agreement to the SouthIMP/EXP pricing point. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM immediately provide the required 12-month notice to Duke Energy Progress (DEP) to unilaterally terminate the Joint Operating Agreement. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM and MISO work together to align interface pricing definitions, using the same number of external buses and selecting buses in close proximity on either side of the border with comparable bus weights. (Priority: Medium. First reported 2012. Status: Adopted partially, Q4 2013.)
- The MMU recommends that PJMSettlement Inc. immediately request a credit evaluation from all companies that engaged in up to congestion transactions between September 8, 2014, and December 31, 2015. If PJM has the authority, PJM should ensure that the potential exposure to uplift for that period be included as a contingency in the companies' calculations for credit levels and/or collateral requirements. If PJM does not have the authority to take such steps, PJM should request guidance from FERC. (Priority: High. New recommendation. Status: Not adopted.)

- The MMU recommends that the emergency interchange cap be replaced with a market based solution. (Priority: Low. New recommendation. Status: Not adopted.)

### Section 9 Conclusion

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

The MMU's recommendations related to transactions with external balancing authorities all share the goal of improving the economic efficiency of interchange transactions. The standard of comparison is an LMP market. In an LMP market, redispatch based on LMP and competitive generator offers results in an efficient dispatch and efficient prices. The goal of designing interface transaction rules should be to match the outcome that would exist in an LMP market.

## Overview: Section 10, "Ancillary Services"

### Primary Reserve

PJM's primary reserves are made up of resources, both synchronized and non-synchronized, that can provide energy within ten minutes. Primary reserve is PJM's implementation of the NERC 15-minute contingency reserve requirement.[129]

### Market Structure

- **Supply.** Primary reserve is satisfied by both synchronized reserve (generation or demand response currently synchronized to the grid and available within ten minutes), and non-synchronized reserve (generation currently off-line but available to start and provide energy within ten minutes).
- **Demand.** The PJM primary reserve requirement is 150 percent of the largest contingency. The primary reserve requirement in the RTO Zone was raised on January 8, 2015, to 2,175 MW of which at least 1,700 MW must be available within the Mid-Atlantic Dominion (MAD) Subzone. Adjustments to the primary reserve requirement can occur when grid maintenance or outages change the largest contingency. The actual demand for primary reserve in the RTO Zone in 2015 was 2,210.3 MW. The actual demand for primary reserve in the MAD Subzone in 2015 was 1,713.3 MW.

### Tier 1 Synchronized Reserve

Synchronized reserve is energy or demand reduction synchronized to the grid and capable of increasing output or decreasing load within ten minutes. Synchronized reserve is of two distinct types, tier 1 and tier 2.

Tier 1 synchronized reserve is part of primary reserve and is the capability of on-line resources following economic dispatch to ramp up in ten minutes from their current output in response to a synchronized reserve event. There is no formal market for tier 1 synchronized reserve.

- **Supply.** No offers are made for tier 1 synchronized reserve. The market solution estimates tier 1 synchronized reserve as available 10-minute ramp from the energy dispatch. In 2015, there was an average hourly supply of 1,363.9 MW of tier 1 for the RTO Synchronized Reserve Zone, and an average hourly supply of 1,159.6 MW of tier 1 in the Mid-Atlantic Dominion Subzone.
- **Demand.** The default hourly required synchronized reserve requirement is 1,450 MW in the RTO Reserve Zone and 1,450 MW for the Mid-Atlantic Dominion Reserve Subzone. The requirement can be met with tier 1 or tier 2 synchronized reserves.
- **Tier 1 Synchronized Reserve Event Response.** Tier 1 synchronized reserve is paid when a synchronized reserve event occurs and it responds. When a synchronized reserve event is called, all tier 1 response is paid the average of five-minute LMPs during the event, rather than hourly integrated LMP, plus $50/MW. This is the Synchronized Energy

129 See PJM. "Manual 10: Pre-Scheduling Operations," Revision. 33 (December 22, 2015), p. 24.

Premium Price. The synchronized reserve event response credits for tier 1 response are independent of the tier 2 synchronized reserve market clearing price and independent of the non-synchronized reserve market clearing price.

Of tier 1 synchronized reserve estimated at market clearing, 65.7 percent actually responded during the seven distinct synchronized reserve events longer than ten minutes in 2015. PJM made changes to the way it calculated tier 1 MW for settlements beginning in July 2014. These changes improved the reported response rate by reducing the initial tier 1 estimate.

- **Issues.** The competitive offer for tier 1 synchronized reserves is zero, as there is no incremental cost associated with the ability to ramp up from the current economic dispatch point and the appropriate payment for responding to an event is the five-minute LMP plus $50 per MWh. A tariff change included in the shortage pricing tariff changes (October 1, 2012) added the requirement to pay tier 1 synchronized reserve the tier 2 synchronized reserve market clearing price whenever the non-synchronized reserve market clearing price rises above zero.

  The rationale for this change was and is unclear, but it has had a significant impact on the cost of tier 1 synchronized reserves, resulting in a windfall payment of $10,406,363 to tier 1 resources in 2014, and $34,135,671 in 2015.

## Tier 2 Synchronized Reserve Market

Tier 2 synchronized reserve is part of primary reserve and is comprised of resources that are synchronized to the grid, that incur costs to be synchronized, that have an obligation to respond with corresponding penalties, and that must be dispatched in order to satisfy the synchronized reserve requirement.

When the synchronized reserve requirement cannot be met with tier 1 synchronized reserve, PJM conducts a market to satisfy the balance of the requirement with tier 2 synchronized reserve. The Tier 2 Synchronized Reserve Market includes the PJM RTO Reserve Zone and a subzone, the Mid-Atlantic Dominion Reserve Subzone (MAD).

### Market Structure

- **Supply.** In 2015, the supply of offered and eligible synchronized reserve was 8,549 MW in the RTO Zone of which 3,114 MW (including DSR) was available to the MAD Subzone. This was sufficient to cover the requirement in both the RTO Reserve Zone and the Mid-Atlantic Dominion Reserve Subzone.
- **Demand.** The default hourly required synchronized reserve requirement was 1,450 MW in the RTO Reserve Zone and 1,450 MW for the Mid-Atlantic Dominion Reserve Subzone. The requirement can be met with tier 1 or tier 2 synchronized reserves.
- **Market Concentration.** In 2015, the weighted average HHI for cleared tier 2 synchronized reserve in the Mid-Atlantic Dominion Subzone was 5436 which is classified as highly concentrated. The MMU calculates that 55.7 percent of hours would have failed a three pivotal supplier test in the Mid-Atlantic Dominion Subzone.

  In 2015, the weighted average HHI for cleared tier 2 synchronized reserve in the RTO Synchronized Reserve Zone was 4617 which is classified as highly concentrated. The MMU calculates that 40.2 percent of hours would have failed a three pivotal supplier test in the RTO Synchronized Reserve Zone.

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

### Market Conduct

- **Offers.** There is a must offer requirement for tier 2 synchronized reserve. All non-emergency generation capacity resources are required to submit a daily offer for tier 2 synchronized reserve. Tier 2 synchronized reserve offers from generating units are subject to an offer cap of marginal cost plus $7.50 per MW, plus opportunity cost, which is calculated by PJM.

### Market Performance

- **Price.** The weighted average price for tier 2 synchronized reserve for all cleared hours in the Mid-Atlantic Dominion (MAD) Subzone was $10.12 per MW in 2015, a decrease of $5.38, 34.7 percent from 2014.

The weighted average price for tier 2 synchronized reserve for all cleared hours in the RTO Synchronized Reserve Zone was $11.88 per MW in 2015, a decrease of $1.06, 8.2 percent from 2014.

## Non-Synchronized Reserve Market

Non-synchronized reserve is part of primary reserve and includes the RTO Reserve Zone and the Mid-Atlantic Dominion Reserve Subzone (MAD). Non-synchronized reserve is comprised of non-emergency energy resources not currently synchronized to the grid that can provide energy within ten minutes. Non-synchronized reserve is available to fill the primary reserve requirement above the synchronized reserve requirement. There is no formal market for non-synchronized reserve.

### Market Structure

- **Supply.** In 2015, the supply of eligible non-synchronized reserve was 2,550.1 MW in the RTO Zone and 1,860.8 MW in MAD Subzone.[130]
- **Demand.** Demand for non-synchronized reserve is the remaining primary reserve requirement after tier 1 synchronized reserve is estimated and tier 2 synchronized reserve is scheduled. In the RTO Zone, the market cleared an hourly average of 345.1 MW of non-synchronized reserve in 2015. In the MAD Subzone, the market cleared an hourly average of 390.3 MW of non-synchronized reserve.
- **Market Concentration.** In 2015, the weighted average HHI for cleared non-synchronized reserve in the Mid-Atlantic Dominion Subzone was 4133 which is classified as highly concentrated. In the RTO Zone the weighted average HHI was 4533 which is also highly concentrated. The MMU calculates that 95.1 percent of hours would have failed a three pivotal supplier test in the Mid-Atlantic Dominion Subzone and 68.0 hours would have failed a three pivotal supplier test in the RTO Zone.

### Market Conduct

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

### Market Performance

- **Price.** The non-synchronized reserve price is determined by the opportunity cost of the marginal non-synchronized reserve unit. The non-synchronized reserve weighted average price for all cleared hours in the RTO Reserve Zone was $1.15 per MW in 2015 and in 87.9 percent of hours the market clearing price was $0. The non-synchronized reserve weighted average price for all cleared hours in the Mid-Atlantic Dominion (MAD) Subzone was $1.03 and in 87.6 percent of hours the market clearing price was $0.

## Secondary Reserve (Day-Ahead Scheduling Reserve)

PJM maintains a day-ahead, offer-based market for 30-minute secondary reserve, designed to provide price signals to encourage resources to provide 30-minute reserve.[131] The DASR Market has no performance obligations.

### Market Structure

- **Supply.** The DASR Market is a must offer market. Any resources that do not make an offer have their offer set to $0 per MW. DASR is calculated by the day-ahead market solution as the lesser of the thirty minute energy ramp rate or the emergency maximum MW minus the day-ahead dispatch point for all on-line units. In 2015, the average available hourly DASR was 36,396.0 MW.
- **Demand.** The DASR requirement in 2015 was 5.93 percent of peak load forecast, down from 6.27 percent in 2014. The average DASR MW purchased was 6,245.0 MW per hour 2015.
- **Concentration.** In 2015, the DASR Market would have failed a three pivotal supplier test in 4.1 percent of hours.

### Market Conduct

- **Withholding.** Economic withholding remains an issue in the DASR Market. The direct marginal cost of providing DASR is zero. All offers greater than

130 See PJM. "Manual 11; Energy & Ancillary Services Markets," Revision 79 (December 17, 2015), p. 81. "Because Synchronized Reserve may be utilized to meet the Primary Reserve requirement, there is no explicit requirement for non-synchronized reserves."

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

zero constitute economic withholding. In 2015 a daily average of 37.9 percent of units offered above $0. In 2015 a daily average of 11.6 percent of units offered above $5.

- **DR.** Demand resources are eligible to participate in the DASR Market. Six demand resources have entered offers for DASR.

## Market Performance

- **Price.** The weighted average DASR market clearing price for all cleared hours in 2015 was $2.99 per MW, an increase from $0.63 per MW in 2014.

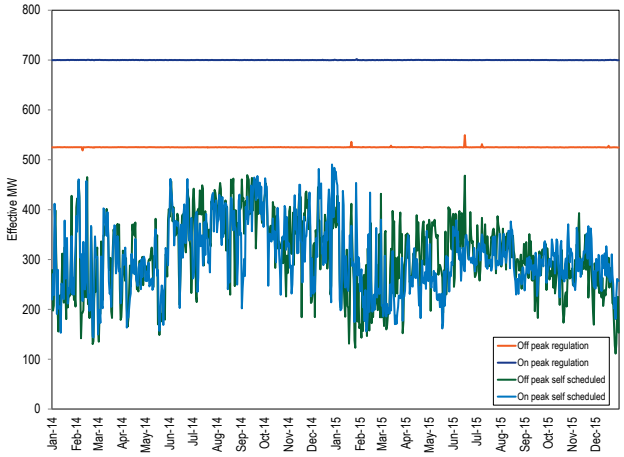
## Regulation Market

The PJM Regulation Market is a real-time market. Regulation is provided by generation resources and demand response resources that qualify to follow a regulation signal (RegA or RegD). PJM jointly optimizes regulation with synchronized reserve and energy to provide all three services at least cost. The PJM regulation market design includes three clearing price components: capability; performance; and lost opportunity cost. The marginal benefit factor and performance score translate a resource's capability in actual MW into effective MW.

## Market Structure

- **Supply.** In 2015, the average hourly eligible supply of regulation was 1,157.8 actual MW (889.9 effective MW). This is a decrease of 122.5 actual MW (27.5 effective MW) from the same period of 2014, when the average hourly eligible supply of regulation was 1,280.3 actual MW (917.4 effective MW).
- **Demand.** The average hourly regulation demand was 640.9 actual MW (663.7 effective MW) in 2015. This is a decrease of 19.8 actual MW (0 effective MW) in the average hourly regulation demand of 660.7 actual MW (663.7 effective MW) from the same period of 2014.
- **Supply and Demand.** The ratio of the average hourly eligible supply of regulation to average hourly regulation demand required was 1.81. This is a 6.70 percent decrease from the same period of 2014 when the ratio was 1.94.
- **Market Concentration.** In 2015, the weighted average (HHI) was 1358 which is classified as moderately concentrated. In 2015, the three pivotal supplier test was failed in 97.8 percent of hours.

**Figure 16 Off peak and on peak regulation levels: 2014 through 2015**




## Market Conduct

- **Offers.** Daily regulation offer prices are submitted for each unit by the unit owner. Owners are required to submit a cost-based offer and may submit a price-based offer. Offers include both a capability offer and a performance offer. Owners must specify which signal type the unit will be following, RegA or RegD.[132] In 2015, there were 291 resources following the RegA signal and 57 resources following the RegD signal.

## Market Performance

- **Price and Cost.** The weighted average clearing price for regulation was $31.92 per effective MW of regulation in 2015, a decrease of $12.55 per MW, or 28.2 percent, from the same period of 2014. The cost of regulation in 2015 was $38.36 per effective MW of regulation, a decrease of $15.46 per MW, or 28.7 percent, from the same period of 2014. The decreases in regulation price and regulation cost resulted primarily from high energy prices in 2014, particularly in January.
- **RMCP Credits.** RegD resources continue to be incorrectly compensated relative to RegA resources due to an inconsistent application of the marginal benefit factor in the optimization, assignment, pricing, and settlement processes. If the Regulation Market were functioning efficiently, RegD and

132 See the *2015 State of the Market Report for PJM*, Volume II, Appendix F "Ancillary Services Markets."

RegA resources would be paid the same price per effective MW.

- **Marginal Benefit Factor Function.** The marginal benefit factor (MBF) measures the substitutability of RegD resources for RegA resources. The marginal benefit factor function is incorrectly applied in the market clearing and incorrectly describes the operational relationship between RegA and RegD.
- **Interim changes to the MBF function.** On December 14, 2015, PJM changed the MBF curve. The modification to the marginal benefit curve did not correct the identified issues with the optimization engine.

## Black Start Service

Black start service is required for the reliable restoration of the grid following a blackout. Black start service is the ability of a generating unit to start without an outside electrical supply, or is the demonstrated ability of a generating unit to automatically remain operating at reduced levels when disconnected from the grid (automatic load rejection or ALR).[133]

In 2015, total black start charges were $53.6 million with $48.4 million in revenue requirement charges and $5.2 million in operating reserve charges. Black start revenue requirements for black start units consist of fixed black start service costs, variable black start service costs, training costs, fuel storage costs, and an incentive factor. Black start operating reserve charges are paid to units scheduled in the Day-Ahead Energy Market or committed in real time to provide black start service under the ALR option or for black start testing. Black start zonal charges in 2015 ranged from $0.04 per MW-day in the PPL Zone (total charges were $118,541) to $3.81 per MW-day in the BGE Zone (total charges were $9,277,796).

## Reactive

Reactive service, reactive supply and voltage control are provided by generation and other sources of reactive power (measured in VAR). Reactive power helps maintain appropriate voltages on the transmission system and is essential to the flow of real power (measured in MW).

In 2015, total reactive service charges were $289.0 million, a 6.1 percent decrease from $307.7 million in 2014. Revenue requirement charges decreased from $281.2 million to $278.4 million and operating reserve charges fell from $26.5 million to $10.7 million. Total charges in 2015 ranged from $2,488 in the RECO Zone to $38.5 million in the AEP Zone. Reactive service revenue requirements are based on FERC approved filings. Reactive service operating reserve charges are paid for scheduling in the Day-Ahead Energy Market and committing in real time units that provide reactive service.

## Section 10 Recommendations

- The MMU recommends that the Regulation Market be modified to incorporate a consistent application of the marginal benefit factor throughout the optimization, assignment and settlement process. (Priority: High. First reported 2012. Status: Not adopted.)
- 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 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. (Priority: Medium. First reported 2010. Status: Partially adopted in 2012.)
- The MMU recommends that the lost opportunity cost in the ancillary services markets be calculated using the schedule on which the unit was scheduled to run in the energy market. (Priority: High. First reported 2010. Status: Partially Adopted.)
- The MMU recommends that the single clearing price for synchronized reserves be determined based on the actual LMP and not the forecast LMP. (Priority: Low. First reported 2010. Status: Adopted.)
- The MMU recommends that the rule requiring the payment of tier 1 synchronized reserve resources when the non-synchronized reserve price is above zero be eliminated immediately. (Priority: High. First reported 2013. Status: Not adopted. Stakeholder process.)

133 OATT Schedule 1 § 1.3BB.

- The MMU recommends that no payments be made to tier 1 resources if they are deselected in the PJM market solution. The MMU also recommends that documentation of the Tier 1 synchronized reserve deselection process be published. (Priority: High. First reported Q3, 2014. Status: Adopted July 2014.)
- The MMU recommends that the tier 2 synchronized reserve must offer requirement be enforced. The MMU recommends that PJM define a set of acceptable reasons why a unit can be made unavailable daily or hourly and require operators to select a reason in eMkt whenever making a unit unavailable. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM be explicit about why tier 1 biasing is used in the Tier 2 Synchronized Reserve Market. The MMU recommends that PJM define explicit rules for the use of tier 1 biasing during any phase of the market solution and identify the relevant rule for each instance of biasing. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM replace the DASR Market with a real-time secondary reserve product that is available and dispatchable in real time. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM revise the current confidentiality rules in order to specifically allow a more transparent disclosure of information regarding black start resources and their associated payments in PJM. (Priority: Low. First reported 2013. Status: Partially adopted, 2014.)
- The MMU recommends that the three pivotal supplier test and market power mitigation be incorporated in the DASR Market. (Priority: Low. First reported 2009. Status: Not adopted.)
- The MMU recommends that a reason code be attached to every hour in which PJM market operations adds additional DASR MW. (Priority: Medium. First reported Q2, 2015. Status: not adopted.)

## Section 10 Conclusion

While the design of the Regulation Market was significantly improved with changes introduced October 1, 2012, a number of issues remain. The market results continue to include the incorrect definition of opportunity cost. The market design has failed to correctly incorporate the marginal benefit factor in optimization, pricing and settlement. The market design uses the marginal benefit factor in the optimization and pricing, but a mileage ratio in settlement. This failure to correctly incorporate marginal benefit factor into the regulation market design has resulted in both underpayment and overpayment of RegD resources and in the over procurement of RegD resources in some hours. These issues have led to the MMU's conclusion that the regulation market design is flawed.

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

The rule that requires payment of the tier 2 synchronized reserve price to tier 1 synchronized reserve resources when the non-synchronized reserve price is greater than zero, is inefficient and results in a substantial windfall payment to the holders of tier 1 synchronized reserve resources. Such tier 1 resources have no obligation to perform and pay no penalties if they do not perform. Tier 1 resources are paid for their response if they do respond. Such resources are not tier 2 resources, although they have the option to offer as tier 2, to take on tier 2 obligations and to be paid as tier 2. If tier 1 resources wish to be paid as tier 2 resources, that option is available. Application of this rule added $10.4 million to the cost of primary reserve in 2014 and $34.1 million to the cost of primary reserve in 2015.

The benefits of markets are realized under these approaches to ancillary service markets. Even in the presence of structurally noncompetitive markets, there can be transparent, market clearing prices based on competitive offers that account explicitly and accurately for opportunity cost. This is consistent with the market design goal of ensuring competitive outcomes that provide appropriate incentives without reliance on the exercise of market power and with explicit mechanisms to prevent the exercise of market power.

The MMU concludes that the regulation market results were competitive. The MMU concludes that the synchronized reserve market results were competitive. The MMU concludes that the DASR market results were competitive, although there is concern about offers above the competitive level affecting prices.

## Overview: Section 11, "Congestion and Marginal Losses"

### Congestion Cost

- **Total Congestion.** Total congestion costs decreased by $546.9 million or 28.3 percent, from $1,932.2 million in 2014 to $1,385.3 million in 2015.

**Table 12 Total PJM congestion (Dollars (Millions)): 2008 through 2015**

| | Congestion Costs (Millions) | | | |
|---|---|---|---|---|
| | Congestion Cost | Percent Change | Total PJM Billing | Percent of PJM Billing |
| 2008 | $2,052 | NA | $34,306 | 6.0% |
| 2009 | $719 | (65.0%) | $26,550 | 2.7% |
| 2010 | $1,423 | 98.0% | $34,771 | 4.1% |
| 2011 | $999 | (29.8%) | $35,887 | 2.8% |
| 2012 | $529 | (47.0%) | $29,181 | 1.8% |
| 2013 | $677 | 28.0% | $33,862 | 2.0% |
| 2014 | $1,932 | 185.5% | $50,030 | 3.9% |
| 2015 | $1,385 | (28.3%) | $42,630 | 3.2% |

- **Day-Ahead Congestion.** Day-ahead congestion costs decreased by $599.1 million or 26.9 percent, from $2,231.3 million in 2014 to $1,632.1 million in 2015.
- **Balancing Congestion.** Balancing congestion costs increased by $52.2 million or 17.5 percent, from -$299.1 million in 2014 to -$246.9 million in 2015.
- **Real-Time Congestion.** Real-time congestion costs decreased by $668.2 million or 30.7 percent, from $2,173.0 million in 2014 to $1,504.9 million in 2015.
- **Monthly Congestion.** In 2015, 31.0 percent ($429.8 million) of total congestion cost was incurred in February and 14.6 percent ($201.9 million) of total congestion cost was incurred in the months of January and March. Monthly total congestion costs in 2015 ranged from $58.4 million in August to $429.8 million in February.
- **Geographic Differences in CLMP.** Differences in CLMP among eastern, southern and western control zones in PJM were primarily a result of congestion on the 5004/5005 Interface, the Bedington - Black Oak Interface, the Bagley – Graceton Line, the Conastone – Northwest Line and the Cherry Valley Flowgate.
- **Congestion Frequency.** Congestion frequency continued to be significantly higher in the Day-Ahead Energy Market than in the Real-Time Energy Market in 2015. The number of congestion event hours in the Day-Ahead Energy Market was about six times higher than the number of congestion event hours in the Real-Time Energy Market.

  Day-ahead congestion frequency decreased by 49.2 percent from 363,463 congestion event hours 2014 to 184,713 congestion event hours in 2015. The day-ahead congestion event hours decreased significantly after September 8, 2014. The reduction was the result of the reduction in up to congestion (UTC) activity which was a result of FERC's UTC uplift refund notice, retroactive to September 8, 2014.

  Real-time congestion frequency decreased by 1.0 percent from 28,802 congestion event hours in 2014 to 28,524 congestion event hours in 2015.
- **Congested Facilities.** Day-ahead, congestion-event hours decreased on all types of congestion facilities. Real-time, congestion-event hours increased on line and transformer facilities and decrease on flowgate and interface facilities.

  The Conastone – Northwest Line was the largest contributor to congestion costs in 2015. With $108.8 million in total congestion costs, it accounted for 7.9 percent of the total PJM congestion costs in 2015.
- **Zonal Congestion.** ComEd had the largest total congestion costs among all control zones in 2015. ComEd had $311.3 million in total congestion

costs, comprised of -$688.9 million in total load congestion payments, -$1,029.4 million in total generation congestion credits and -$29.2 million in explicit congestion costs. The Cherry Valley Flowgate, the Oak Grove - Galesburg Flowgate, the Braidwood - East Frankfort Line, the Bunsonville - Eugene Flowgate and the Rising Flowgate contributed $150.4 million, or 48.3 percent of the total ComEd control zone congestion costs.

- **Ownership.** In 2015, financial entities as a group were net recipients of congestion credits and physical entities were net payers of congestion charges. Explicit costs are the primary source of congestion credits to financial entities. In 2015, financial entities received $133.1 million in congestion credits, a decrease of $93.6 million or 41.3 percent compared to the 2014. In 2015, physical entities paid $1,518.3 million in congestion charges, a decrease of $640.6 million or 29.7 percent compared to 2014. UTCs are in the explicit congestion cost category and comprise most of that category. The total explicit cost is equal to day-ahead explicit cost plus balancing explicit cost. In 2015, the total explicit cost is -$127.3 million and 122.4 percent of the total explicit cost is comprised of congestion cost by UTCs, which is -$155.9 million.

## Marginal Loss Cost

- **Total Marginal Loss Costs.** Total marginal loss costs decreased by $497.4 million or 33.9 percent, from $1,466.1 million in 2014 to $968.7 million in 2015. Total marginal loss costs were higher in 2014 as a result of high load and outages caused by cold weather in January 2014. The loss MWh in PJM decreased 5.3 percent, from 17,150.0 GWh in 2014 to 16,241.3 GWh in 2015. The loss component of LMP remained constant, $0.02 in 2014 and $0.02 in 2015.
- **Monthly Total Marginal Loss Costs.** Monthly total marginal loss costs in 2015 ranged from $44.6 million in December to $220.3 million in February.
- **Day-Ahead Marginal Loss Costs.** Day-ahead marginal loss costs decreased by $558.8 million or 35.6 percent, from $1,571.4 million in 2014 to $1,012.6 million in 2015.
- **Balancing Marginal Loss Costs.** Balancing marginal loss costs increased by $61.4 million or 58.3 percent, from -$105.3 million in 2014 to -$43.9 million in 2015.
- **Total Marginal Loss Surplus.** The total marginal loss surplus decreased in 2015 by $145.8 million or 30.2 percent, from $482.1 million in 2014, to $336.3 million in 2015.

## Energy Cost

- **Total Energy Costs.** Total energy costs increased by $350.3 million or 35.8 percent, from -$977.7 million in 2014 to -$627.4 million in 2015.
- **Day-Ahead Energy Costs.** Day-ahead energy costs increased by $585.8 million or 43.6 percent, from -$1,343.7 million in 2014 to -$757.9 million in 2015.
- **Balancing Energy Costs.** Balancing energy costs decreased by $242.4 million or 65.5 percent, from $370.2 million in 2014 to $127.8 million in 2015.
- **Monthly Total Energy Costs.** Monthly total energy costs in 2015 ranged from -$141.5 million in February to -$28.9 million in December.

## Section 11 Conclusion

Congestion, as defined, is the total congestion payments by load in excess of the total congestion credits received by generation. The level and distribution of congestion reflects the underlying characteristics of the power system, including the nature and capability of transmission facilities, the offers and geographic distribution of generation facilities, the level and geographic distribution of incremental bids and offers and the geographic and temporal distribution of load.

The current ARR/FTR design does not serve as an efficient way to ensure that load receives all the congestion revenues or has the ability to receive the auction revenues associated with all the potential congestion revenues. Total ARR and self scheduled FTR revenue offset only 63.8 percent of total congestion costs including congestion in the Day-Ahead Energy Market and the balancing energy market for the 2014 to 2015 planning period. For the first seven months of the 2015 to 2016 planning period ARRs and self scheduled FTRs offset 85.8 percent of total congestion costs.

ARRs and FTRs served as an effective, but not total, offset to congestion. ARR and FTR revenues offset 88.3

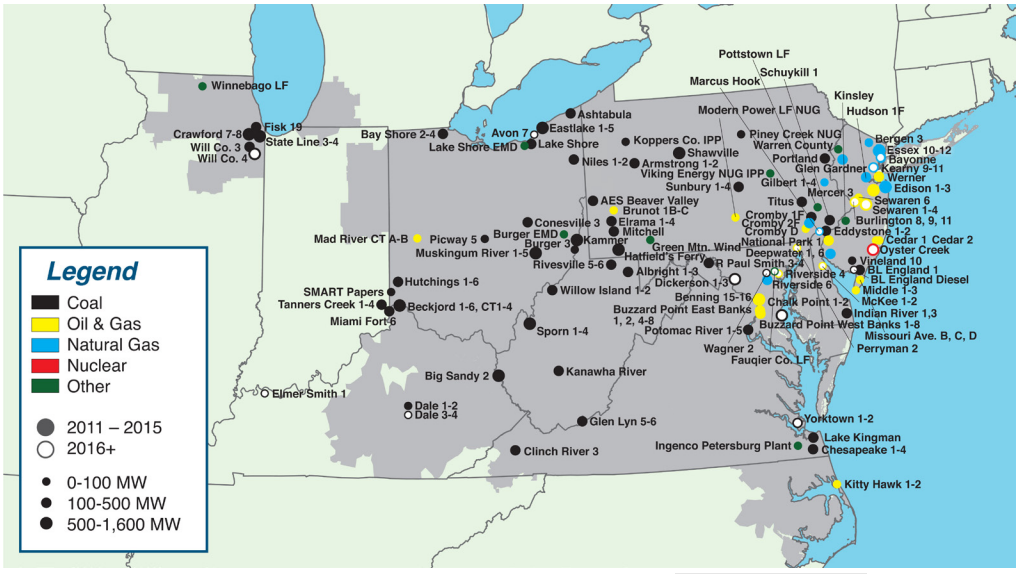
percent of the total congestion costs including the Day-Ahead Energy Market and the balancing energy market in PJM for the 2014 to 2015 planning period. In the first seven months of the 2015 to 2016 planning period (June through December), total ARR and FTR revenues offset 88.7 percent of the congestion costs.

## Overview: Section 12, "Planning"

### Planned Generation and Retirements

- **Planned Generation.** As of December 31, 2015, 85,323.1 MW of capacity were in generation request queues for construction through 2024, compared to an average installed capacity of 187,744.2 MW as of December 31, 2015. Of the capacity in queues, 6,246.5 MW, or 7.3 percent, are uprates and the rest are new generation. Wind projects account for 15,698.8 MW of nameplate capacity or 18.4 percent of the capacity in the queues. Combined-cycle projects account for 56,827.9 MW of capacity or 66.6 percent of the capacity in the queues.
- **Generation Retirements.** As shown in Table 12-6, 27,689.0 MW have been, or are planned to be, retired between 2011 and 2020. Of that, 3,912.3 MW are planned to retire after 2015. In 2015, 9,859.7 MW were retired, of which 7,661.8 MW were coal units. The coal unit retirements were a result of low gas prices and the EPA's Mercury and Air Toxics Standards (MATS) for some units.

Figure 17 Map of PJM unit retirements: 2011 through 2020




### Generation and Transmission Interconnection Planning Process

- Any entity that requests interconnection of a new generating facility, including increases to the capacity of an existing generating unit, or that requests interconnection of a merchant transmission facility, must follow the process defined in the PJM tariff to obtain interconnection service.[134] The process is complex and time consuming at least in part as a result of the required analyses. The cost, time and uncertainty associated with interconnecting to the grid may create barriers to entry for potential entrants.
- The queue contains a substantial number of projects that are not likely to be built. Excluding currently active projects and projects currently under construction, 2,275 projects, representing 327,280.0 MW, have completed the queue process since its inception. Of those, 605 projects, 41,021.9 MW,
- **Generation Mix.** A significant shift in the distribution of unit types within the PJM footprint continues as natural gas fired units enter the queue and steam units retire. While only 2,007.0 MW of coal fired steam capacity are currently in the queue, 60,717.7 MW of gas fired capacity are in the queue. The replacement of coal steam units by units burning natural gas could significantly affect future congestion, the role of firm and interruptible gas supply, and natural gas supply infrastructure.

134 See PJM, OATT Parts IV & VI.

went into service. Of the projects that entered the queue process, 87.5 percent of the MW withdrew prior to completion. Such projects may create barriers to entry for projects that would otherwise be completed by taking up queue positions, increasing interconnection costs and creating uncertainty.

- Feasibility, impact and facilities studies may be delayed for reasons including disputes with developers, circuit and network issues and retooling as a result of projects being withdrawn. The Earlier Queue Submittal Task Force (EQSTF) was established in August 2015 to address delays.[135]
- As defined in the tariff, a transmission owner (TO) is an "entity that owns, leases or otherwise has a possessory interest in facilities used for the transmission of electric energy in interstate commerce under the tariff."[136] Where the transmission owner is a vertically integrated company that also owns generation, there is a potential conflict of interest when the transmission owner evaluates the interconnection requirements of new generation which is a competitor to the generation of the parent company and when the transmission owner evaluates the interconnection requirements of new generation which is part of the same company as the transmission owner. There is also a potential conflict of interest when the transmission owner evaluates the interconnection requirements of a merchant transmission developer which is a competitor of the transmission owner.

## Regional Transmission Expansion Plan (RTEP)

- Artificial Island is an area in southern New Jersey that includes nuclear units at Salem and at Hope Creek in the PSEG Zone. On April 29, 2013, PJM issued a request for proposal (RFP), seeking technical solutions to improve stability issues and operational performance under a range of anticipated system conditions, and the elimination of potential planning criteria violations in this area. On July 30, 2015, the PJM Board of Managers accepted PJM's recommendation to assign the project to LS Power, a merchant developer, PSEG, and PHI with a total cost estimate between $263M and $283M.[137] [138]
- On October 25, 2012, Schedule 12 of the tariff and Schedule 6 of the OA were changed to address FERC Order No. 1000 reforms to the cost allocation requirements for local and regional transmission planning projects that were formerly defined in Order No. 890. The new approach was applied for the first time to the 2013 RTEP. Since then, some developers have raised concern with the cost allocations using the new solution based dfax method.

## Backbone Facilities

- PJM baseline transmission projects are implemented to resolve reliability criteria violations. PJM backbone transmission projects are a subset of significant baseline projects, which are intended to resolve multiple reliability criteria violations and congestion issues and which may have substantial impacts on energy and capacity markets. There is currently only one backbone project under development, Surry Skiffes Creek 500kV.

## Transmission Facility Outages

- PJM maintains a list of reportable transmission facilities. When the reportable transmission facilities need to be taken out of service, PJM transmission owners are required to report planned transmission facility outages as early as possible. PJM processes the transmission facility outage requests according to rules in PJM's Manual 3 to decide if the outage is on time, late, or past its deadline and whether or not they will allow the outage.[139]
- There were 19,593 transmission outage requests submitted for 2015. Of the requested outages, 79.2 percent were planned for five days or shorter and 4.9 percent were planned for longer than 30 days. Of the requested outages, 49.1 percent were late according to the rules in PJM's Manual 3.
- There were 19,614 transmission outage requests submitted for 2014. Of the requested outages, 79.8

135 See Earlier Queue Submittal Task Force at <http://www.pjm.com/committees-and-groups/task-forces/eqstf.aspx>

136 See PJM, OATT, Part I, § 1 "Definitions"

137 See "Artificial Island Recommendations," presented at the TEAC meeting on April 28, 2015 at <http://www.pjm.com/~/media/committees-groups/committees/teac/20150428-ai/20150428-artificial-island-recommendations.ashx>

138 See letter from Terry Boston concerning the Artificial Island Project at <http://www.pjm.com/~/media/documents/reports/board-statement-on-artificial-island-project.ashx>

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

percent were planned for five days or shorter and 5.4 percent were planned for longer than 30 days. Of the requested outages, 48.7 percent were late according to the rules in PJM's Manual 3.

## Section 12 Recommendations

The MMU recommends improvements to the planning process.

- 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. (Priority: Low. First reported 2001. Status: Not adopted.)
- The MMU recommends the creation of a mechanism to permit a direct comparison, or competition, between transmission and generation alternatives, including which alternative is less costly and who bears the risks associated with each alternative. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that rules be implemented to permit competition to provide financing for transmission projects. This competition could reduce the cost of capital for transmission projects and significantly reduce total costs to customers. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that rules be implemented to require that project cost caps on new transmission projects be part of the evaluation of competing projects. (Priority: Low. New recommendation. Status: Not adopted.)
- The MMU recommends that barriers to entry be addressed in a timely manner in order to help ensure that the capacity market will result in the entry of new capacity to meet the needs of PJM market participants and reflect the uncertainty and resultant risks in the cost of new entry used to establish the capacity market demand curve in RPM. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends that the question of whether Capacity Injection Rights (CIRs) should persist after the retirement of a unit be addressed. Even if the treatment of CIRs remains unchanged, the rules need to ensure that incumbents cannot exploit control of CIRs to block or postpone entry of competitors.[140] (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends outsourcing interconnection studies to an independent party to avoid potential conflicts of interest. Currently, these studies are performed by incumbent transmission owners under PJM's direction. This creates potential conflicts of interest, particularly when transmission owners are vertically integrated and the owner of transmission also owns generation. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends improvements in queue management including that PJM establish a review process to ensure that projects are removed from the queue if they are not viable, as well as a process to allow commercially viable projects to advance in the queue ahead of projects which have failed to make progress, subject to rules to prevent gaming. (Priority: Medium. First reported 2013. Status: Partially adopted.)
- The MMU recommends an analysis of the study phase of PJM's transmission planning to reduce the need for postponements of study results, to decrease study completion times, and to improve the likelihood that a project at a given phase in the study process will successfully go into service. (Priority: Medium. First reported Q1, 2014. Status: Partially adopted, 2014.)
- The MMU recommends that PJM establish fair terms of access to rights of way and property, such as at substations, in order to remove any barriers to entry and permit competition between incumbent transmission providers and merchant transmission providers in the RTEP. (Priority: Medium. First reported 2014. Status: Not adopted.)
- The MMU recommends that PJM enhance the transparency and queue management process for merchant transmission investment. Issues related to data access and complete explanations of cost impacts should be addressed. The goal should be to remove barriers to competition from merchant

140 See "Comments of the Independent Market Monitor for PJM," Docket No. ER12-1177-000, <http://www.monitoringanalytics.com/reports/Reports/2012/IMM_Comments_ER12-1177-000_20120312.pdf>.

transmission. (Priority: Medium. First reported Q2, 2015. Status: Not adopted.)

- The MMU recommends consideration of changing the minimum distribution factor in the allocation from .01 to .00 and adding a threshold minimum impact on the load on the line. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that PJM reevaluate all transmission outage tickets as on time or late as if they were new requests when an outage is rescheduled and apply the standard rules for late submissions to any such outages. (Priority: Low. First reported 2014. Status: Not adopted.)
- The MMU recommends that PJM draft a clear definition of the congestion analysis required for transmission outage requests to include in Manual 3 after appropriate review. (Priority: Low. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM modify the rules to reduce or eliminate the approval of late outage requests submitted or rescheduled after the FTR auction bidding opening date. (Priority: Low. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM not permit transmission owners to divide long duration outages into smaller segments to avoid complying with the requirements for long duration outages. (Priority: Low. New recommendation. Status: Not adopted.)

## Section 12 Conclusion

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

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

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

The PJM rules for competitive transmission development through the RTEP should build upon FERC Order No. 1000 to create real competition between incumbent transmission providers and merchant transmission providers. PJM should enhance the transparency and queue management process for merchant transmission investment. Issues related to data access and complete explanations of cost impacts should be addressed. The goal should be to remove barriers to competition from merchant transmission. Another element of opening competition would be to consider transmission owners' ownership of property and rights of way at or around transmission substations. In many cases, the land acquired included property intended to support future expansion of the grid. Incumbents have included the costs of the property in their rate base. Because PJM now has the responsibility for planning the development of the grid under its RTEP process, property bought to facilitate future expansion should be a part of the RTEP process and be made available to all providers on equal terms.

There are currently no market incentives for transmission owners to submit and complete transmission outages in a timely and efficient manner. Requiring transmission owners to pay does not create an effective incentive

when those payments are passed through to transmission customers. The process for the submission of planned transmission outages needs to be carefully reviewed and redesigned to limit the ability of transmission owners to submit transmission outages that are late for FTR Auction bid submission dates and are late for the Day-Ahead Energy Market. The submission of late transmission outages can inappropriately affect market outcomes when market participants do not have the ability to modify market bids and offers.

## Overview: Section 13, "FTR and ARRs"

### Auction Revenue Rights

#### Market Structure

- **ARR Allocations.** PJM's actions to address prior low levels of FTR revenue adequacy included PJM's assumption of higher outage levels and PJM's decision to include additional constraints (closed loop interfaces) both of which reduced system capability in the FTR auction model. PJM's actions led to a significant reduction in the allocation of Stage 1B and Stage 2 ARRs. ARR allocation quantities were significantly reduced from historic levels for both the 2014 to 2015 and 2015 to 2016 planning periods. For the 2014 to 2015 planning period, Stage 1B and Stage 2 ARR allocations were reduced 84.9 percent and 88.1 percent from the 2013 to 2014 planning period. For the 2015 to 2016 planning period, Stage 1B and Stage 2 ARR allocations were reduced 79.7 percent from the 2013 to 2014 planning period.
- **Residual ARRs.** If ARR allocations are reduced as the result of a modeled transmission outage and the transmission outage ends during the relevant planning year, the result is that residual ARRs may be available. These residual ARRs are automatically assigned to eligible participants the month before the effective date. Residual ARRs are only available on paths prorated in Stage 1 of the annual ARR allocation, are only effective for single, whole months and cannot be self scheduled. Residual ARR clearing prices are based on monthly FTR auction clearing prices.

  In the 2015 to 2016 planning period, PJM allocated a total of 26,845.4 MW of residual ARRs, up from 22,737.4 MW in the first seven months of the 2014 to 2015 planning period, with a total target allocation of $7.5 million for the 2015 to 2016 planning period, down from $9.0 million for the first seven months of the 2014 to 2015 planning period. Total Residual ARR allocations for the 2013 to 2014 planning period were 15,417.5 MW for $4.7 million. This large increase in residual ARR allocations over the 2013 to 2014 planning period was primarily a result of PJM's significant reductions in Annual ARR Stage 1B allocations. The outages were only assumed in order to reduce the initial allocation. As a result, there were more available ARRs during the year which were distributed as residual ARRs.
- **ARR Reassignment for Retail Load Switching.** There were 53,343 MW of ARRs associated with $503,400 of revenue that were reassigned in the 2014 to 2015 planning period. There were 43,089 MW of ARRs associated with $504,600 of revenue that were reassigned for the first seven months of the 2015 to 2016 planning period.

#### Market Performance

- **Revenue Adequacy.** For the 2015 to 2016 planning period, the ARR target allocations, which are based on the nodal price differences from the Annual FTR Auction, were $928.8 million, while PJM collected $962.0 million from the combined Long Term, Annual and Monthly Balance of Planning Period FTR Auctions, making ARRs revenue adequate. For the 2014 to 2015 planning period, the ARR target allocations were $735.3 million while PJM collected $767.9 million from the combined Long Term, Annual and Monthly Balance of Planning Period FTR Auctions. The increase in ARR target allocations and auction revenue, despite decreased volume, is a result of increased prices resulting from the reduced allocation of Stage 1B and Stage 2 ARRs. For the 2015 to 2016 planning period ARR dollars per MW increased 15.6 percent relative to the 2013 to 2014 planning period.
- **ARRs as an Offset to Congestion.** ARRs did not serve as an effective way to return congestion revenues to load. Total ARR and self scheduled FTR revenue offset only 63.8 percent of total congestion costs including congestion in the Day-Ahead Energy Market and the balancing energy market for the 2014 to 2015 planning period. In the first seven months of the 2015 to 2016 planning period, total

ARR and self scheduled FTR revenues offset 85.8 percent of total congestion costs.

## Financial Transmission Rights

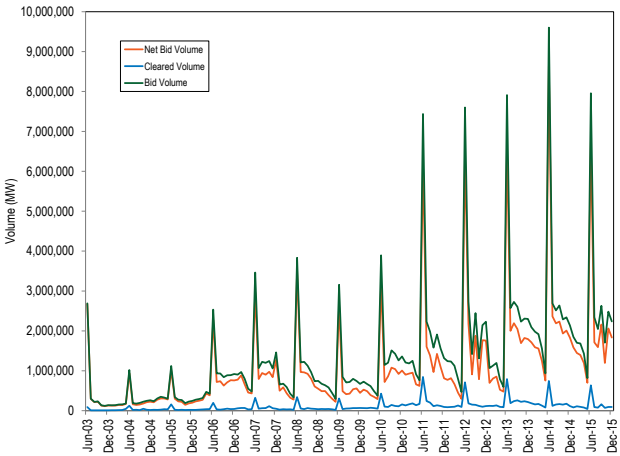
### Market Structure

- **Supply.** The principal binding constraints limiting the supply of FTRs in the 2016 to 2019 Long Term FTR Auction include the Kenney – Stockton line in DPL and the Glenview – Kleeman line in DEOK. The principal binding constraints limiting the supply of FTRs in the Annual FTR Auction for the 2015 to 2016 planning period include the Bush – Lafayette flowgate in MISO and the Oakgrove – Galesburg flowgate in MISO.

  Market participants can sell FTRs. In the 2016 to 2019 Long Term FTR Auction, total participant FTR sell offers were 327,980 MW, up from 240,748 in the 2015 to 2018 Long Term FTR Auction. In the 2015 to 2016 Annual FTR Auction, total participant sell offers were 378,744 MW, up from 271,368 MW in the 2014 to 2015 Annual FTR Auction. In the Monthly Balance of Planning Period FTR Auctions for the 2015 to 2016 planning period, total participant FTR sell offers were 3,495,474 MW, up from 2,424,369 MW for the same period during the 2014 to 2015 planning period.

- **Demand.** In the 2016 to 2019 Long Term FTR Auction, total FTR buy bids were 2,459,946 MW, down 21.3 percent from 3,124,613 MW the previous planning period. There were 2,461,662 MW of buy and self-scheduled bids in the 2015 to 2016 Annual FTR Auction, down 24.7 percent from 3,270,311 MW the previous planning period. The total FTR buy bids from the Monthly Balance of Planning Period FTR Auctions for the 2015 to 2016 planning period decreased 11.5 percent from 17,863,834 MW for the same time period of the prior planning period, to 15,813,526 MW.

**Figure 18 Long Term, Annual and Monthly FTR Auction bid and cleared volume: June 2003 through December 2015**




- **Patterns of Ownership.** For the 2016 to 2019 Long Term FTR Auction, financial entities purchased 70.1 percent of prevailing flow FTRs and 78.5 percent of counter flow FTRs. For the 2015 to 2016 Annual FTR Auction, financial participants purchased 56.3 percent of all prevailing flow FTRs and 75.0 percent of all counter flow FTRs. For the Monthly Balance of Planning Period Auctions, financial entities purchased 74.9 percent of prevailing flow and 76.8 percent of counter flow FTRs for January through December of 2015. Financial entities owned 65.9 percent of all prevailing and counter flow FTRs, including 60.6 percent of all prevailing flow FTRs and 79.6 percent of all counter flow FTRs during the period from January through December 2015.

### Market Behavior

- **FTR Forfeitures.** Total forfeitures for the 2015 to 2016 planning period were $0.2 million for Increment Offers, Decrement Bids and UTC Transactions.

- **Credit Issues.** There were three collateral defaults and seven payment defaults for 2015. Two collateral defaults totaled $710,300 and seven payment defaults totaled $1,726,641 for Intergrid Mideast Group, LLC. There was one other collateral default for the first nine months of 2015 for $35,000, which was promptly cured. There were no additional defaults in the last quarter of 2015.

  PJM terminated Intergrid's membership as of April 23, 2015, and FERC approved PJM's termination as

of June 23, 2015. Some of Intergrid's invoices were paid through Intergrid, a guarantor or cash collateral posted with PJM. Intergrid held FTRs at the time they were declared in default. PJM has liquidated all of Intergrid's FTR positions in accordance with Section 7.3.9 of the Operating Agreement.[141] PJM liquidated 500.8 MW of Intergrid's FTRs in the June Monthly Balance of Planning Period Auction for a net of $509,732 in revenue. PJM also liquidated 417.2 MW of Long Term FTRs for various planning periods for a net of $230,318 in cost. The net revenue result of Intergrid's FTR liquidation is $279,414. PJM has notified its Members that the Intergrid default will not result in any default allocation assessments in accordance with Section 15.2.2 of the Operating Agreement.[142]

## Market Performance

- **Volume.** The 2016 to 2019 Long Term FTR Auction cleared 277,397 MW (11.3 percent) of demand of FTR buy bids, down 0.2 percent from 277,865 MW (8.9 percent) in the 2015 to 2018 Long Term FTR Auction. The Long Term FTR Auction also cleared 61,210 MW (18.7 percent) of FTR sell offers, compared to 34,629 (14.4 percent), a 76.8 percent increase.

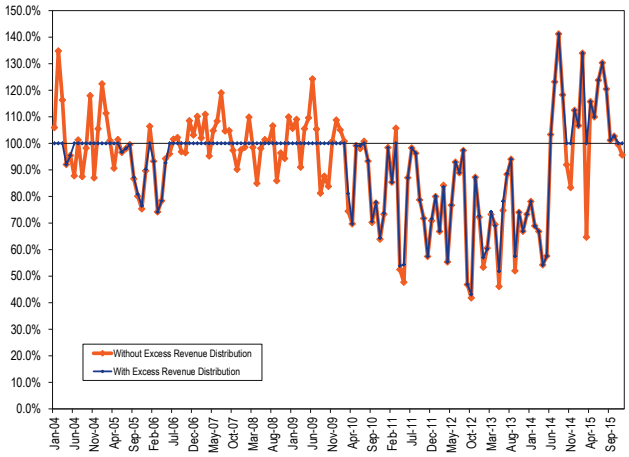
  In the Annual FTR Auction for the 2015 to 2016 planning period 378,328 MW (15.4 percent) of buy and self-schedule bids cleared, up 3.4 percent from 365,843 MW (10.4 percent) for the previous planning period. In the 2015 to 2016 planning period Monthly Balance of Planning Period FTR Auctions 1,466,985 MW (9.3 percent) of FTR buy bids and 803,463 MW (23.0 percent) of FTR sell offers cleared.

- **Price.** The weighted-average buy-bid FTR price in the 2016 to 2019 Long Term FTR Auction was $0.05 per MW, up from $0.04 per MW for the 2015 to 2018 planning period. The weighted-average buy-bid FTR price in the Annual FTR Auction for the 2015 to 2016 planning period was $0.31 per MW, up from $0.29 per MW in the 2014 to 2015 planning period. The weighted-average buy-bid cleared FTR price in the Monthly Balance of Planning Period FTR Auctions for the 2015 to 2016 planning period was $0.25, up from $0.16 per MW for the same period in the 2014 to 2015 planning period.

- **Revenue.** The 2016 to 2019 Long Term FTR Auction generated $23.2 million of net revenue for all FTRs, up from $9.0 million for the 2015 to 2018 Long Term FTR Auction. The 2015 to 2016 Annual FTR Auction generated $936.3 million in net revenue, up from $748.6 million for the 2014 to 2015 Annual FTR Auction. The Monthly Balance of Planning Period FTR Auctions generated $25.8 million in net revenue for all FTRs for the 2015 to 2016 planning period, up from $12.5 million for the same time period in the 2014 to 2015 planning period.

- **Revenue Adequacy.** FTRs were paid at 100 percent of the target allocation level for the 2015 to 2016 planning period. This high level of revenue adequacy was primarily a result of actions taken by PJM to reduce the level of available ARRs and FTRs. PJM's actions included PJM's assumption of higher outage levels and PJM's decision to include additional constraints (closed loop interfaces) both of which reduced system capability in the FTR auction model. PJM's actions led to a significant reduction in the allocation of Stage 1B and Stage 2 ARRs.

**Figure 19 FTR payout ratio by month, excluding and including excess revenue distribution: January 2004 through December 2015**




- **Profitability.** FTR profitability is the difference between the revenue received for an FTR and the cost of the FTR. In 2015, FTRs were profitable overall, with $453.5 million in profits for physical entities, of which $325.9 million was from self-

141 *See* PJM OATT. Liquidation of Financial Transmission Rights in the Event of Member Default. § 7.3.9.

142 *See* PJM OATT. Default Allocation Assessment § 15.2.2.

scheduled FTRs, and $182.3 million for financial entities.

## Section 13 Recommendations

- The MMU recommends that the ARR/FTR design be modified to ensure that all congestion revenues are returned to load. (Priority: High. New recommendation. Status: Not adopted.)
- The MMU recommends that all FTR auction revenue be distributed to ARR holders. (Priority: High. New recommendation. Status: Not adopted.)
- The MMU recommends that historical generation to load paths be eliminated as a basis for allocating ARRs. (Priority: High. New recommendation. Status: Not adopted.)
- The MMU recommends that counter flow FTRs be eliminated. (Priority: High. New recommendation. Status: Not adopted.)
- The MMU recommends that FTR auction revenues not be used to buy counter flow FTRs with the purpose of improving FTR payout ratios.[143] (Priority: High. New recommendation. Status: Not adopted.)
- The MMU recommends that PJM report correct monthly payout ratios to reduce understatement of payout ratios on a monthly basis. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM eliminate portfolio netting to eliminate cross subsidies among FTR marketplace participants. (Priority: High. First reported 2012. Status: Not adopted. Pending before FERC.)
- The MMU recommends that PJM eliminate subsidies to counter flow FTRs by applying the payout ratio to counter flow FTRs in the same way the payout ratio is applied to prevailing flow FTRs. (Priority: High. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM eliminate geographic cross subsidies. (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM improve transmission outage modeling in the FTR auction models. (Priority: Low. First reported 2013. Status: Adopted partially, 14/15 planning period.)
- The MMU recommends that PJM reduce FTR sales on paths with persistent overallocation of FTRs including clear rules for what defines persistent overallocation and how the reduction will be applied. (Priority: High. First reported 2013. Status: Adopted partially, 14/15 planning period.)
- The MMU recommends that PJM implement a seasonal ARR and FTR allocation system to better represent outages. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that the basis for the Stage 1A assignments be reviewed and made explicit, that the role of out of date generation to load paths be reviewed and that the building of the transmission capability required to provide all defined Stage 1A allocations be reviewed. (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM apply the FTR forfeiture rule to up to congestion transactions consistent with the application of the FTR forfeiture rule to increment offers and decrement bids. (Priority: High. First reported 2013. Status: Not adopted. Pending before FERC.)
- The MMU recommends that PJM examine the mechanism by which self scheduled FTRs are allocated when load switching among LSEs occurs throughout the planning period. (Priority: Low. First reported 2011. Status: Not adopted.)

## Section 13 Conclusion

The annual ARR allocation should be designed to return congestion revenues to firm transmission service customers, without requiring contract path physical transmission rights that are difficult or impossible to define and enforce in LMP markets. The fixed charges paid for firm transmission services result in the transmission system which provides physically firm transmission service which results in load paying congestion revenues.

After the introduction of LMP markets, financial transmission rights (FTRs) permitted the loads which pay for the transmission system to continue to receive those benefits in the form of revenues which offset congestion to the extent permitted by the transmission system. Financial transmission rights and the associated revenues were directly provided to loads in recognition

143 See PJM. "Manual 6: Financial Transmission Rights" Revision 16 (June 1, 2014), p. 56.

of the fact that loads pay for the transmission system which permits low cost generation to be delivered to load. Another way of describing the result is that FTRs and the associated revenues were directly provided to loads in recognition of the fact that load pays locational prices which result in load payments in excess of generation revenues which are the source congestion revenues in an LMP market. In other words, load payments in excess of generation revenues are the source of the funds to pay FTRs. In an LMP system, the only way to ensure that load receives the benefits associated with the use of the transmission system to deliver low cost energy is to use FTRs to pay back to load the difference between the total load payments and the total generation revenues, which equals total congestion revenues.

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

As a result of the creation of ARRs and other changes to the design, the current ARR/FTR design does not serve as an efficient way to ensure that load receives all the congestion revenues or has the ability to receive the auction revenues associated with all the potential congestion revenues. Total ARR and self scheduled FTR revenue offset only 63.8 percent of total congestion costs including congestion in the Day-Ahead Energy Market and the balancing energy market for the 2014 to 2015 planning period.

For these reasons, load should never be required to subsidize payments to FTR holders, regardless of the reason. Such subsidies have been suggested repeatedly.[144] One form of recommended subsidies would ignore balancing congestion when calculating total congestion dollars available to fund FTRs. This approach would ignore the fact that loads must pay both day-ahead and balancing congestion and that congestion is defined, in an accounting sense, to equal the sum of day ahead and balancing congestion. To eliminate balancing congestion from the FTR revenue calculation would require load to pay twice for congestion. Load would have to continue paying for the physical transmission system, would have to continue paying in excess of generator revenues and not have balancing congestion included in the calculation of congestion in order to increase the payout to holders of FTRs who are not loads and who therefore did not receive an allocation of ARRs. In other words, load would have to continue providing all the funding of FTRs, while payments to FTR holders who did not receive ARRs exceed total congestion on their FTR paths and result in profits to FTR holders.

Revenue adequacy has received a lot of attention in the PJM FTR Market. There are several factors that can affect the reporting, distribution of and quantity of funding in the FTR Market. Revenue adequacy is misunderstood. FTR holders, with the creation of ARRs, do not have the right to financially firm transmission service and FTR holders do not have the right to revenue adequacy even when defined correctly. Load does have those rights based on load's payment for the transmission system and load's payment of total congestion.

Reported FTR revenue adequacy uses target allocations as the relevant benchmark. But target allocations are not the relevant benchmark. Target allocations are based on day-ahead congestion only, ignoring balancing congestion which is the other part of total congestion. FTR holders appropriately receive revenues based on actual congestion in both day-ahead and balancing markets. When day-ahead congestion differs significantly from real-time congestion, as has occurred only in recent years, this is evidence that there are reporting issues, cross subsidization issues, issues with the level of FTRs sold, and issues with modeling differences between the day-ahead and real-time markets. Such differences are not an indication that FTR holders are under paid.

The difference between the congestion payout using total congestion and the congestion payout using only day-ahead congestion illustrates the issue. For 2015, total day-ahead congestion was $1,632.1 million while total day-ahead plus balancing congestion was $1,385.3 million, compared to target allocations of $1,231.3 million in the same time period.

PJM used a more conservative approach to modeling the transmission capability for the 2014 to 2015 planning period. PJM simply assumed higher outage levels and

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

included additional constraints, both of which reduced system capability in the FTR auction model. The result was a significant reduction in Stage 1B and Stage 2 ARR allocations, and a corresponding reduction in the available quantity of FTRs, an increase in FTR prices and an increase in ARR target allocations. The market response to the reduced supply of FTRs was increased bid prices, increased clearing prices and reduced clearing quantities.

Clearing prices fell and cleared quantities increased from the 2010 to 2011 planning period through the 2013 to 2014 planning period. The market response to lower revenue adequacy was to reduce bid prices and to increase bid volumes and offer volumes. In the 2014 to 2015 and 2015 to 2016 planning periods, due to reduced ARR allocations, FTR volume decreased relative to the 2013 to 2014 planning period. The reduction in ARR allocations and resulting FTR volume caused, by definition, an improvement in revenue adequacy, and also resulted in an increase in the prices of FTRs. Increased FTR prices resulted in increased ARR target allocations, because ARR target allocations are based on the Annual FTR Auction nodal prices.

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

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

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

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

The result of removing portfolio netting and applying a payout ratio to counter flow FTRs would have increased the calculated payout ratio in the 2013 to 2014 planning period from the reported 72.8 percent to 91.0 percent. For the 2014 to 2015 planning period the payout ratio was 100 percent. The MMU recommends that counter flow and prevailing flow FTRs be treated symmetrically with respect to the application of a payout ratio.

The overallocation of Stage 1A ARRs results in FTR overallocations on the same facilities. Stage 1A ARR overallocation is a source of revenue inadequacy and cross subsidy. The origin and basis for the requirement to assign Stage 1A ARRs needs further investigation. The issues associated with over allocation appear to be based on the use of out of date generation to load ARR paths and on whether PJM has appropriately built transmission to meet the requirement.

The MMU recommends that the basis for the Stage 1A assignments be reviewed and made explicit, that the role of out of date generation to load paths be reviewed and that the building of the transmission capability required to provide all defined Stage 1A allocations be reviewed. The implementation of the MMU's recommendation to return all congestion revenues to load would also significantly affect this issue.

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

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

For the 2014 to 2015 and 2015 to 2016 planning periods FTRs have been revenue adequate. This is not because the underlying problems have been fixed. Revenue adequacy has been accomplished by limiting the amount of available ARRs and FTRs by arbitrarily decreasing the ARR allocations for Stage 1B and Stage 2 which also results in a redistribution of ARRs based on differences in allocations between Stage 1A and Stage 1B ARRs.