Introduction

2017 Q2 in Review

The results of the energy market, the results of the capacity market and the results of the regulation market were competitive in the first six months of 2017. The goal of competition is to provide customers wholesale power at the lowest possible price, but no lower. The PJM markets work. The PJM markets bring customers the benefits of competition. But the PJM markets, and wholesale power markets in the U.S., face new challenges that potentially threaten the viability of competitive markets.

Particularly in times of stress on markets and when some flaws in markets are revealed, nonmarket 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, batteries, demand side 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. Proposals for fuel diversity are generally proposals to subsidize an existing, uneconomic technology. Subsidies are tempting because they maintain existing resources and provide increased revenues to asset owners in uncertain markets. Cost of service regulation is tempting because cost of service regulation incorporates integrated resource planning and because guaranteed rates of return and fixed prices may look attractive to asset owners in uncertain markets.

It is essential that any approach to the PJM markets and the PJM Capacity Market incorporate a consistent view of how the preferred market design is expected to work to provide competitive results in a sustainable market design over the long run. A sustainable market design means a market design that results in appropriate incentives to retire units and to invest in new units over time such that reliability is ensured as a result of the functioning of the market. There are at least two broad paradigms that could result in such an outcome. The market paradigm includes a full set of markets, most importantly the energy market and capacity market, which together ensure that there are adequate revenues to incent new generation when it is needed and to incent retirement of units when appropriate. This approach will result in long term reliability at the lowest possible cost.

The quasi-market paradigm includes an energy market based on LMP but addresses the need for investment incentives via the long term contract model or the cost of service model. In the quasi-market paradigm, competition to build capacity is limited and does not include the entire PJM footprint. In the quasi-market paradigm, customers absorb the risks associated with investment in and ownership of generation assets through guaranteed payments under either guaranteed long term contracts or the cost of service approach. In the quasi-market paradigm there is no market clearing pricing to incent investment in existing units or new units. In the quasi-market paradigm there is no incentive for entities without cost of service treatment to enter and thus competition is effectively eliminated.

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, those entities 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.

The issue of external subsidies continued to evolve in the first six months of 2017. These subsidies are not directly part of the PJM market design but nonetheless threaten the foundations of the PJM capacity market and the PJM energy market as well as the competitiveness of PJM markets overall.

The Ohio subsidy proceedings and the Illinois ZEC subsidy proceeding all originated from the fact that competitive markets result in the exit of uneconomic and uncompetitive generating units. Regardless of the specific rationales offered by unit owners, the proposed solution for all such generating units has been to provide out of market subsidies in order to retain such units. These subsidies are not accurately characterized as state subsidies. These subsidies were all requested by the owners of specific uneconomic generating units in order to improve the profitability of those specific units. These subsidies were not requested to accomplish broader social goals. Broader social goals can all be met with market based mechanisms available to all market participants on a competitive basis and without discrimination.

The proponents of subsidies and of the concomitant significant alterations to the PJM capacity market and energy market designs have not demonstrated that there is a systematic problem rather than an uneconomic unit specific problem. Proponents have not demonstrated that the technologies in question actually need subsidies or higher revenues from market design changes. Over the last twelve months, fewer than a quarter of nuclear units in PJM did not recover avoidable costs from energy and capacity revenues as a result of higher energy prices, which in most cases more than offset lower capacity prices. The average LMP increase of 6.0 percent between the 12 months ended June 30, 2017, and 2016, resulted in all PJM nuclear plants recovering more than 90 percent of avoidable costs for the 12 months ended June 30, 2017, despite the fact that some units were on refueling outages. Assertions about the impact of negative prices are also not supported. Negative LMPs reduced nuclear plant net revenues by an average of 0.3 percent and a maximum of 2.6 percent in 2016.

The proposed subsidy solutions in all cases ignore the opportunity cost of subsidizing uneconomic units, which is the displacement of resources and technologies that would otherwise be economic. A decision to subsidize uneconomic units that are a significant source of energy and capacity has direct and significant impacts on other sources of energy; the opportunity costs of subsidies are substantial. Such subsidies suppress energy and capacity market prices and therefore suppress incentives for investments in new, higher efficiency thermal plants but also suppress investment incentives for the next generation of energy supply technologies and energy efficiency technologies. These impacts are long lasting but difficult to quantify precisely.

Subsidies are contagious. Competition in the markets could be replaced by competition to receive subsidies. PJM markets have no protection against this emergent threat. Accurate signals for entry and exit are necessary for well functioning and competitive markets. Competitive investors rely on accurate signals to make decisions. Similar threats to competitive markets are being discussed by unit owners in other states and the potentially precedential nature of these actions enhances the urgency of creating an effective rule to maintain competitive markets by modifying market rules to address these subsidies. Fortunately, this can be accomplished quickly by expanding the coverage of an existing rule that already reflects stakeholder compromises.

The current proposals for subsidies demonstrate that the markets need protection against subsidized, noncompetitive offers from existing as well as new resources. The current minimum offer price rule (MOPR) only addresses subsidies for new entry. The MOPR should be expanded to address subsidies for existing units, and this should be done expeditiously. This issue will not become moot unless and until the MOPR is reformed. Action is needed to correct the MOPR immediately. An existing unit MOPR is the best means to defend the PJM markets from the threat posed by subsidies intended to forestall retirement of financially distressed assets. The role of subsidies to renewables should also be clearly defined and incorporated in this rule.

A MOPR for existing units should incorporate the key elements of the current MOPR which applies only to new gas-fired CT and CC units. This design would limit the impact of subsidies on markets while ensuring that existing forms of market participation by vertically integrated, cost of service companies could continue. An existing unit MOPR is a much better way to maintain PJM markets than the PJM proposal to incorporate public policy based subsidies that could result in the capacity market becoming a residual market. The PJM capacity market and PJM markets overall cannot function as markets if the capacity market is a residual market. The current design requires all capacity resources to offer and all load to buy capacity, except those companies that elect the FRR option and keep load and generation out of the capacity market.

While an existing unit MOPR would protect markets in the short run, the underlying issues that have resulted in the pressure on markets should also be examined. Unit owners are seeking subsidies because gas prices are low resulting in low energy market margins and because flaws in the PJM capacity design have led to very substantial price suppression over the past 10 years.

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 nonmarket 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 and have had substantial impacts. Capacity prices that were suppressed substantially below the level consistent with supply and demand fundamentals affected some participants' long term decisions and led some market participants to seek subsidies. PJM has addressed the fundamental issues of the capacity market design in its Capacity Performance design, including price formation, product definition and performance incentives. But there are significant ongoing efforts to undo some of the key elements of the Capacity Performance design including performance incentives and product definition.

The proponents of subsidies are also proposing changes to the PJM market design to increase revenues to specific technologies. Within the market paradigm, the temptation to modify other elements of the PJM energy and capacity market design in order to address asserted issues related to the level of prices or the shape of the supply curve should also be resisted. The PJM supply curve is not flat. One of the lessons of the history of PJM capacity market design is that design changes based on short term, nonmarket considerations can have long term, significant, negative unintended consequences. The basic logic of LMP should not be modified in order to increase prices, or off peak prices or revenues. The shape of the supply curve does not affect the basic logic of LMP and it should not be arbitrarily modified in order to meet a goal not related to the logic of LMP. The capacity market design should not be modified in order to introduce elements of integrated resource planning to favor specific technologies. Improvements to the market design should be made when consistent with the basic market design logic, including better pricing when transmission constraints are violated and better and more locational scarcity pricing and improved incentives for flexible units by ending the practice of paying uplift to units based on inflexible operating parameters.

To the extent that there are shared broader goals related to PJM markets, they should also be addressed. If society determines that carbon is a pollutant with a negative value, a market approach to carbon is preferred to a technology or unit specific subsidy approach. Implementation of a carbon price is a market approach which would let market participants respond in efficient and innovative ways to the price signal rather than relying on planners to identify specific technologies or resources to be subsidized. If a shared goal is increased renewables in addition to their carbon attributes, a common approach to RECs would be a market based solution. Fuel diversity has also been mentioned as an issue. Current fuel diversity is higher than ever in PJM. If there is an issue, the real issue is fuel security and not fuel diversity. Significant reliance on specific fuels, including nuclear, coal and gas means that markets are at risk from a significant disruption in any one fuel. If fuel security for gas is a concern, a number of issues should be considered including the reliability of the pipelines, the compatibility of the gas pipeline regulated business model with long term guaranteed contracts and the merchant generator market business model, the degree to which electric generators have truly firm gas service and the need for a gas RTO to help ensure reliability.

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. 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.

A primary market power mitigation rule in PJM is the three pivotal supplier (TPS) test. The 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.

The price of energy must reflect supply and demand fundamentals. The inclusion of gas costs and other fuel costs in energy market offers must be based on market prices. The fuel cost policy for every unit documents the process by which a unit owner calculates the fuel cost component of its cost-based offers. Fuel cost policies must be algorithmic, verifiable and systematic to ensure that only market-based short run marginal costs are included in fuel costs, especially when markets are stressed. FERC's order on hourly offers means that generators have the ability to appropriately reflect gas cost changes in energy offers during the operating day in order to permit the energy market to reflect the current cost of gas. But offer changes should be based only on algorithmic and verifiable changes in gas cost and therefore not permit the exercise of market power.

The application of market power mitigation rules in the Day-Ahead Energy Market and the Real-Time Energy Market helps ensure competitive market outcomes even in the presence of structural market power. But the efficacy of market power mitigation rules depends on the definition of a competitive offer. A competitive offer is equal to short run marginal costs. The enforcement of market power mitigation rules is undermined if the definition of a competitive offer is not correct. The significance of competition metrics like markup is also undermined if the definition of a competitive offer is not correct. The definition of a competitive offer, as currently interpreted by PJM, is not correct. Some unit owners include costs that are not short run marginal costs in offers, including long term maintenance costs. This issue can be resolved by simple changes to the PJM Market Rules to incorporate a clear and accurate definition of short run marginal costs. PJM Manual 15 should be replaced with a straightforward description of the components of cost offers based on short run marginal costs and the correct calculation of cost offers.

The overall energy market results in the first six months of 2017 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 is not always the case during high demand hours. This is evidence of generally competitive behavior, although the behavior of some participants during high demand periods raises concerns about economic withholding. The performance of the PJM markets under high load conditions has raised a number of concerns related to aggregate market power, or the ability to increase markups substantially in tight market conditions, related to the uncertainties about the pricing and availability of natural gas, and related to the role of demand response and interchange transactions.

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. PJM real-time energy market prices increased in the first six months of 2017 compared to the first six months of 2016. The load-weighted average real-time LMP was 10.01 percent higher in the first six months of 2017 than in the first six months of 2016, $29.81 per MWh versus $27.09 per MWh. Energy prices were higher primarily as a result of higher fuel prices.

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 increased from 5.8 percent of the real-time load-weighted average LMP in the first six months of 2016 to 14.6 percent in the first six months of 2017. 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 for high demand periods 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 generation owners who routinely include high markups in price-based offers on some units. These markups do not affect prices under normal conditions but may affect prices during high demand conditions.

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. Energy net revenues are significantly affected by energy prices and fuel prices. Energy prices and fuel prices were higher in the first six months of 2017 than in the first six months of 2016. Natural gas prices increased more than LMP and new CTs and new CCs ran with lower margins as a result. Coal prices increased by less than LMP and new coal plants ran for more hours in the first six months of 2017 than in the first six months of 2016 and with higher margins. In the first six months of 2017, average energy market net revenues decreased by 59 percent for a new CT and 26 percent for a new CC. Average energy market net revenues increased by 16 percent for a new coal plant, 18 percent for a new nuclear plant, and 26 percent for a new wind installation, as compared to the first six months of 2016.

Load pays for the transmission system and contributes 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 ensure that load receives the rights to congestion revenues, without requiring contract path physical transmission rights that are impossible to define correctly and enforce in nodal, network 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 that load receives the auction revenues associated with all the potential congestion revenues.

The goal of the design should be to assign the rights to 100 percent of the congestion revenues to load. But the actual results fall well short of that goal. The current allocation of congestion revenue resulted in a total shortfall of $1,689.4 million when comparing the revenues to ARR holders to congestion, a 73.3 percent congestion offset, over the last six planning periods. Total ARR and self scheduled FTR revenues offset only 44.7 percent of congestion costs in the 2013/2014 planning period, 63.8 percent in the 2014/2015 planning period, 86.5 percent in the 2015/2016 planning period and 98.1 percent in the 2016/2017 planning period.

On September 15, 2016, FERC issued an order that moved the market design substantially further from the goal of returning congestion revenues to load. The order shifted costs to load and shifted revenues to FTR holders. The order assigned the costs of balancing congestion to load, assigned excess auction revenues to FTR holders and assigned all day-ahead congestion revenues in excess of target allocations to FTR holders. If the new rules had been in place beginning with the 2011/12 planning period and the ARR/FTR allocations had remained the same, ARR holders would have received $1,034.2 million less in congestion offsets for the 11/12 through the 16/17 planning periods. The total overpayment to FTR holders for the 11/12 through 16/17 planning period would have been $944.4 million.

The FTR/ARR design should be significantly modified in order to return the design to its original purpose and function, which was to return congestion revenues to 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 1-1 shows selected summary statistics describing PJM markets.

Table 1-1 PJM Market Summary Statistics: January 1 through June 30, 2016 and 2017[1 2]

	Jan - Jun, 2016	Jan - Jun, 2017	Percent Change
Load	372,715 GWh	369,316 GWh	(0.9%)
Generation	381,800 GWh	390,187 GWh	2.2%
Net Actual Interchange	5,656 GWh	(10,739) GWh	(290%)
Losses	7,223 GWh	7,139 GWh	(1.2%)
Regulation Requirement*	613 MW	660 MW	7.7%
RTO Primary Reserve Requirement	2,175 MW	2,175 MW	0.0%
Total Billing	$18.29 Billion	$18.96 Billion	3.7%
Peak	Jun 20, 2016 16:00	Jun 12, 2017 17:00	
Peak Load	134,958 MW	140,937 MW	4.4%
Installed Capacity	As of 6/30/2016	As of 6/30/2017	
Installed Capacity	182,050 MW	183,089 MW	0.6%

* This is an hourly average stated in effective MW.

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 Positive net interchange values represent imports and negative net interchange values represent exports. Imports and exports are reported in Section 9, "Interchange Transactions."

PJM Market Background

The PJM Interconnection, L.L.C. (PJM) operates a centrally dispatched, competitive wholesale electric power market that, as of June 30, 2017, had installed generating capacity of 183,089 megawatts (MW) and 1,007 members including market buyers, sellers and traders of electricity in a region including more than 65 million people in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia (Figure 1-1).[3 4 5]

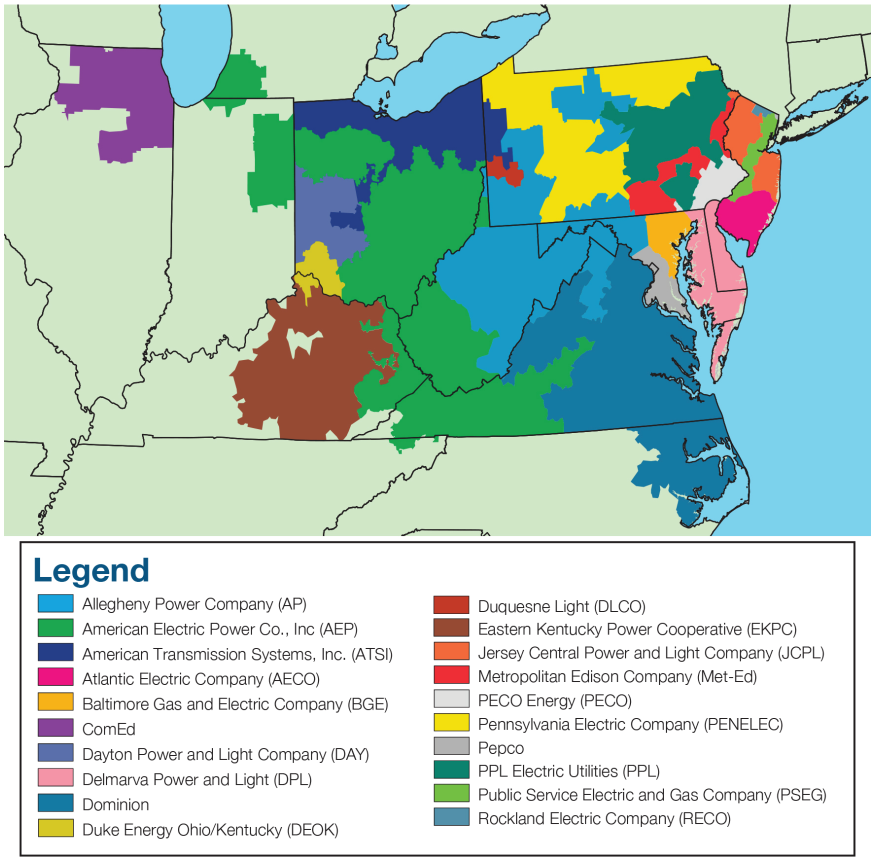
As part of the market operator function, PJM coordinates and directs the operation of the transmission grid and plans transmission expansion improvements to maintain grid reliability in this region.

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

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

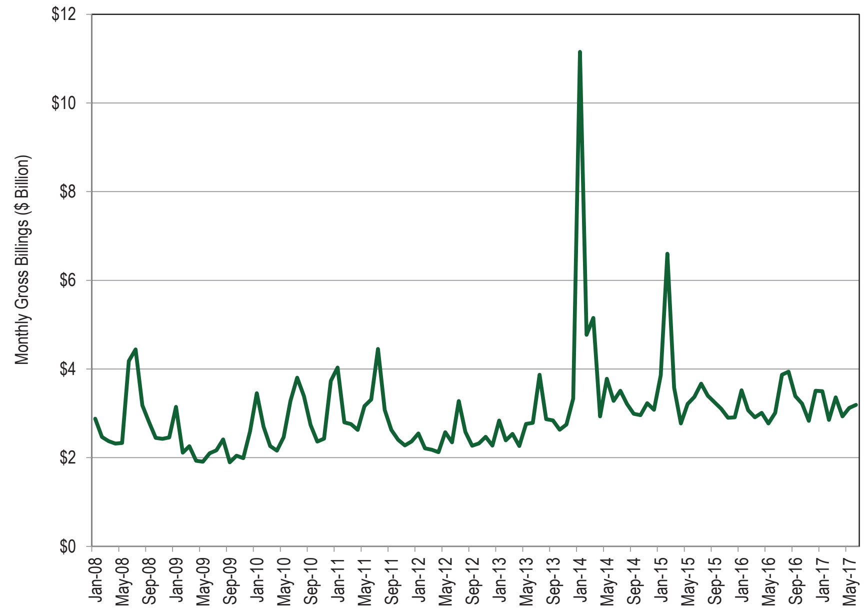
5 See the *2016 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography" for maps showing the PJM footprint and its evolution prior to 2017.

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



In the first six months of 2017, PJM had total billings of $18.96 billion, an increase of 3.7 percent from $18.29 billion in the first six months of 2016 (Figure 1-2).[6]

Figure 1-2 PJM reported monthly billings ($ Billion): 2008 through June, 2017



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 Market, 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

6 Monthly and year to date billing values are provided by PJM.

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.[7] [8] 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 the first six months of 2017, including market structure, participant behavior and market performance. This report was prepared by and represents the analysis of the Independent Market Monitor for PJM, also referred to as the Market Monitoring Unit or MMU.

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

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

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

7 See also the *2016 State of the Market Report for PJM*, Volume II, Appendix B, "PJM Market Milestones."

8 Analysis of 2017 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 2017, see *2016 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography."

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

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

Market design means the rules under which the entire relevant market operates, including the software that implements the market rules. Market rules include the definition of the product, the definition of 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 the first six months of 2017:

Table 1-2 The Energy Market results were competitive

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

- The aggregate market structure was evaluated as competitive but the aggregate market power test based on pivotal suppliers indicates that the aggregate day-ahead market structure was not competitive on every day. The hourly HHI (Herfindahl-Hirschman Index) results indicate that by the FERC standards, the PJM Energy Market in the first six months of 2017 was unconcentrated. Average HHI was 952 with a minimum of 736 and a maximum of 1205 in the first six months of 2017. The fact that the average HHI is in the unconcentrated range and the maximum hourly HHI is in the moderately concentrated range does not mean that the aggregate market was competitive in all hours. As demonstrated for the day-ahead market, it is possible to have pivotal suppliers in the aggregate market even when the HHI level is not in the highly concentrated range. It is possible to have an exercise of market power even when the HHI level is not in the highly concentrated range. The number of pivotal suppliers in the energy market is a more precise measure of structural market power than the HHI. The HHI is not a definitive measure of structural market power. The PJM Energy Market peaking segment of supply was 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 because unit owners can exercise market power even when mitigated.
- 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 in most cases although issues with the implementation of market power mitigation and development of cost-based offers remain. 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.[9] 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.[10] 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 even when market power mitigation rules are applied. 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 issues related to the level of variable operating and maintenance expense 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

9 OATT Attachment M (PJM Market Monitoring Plan).

10 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.

conditions are tight and there are pivotal suppliers in the aggregate market. Aggregate market power needs to be addressed. Now that generators will be allowed to modify offers hourly, market design must reflect appropriate incentives for competitive behavior, the application of local market power mitigation needs to be fixed, the definition of a competitive offer needs to be fixed, and aggregate market power mitigation rules need to be developed. The importance of these issues is amplified by the new rules permitting cost-based offers in excess of $1,000 per MWh.

Table 1-3 The Capacity Market results were competitive

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

- The aggregate market structure was evaluated as not competitive. For almost all auctions held from 2007 to the present, the PJM region failed the three pivotal supplier test (TPS), which is conducted at the time of the auction.[11]
- 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.[12]
- 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 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 1-4 The Tier 2 Synchronized Reserve Market 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.
- 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 nonsynchronized reserve market clears with a nonzero price.

11 In the 2008/2009 RPM Third Incremental Auction, 18 participants in the RTO market passed the TPS test.
12 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.

Table 1-5 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 18.7 percent of all cleared hours in the first six months of 2017.
- 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. Offers above $0.00 set the clearing price in 1,334 hours (30.7 percent).
- Market design was evaluated as mixed because the DASR product does not include performance obligations, and 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 1-6 The Regulation Market results were competitive

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

- The regulation market structure was evaluated as not competitive for the first six months of 2017 because the PJM Regulation Market failed the three pivotal supplier (TPS) test in 91.2 percent of the hours in the first six months of 2017.
- Participant behavior in the PJM Regulation Market was evaluated as competitive for the first six months of 2017 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 noncompetitive behavior.
- Market performance was evaluated as competitive, despite significant issues with the market design.
- Market design was evaluated as flawed. 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. The result is significantly flawed market signals to existing and prospective suppliers of regulation.

Table 1-7 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. But it is not clear, in a competitive market, why the ownership structure of Long Term FTRs is so highly concentrated.
- 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. But it is not clear, in a competitive market, why FTR purchases by financial entities remain persistently profitable.
- Market design was evaluated as flawed because there are significant flaws with the basic ARR/FTR design. The market design is not an efficient way to ensure that all congestion revenues are returned to load.

Role of MMU

The FERC assigns three core functions to MMUs: reporting, monitoring and market design.[13] 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.[14]

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.

The MMU presents reports directly to PJM stakeholders, PJM staff, FERC staff, state commission staff, state commissions, other regulatory agencies and the general public. Report presentations provide an opportunity for interested parties to ask questions, discuss issues, and provide feedback to the MMU.

13 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).

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

Monitoring

To perform its monitoring function, the MMU screens and monitors the conduct of Market Participants under the MMU's broad purview to monitor, investigate, evaluate and report on the PJM Markets.[15] The MMU has direct, confidential access to the FERC.[16] The MMU may also refer matters to the attention of state commissions.[17]

The MMU monitors market behavior for violations of FERC Market Rules and PJM Market Rules, including the actual or potential exercise of market power.[18] 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…"[19 20 21] The MMU also monitors PJM for compliance with the rules, in addition to market participants.[22]

An important component of the monitoring function is the review of inputs to mitigation. The actual or potential exercise of market power is addressed in part through *ex ante* mitigation rules incorporated in PJM's market clearing software for the energy market, the capacity market and the regulation market. If a market participant fails the TPS test in any of these markets its offer is set

15 OATT Attachment M § IV.

16 OATT Attachment M § IV.K.3.

17 OATT Attachment M § IV.H.

18 OATT § I.1 ("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.")

19 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.

20 OATT § I.1.

21 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.

22 OATT Attachment M § IV.C.

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.

If the cost-based offer does not accurately reflect short run marginal cost, the market power mitigation process does not ensure competitive pricing in PJM markets. The MMU evaluates the fuel cost policy for every unit as well as the other inputs to cost-based offers. PJM Manual 15 does not clearly or accurately describe the short run marginal cost of generation. Manual 15 should be replaced with a straightforward description of the components of cost offers based on short run marginal costs and the correct calculation of cost offers. 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. Market participants, not the MMU, determine and take responsibility for offers that they submit and the market conduct that those offers represent. If the MMU has a concern about an offer, the MMU may raise that concern with the FERC or other regulatory authorities. The FERC and other regulators have enforcement and regulatory authority that they may exercise with respect to offers submitted by market participants. PJM also reviews offers, but it does so in order to determine whether offers comply with the PJM tariff and manuals. 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.

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.

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.[28] [29]

The MMU also monitors transmission planning, interconnections and rules for vertical market power issues, and with the introduction of competitive transmission development policy in Order No. 1000, horizontal market power issues.[30]

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

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," the MMU recommends specific enhancements to existing market rules and implementation of new rules that are required for

28 See OATT Attachment M–Appendix § II(p).
29 See OATT Attachment M–Appendix § III.
30 OA Schedule 6 § 1.5.
31 OATT Attachment M § IV.D.
32 *Id.*
33 *Id.*
34 *Id.*
35 OATT Attachment M § VI.A.

competitive results in PJM markets and for continued improvements in the functioning of PJM markets. [36]

In this *2017 Quarterly State of the Market Report for PJM: January through June*, the MMU includes one new recommendation. [37]

New Recommendation from Section 13, FTRs and ARRs

- The MMU recommends that Long Term FTRs be modified to include only a one year ahead FTR. (Priority: High. New recommendation. Status: Not adopted.)

Total Price of Wholesale Power

The total price of wholesale power is the total price per MWh of purchasing wholesale electricity from PJM markets. The total price is an average price and actual prices vary by location. The total price includes the price of energy, capacity, ancillary services, and transmission service, administrative fees, regulatory support fees and uplift charges billed through PJM systems. Table 1-8 shows the average price, by component, for the first six months of 2016 and 2017.

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

Components of Total Price

- The energy component is the real time load weighted average PJM locational marginal price (LMP).
- The capacity component is the average price per MWh of Reliability Pricing Model (RPM) payments.
- The transmission service charges component is the average price per MWh of network integration charges, and firm and nonfirm point to point transmission service.[38]
- The energy uplift (Operating Reserves) component is the average price per MWh of day-ahead and balancing operating reserves and synchronous condensing charges.[39]
- The reactive component is the average cost per MWh of reactive supply and voltage control from generation and other sources.[40]
- The regulation component is the average cost per MWh of regulation procured through the PJM Regulation Market.[41]
- The PJM administrative fees component is the average cost per MWh of PJM's monthly expenses for a number of administrative services, including Advanced Control Center (AC^2) and OATT Schedule 9 funding of FERC, OPSI, CAPS 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.[42]
- 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.[43]
- The emergency load response component is the average cost per MWh of the PJM Emergency Load Response Program.[44]
- 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.[45]

36 18 CFR § 35.28(g)(3)(ii)(A); see also OATT Attachment M § IV.D.
37 New or modified recommendations include all MMU recommendations that were reported for the first time, or substantially modified, in this *2017 Quarterly State of the Market Report for PJM: January through June*.
38 OATT §§ 13.7, 14.5, 27A & 34.
39 OA Schedules 1 §§ 3.2.3 & 3.3.3.
40 OATT Schedule 2 and OA Schedule 1 § 3.2.3B. The line item in Table 1-8 includes all reactive services charges.
41 OA Schedules 1 §§ 3.2.2, 3.2.2A, 3.3.2, & 3.3.2A; OATT Schedule 3.
42 OATT Schedule 12.
43 RAA Schedule 8.1.
44 OATT PJM Emergency Load Response Program.
45 OA Schedules 1 §§ 3.2.3A.01 & OATT Schedule 6.

- 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.[46]
- The synchronized reserve component is the average cost per MWh of synchronized reserve procured through the Synchronized Reserve Market.[47]
- The black start component is the average cost per MWh of black start service.[48]
- The RTO Startup and Expansion component is the average cost per MWh of charges to recover AEP, ComEd and DAY's integration expenses.[49]
- The NERC/RFC component is the average cost per MWh of NERC and RFC charges, plus any reconciliation charges.[50]
- The economic load response component is the average cost per MWh of day-ahead and real-time economic load response program charges to LSEs.[51]
- The transmission facility charges component is the average cost per MWh of Ramapo Phase Angle Regulators charges allocated to PJM Mid-Atlantic transmission owners.[52]
- The nonsynchronized reserve component is the average cost per MWh of non-synchronized reserve procured through the Nonsynchronized Reserve Market.[53]
- The emergency energy component is the average cost per MWh of emergency energy.[54]

Table 1-8 shows that Energy, Capacity and Transmission Service Charges are the three largest components of the total price per MWh of wholesale power, comprising 97.2 percent of the total price per MWh in the first six months of 2017.

46 OATT Schedule 1A.
47 OA Schedule 1 § 3.2.3A.01; PJM OATT Schedule 6.
48 OATT Schedule 6A. The line item in Table 1-8 includes all Energy Uplift (Operating Reserves) charges for Black Start.
49 OATT Attachments H-13, H-14 and H-15 and Schedule 13.
50 OATT Schedule 10-NERC and OATT Schedule 10-RFC.
51 OA Schedule 1 § 3.6.
52 OA Schedule 1 § 5.3b.
53 OA Schedule 1 § 3.2.3A.001.
54 OA Schedule 1 § 3.2.6.

Table 1-8 Total price per MWh by category: January 1 through June 30, 2016 and 2017[55]

Category	Jan-Jun 2016 $/MWh	Jan-Jun 2016 Percent of Total	Jan-Jun 2017 $/MWh	Jan-Jun 2017 Percent of Total	Percent Change Totals
Load Weighted Energy	$27.09	54.9%	$29.81	57.8%	10.1%
Capacity	$12.36	25.1%	$10.75	20.9%	(13.1%)
Capacity	$12.36	25.1%	$10.75	20.9%	(13.1%)
Capacity (FRR)	$0.00	0.0%	$0.00	0.0%	0.0%
Transmission	$8.57	17.4%	$9.56	18.5%	11.5%
Transmission Service Charges	$7.91	16.0%	$8.82	17.1%	11.5%
Transmission Enhancement Cost Recovery	$0.57	1.1%	$0.64	1.2%	13.3%
Transmission Owner (Schedule 1A)	$0.09	0.2%	$0.10	0.2%	5.8%
Transmission Facility Charges	$0.00	0.0%	$0.00	0.0%	(100.0%)
Ancillary	$0.66	1.3%	$0.78	1.5%	18.0%
Reactive	$0.39	0.8%	$0.46	0.9%	17.4%
Regulation	$0.11	0.2%	$0.13	0.2%	10.3%
Black Start	$0.09	0.2%	$0.09	0.2%	7.2%
Synchronized Reserves	$0.05	0.1%	$0.06	0.1%	9.1%
Non-Synchronized Reserves	$0.01	0.0%	$0.01	0.0%	(45.9%)
Day Ahead Scheduling Reserve (DASR)	$0.01	0.0%	$0.04	0.1%	541.0%
Administration	$0.48	1.0%	$0.53	1.0%	12.1%
PJM Administrative Fees	$0.44	0.9%	$0.50	1.0%	12.9%
NERC/RFC	$0.03	0.1%	$0.03	0.1%	1.1%
RTO Startup and Expansion	$0.00	0.0%	$0.00	0.0%	3.2%
Energy Uplift (Operating Reserves)	$0.17	0.3%	$0.11	0.2%	(35.3%)
Demand Response	$0.01	0.0%	$0.01	0.0%	(35.0%)
Load Response	$0.01	0.0%	$0.01	0.0%	(35.0%)
Emergency Load Response	$0.00	0.0%	$0.00	0.0%	0.0%
Emergency Energy	$0.00	0.0%	$0.00	0.0%	0.0%
Total Price	$49.33	100.0%	$51.54	100.0%	4.5%

Table 1-9 shows the inflation adjusted average price, by component, for the first six months of 2016 and 2017.[56]

55 Note: The totals in this table include after the fact billing adjustments and may not match totals presented in past reports.
56 To obtain the inflation adjusted monthly load-weighted average LMP, the PJM system-wide load-weighted average LMP is deflated using the US Consumer Price Index for all items, Urban Consumers (base period: January 1998), published by *Bureau of Labor Statistics*. <http://download.bls.gov/pub/time.series/cu/cu.data.1.AllItems> (July 14, 2017)

Table 1-9 Inflation adjusted total price per MWh by category: January 1 through June 30, 2016 and 2017[57]

Category	Jan-Jun 2016 $/MWh	Jan-Jun 2016 Percent of Total	Jan-Jun 2017 $/MWh	Jan-Jun 2017 Percent of Total	Percent Change Totals
Load Weighted Energy	$18.34	54.9%	$19.74	57.8%	7.6%
Capacity	$8.37	25.1%	$7.11	20.9%	(15.0%)
Capacity	$8.37	25.1%	$7.11	20.9%	(15.0%)
Capacity (FRR)	$0.00	0.0%	$0.00	0.0%	0.0%
Transmission	$5.80	17.4%	$6.33	18.5%	9.1%
Transmission Service Charges	$5.35	16.0%	$5.84	17.1%	9.1%
Transmission Enhancement Cost Recovery	$0.38	1.1%	$0.42	1.2%	10.9%
Transmission Owner (Schedule 1A)	$0.06	0.2%	$0.06	0.2%	3.5%
Transmission Facility Charges	$0.00	0.0%	$0.00	0.0%	(100.0%)
Ancillary	$0.45	1.3%	$0.52	1.5%	15.4%
Reactive	$0.27	0.8%	$0.30	0.9%	14.9%
Regulation	$0.08	0.2%	$0.08	0.2%	7.9%
Black Start	$0.06	0.2%	$0.06	0.2%	5.0%
Synchronized Reserves	$0.03	0.1%	$0.04	0.1%	7.0%
Non-Synchronized Reserves	$0.01	0.0%	$0.00	0.0%	(47.3%)
Day Ahead Scheduling Reserve (DASR)	$0.00	0.0%	$0.03	0.1%	529.3%
Administration	$0.32	1.0%	$0.35	1.0%	9.7%
PJM Administrative Fees	$0.30	0.9%	$0.33	1.0%	10.4%
NERC/RFC	$0.02	0.1%	$0.02	0.1%	(1.0%)
RTO Startup and Expansion	$0.00	0.0%	$0.00	0.0%	0.0%
Energy Uplift (Operating Reserves)	$0.11	0.3%	$0.07	0.2%	(36.9%)
Demand Response	$0.01	0.0%	$0.00	0.0%	(36.8%)
Load Response	$0.01	0.0%	$0.00	0.0%	(36.8%)
Emergency Load Response	$0.00	0.0%	$0.00	0.0%	0.0%
Emergency Energy	$0.00	0.0%	$0.00	0.0%	0.0%
Total Price	$33.40	100.0%	$34.13	100.0%	2.2%

57 Note: The totals in this table include after the fact billing adjustments and may not match totals presented in past reports.

Table 1-10 shows the average price, by component of the total wholesale power price per MWh, for calendar years 1999 through 2016.

Table 1-10 Total price per MWh by category: Calendar Years 1999 through 2016[58]

Category	1999 $/MWh	2000 $/MWh	2001 $/MWh	2002 $/MWh	2003 $/MWh	2004 $/MWh	2005 $/MWh	2006 $/MWh	2007 $/MWh	2008 $/MWh	2009 $/MWh	2010 $/MWh	2011 $/MWh	2012 $/MWh	2013 $/MWh	2014 $/MWh	2015 $/MWh	2016 $/MWh
Load Weighted Energy	$34.07	$30.72	$36.65	$31.60	$41.23	$44.34	$63.46	$53.35	$61.66	$71.13	$39.05	$48.35	$45.94	$35.23	$38.66	$53.14	$36.16	$29.23
Capacity	$0.14	$0.25	$0.27	$0.12	$0.08	$0.09	$0.03	$0.03	$3.53	$7.80	$10.78	$12.15	$10.24	$6.57	$7.24	$9.21	$11.25	$10.96
Capacity	$0.14	$0.25	$0.27	$0.12	$0.08	$0.09	$0.03	$0.03	$3.53	$7.80	$10.78	$12.15	$9.71	$6.05	$7.13	$9.01	$11.12	$10.96
Capacity (FRR)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.53	$0.52	$0.11	$0.20	$0.13	$0.00
Transmission	$3.49	$4.13	$3.56	$3.46	$3.64	$3.38	$2.80	$3.27	$3.55	$3.83	$4.22	$4.33	$4.86	$5.32	$5.65	$6.46	$7.69	$8.42
Transmission Service Charges	$3.41	$4.03	$3.48	$3.39	$3.57	$3.28	$2.71	$3.18	$3.45	$3.68	$4.03	$4.04	$4.49	$4.90	$5.21	$5.96	$7.09	$7.81
Transmission Enhancement Cost Recovery	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.01	$0.06	$0.11	$0.20	$0.27	$0.34	$0.36	$0.41	$0.51	$0.52
Transmission Owner (Schedule 1A)	$0.07	$0.09	$0.08	$0.07	$0.07	$0.10	$0.09	$0.09	$0.09	$0.09	$0.09	$0.09	$0.09	$0.08	$0.08	$0.09	$0.09	$0.09
Transmission Facility Charges	$0.01	$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Ancillary	$0.41	$0.68	$0.75	$0.63	$0.91	$0.91	$1.19	$0.92	$1.00	$1.15	$0.78	$0.90	$0.90	$0.84	$1.24	$0.99	$0.91	$0.72
Reactive	$0.26	$0.29	$0.22	$0.20	$0.24	$0.26	$0.26	$0.29	$0.29	$0.34	$0.36	$0.45	$0.41	$0.46	$0.76	$0.40	$0.37	$0.39
Regulation	$0.15	$0.39	$0.53	$0.42	$0.50	$0.51	$0.80	$0.53	$0.63	$0.70	$0.34	$0.36	$0.32	$0.26	$0.25	$0.33	$0.23	$0.11
Black Start	$0.00	$0.00	$0.00	$0.00	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.04	$0.14	$0.08	$0.08	$0.09
Synchronized Reserves	$0.00	$0.00	$0.00	$0.01	$0.15	$0.13	$0.11	$0.08	$0.06	$0.08	$0.05	$0.07	$0.09	$0.04	$0.04	$0.12	$0.11	$0.05
Non-Synchronized Reserves	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.02	$0.02	$0.01
Day Ahead Scheduling Reserve (DASR)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.01	$0.00	$0.01	$0.05	$0.05	$0.06	$0.05	$0.10	$0.07
Administration	$0.23	$0.26	$0.73	$0.86	$1.05	$1.00	$0.73	$0.75	$0.75	$0.41	$0.34	$0.39	$0.40	$0.46	$0.45	$0.46	$0.46	$0.47
PJM Administrative Fees	$0.23	$0.26	$0.71	$0.86	$1.05	$0.93	$0.72	$0.74	$0.72	$0.39	$0.31	$0.36	$0.37	$0.42	$0.41	$0.43	$0.43	$0.44
NERC/RFC	$0.00	-$0.00	$0.01	$0.01	$0.01	$0.01	$0.01	-$0.00	$0.01	$0.01	$0.02	$0.02	$0.02	$0.02	$0.02	$0.03	$0.03	$0.03
RTO Startup and Expansion	$0.00	$0.00	$0.00	$0.00	$0.00	$0.06	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.00
Energy Uplift (Operating Reserves)	$0.52	$0.93	$1.27	$0.72	$0.89	$0.95	$1.07	$0.47	$0.65	$0.64	$0.48	$0.80	$0.78	$0.74	$0.55	$1.15	$0.38	$0.17
Demand Response	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.03	$0.06	$0.05	$0.01	$0.03	$0.03	$0.03	$0.08	$0.08	$0.02	$0.01
Load Response	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.03	$0.06	$0.05	$0.01	$0.01	$0.01	$0.02	$0.01	$0.03	$0.02	$0.01
Emergency Load Response	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.02	$0.02	$0.01	$0.06	$0.06	$0.00	$0.00
Emergency Energy	$0.07	$0.02	$0.00	$0.00	$0.02	$0.00	$0.02	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.01	$0.00	$0.00
Total Price	$38.92	$36.98	$43.22	$37.39	$47.83	$50.66	$69.30	$58.82	$71.20	$85.01	$55.66	$66.95	$63.16	$49.20	$53.87	$71.49	$56.87	$49.99

58 Note: The totals in this table include after the fact billing adjustments and may not match totals presented in past reports.

Table 1-11 shows the inflation adjusted average price, by component of the total wholesale power price per MWh, for calendar years 1999 through 2016.[59]

Table 1-11 Inflation adjusted total price per MWh by category: Calendar Years 1999 through 2016[60]

Category	1999 $/MWh	2000 $/MWh	2001 $/MWh	2002 $/MWh	2003 $/MWh	2004 $/MWh	2005 $/MWh	2006 $/MWh	2007 $/MWh	2008 $/MWh	2009 $/MWh	2010 $/MWh	2011 $/MWh	2012 $/MWh	2013 $/MWh	2014 $/MWh	2015 $/MWh	2016 $/MWh
Load Weighted Energy	$33.04	$28.80	$33.45	$28.35	$36.24	$37.91	$52.37	$42.73	$48.06	$53.27	$29.46	$35.83	$33.01	$24.80	$26.82	$36.37	$24.69	$19.68
Capacity	$0.13	$0.23	$0.24	$0.11	$0.07	$0.08	$0.02	$0.02	$2.73	$5.85	$8.11	$9.00	$7.37	$4.63	$5.02	$6.29	$7.66	$7.39
Capacity	$0.13	$0.23	$0.24	$0.11	$0.07	$0.08	$0.02	$0.02	$2.73	$5.85	$8.11	$9.00	$6.99	$4.26	$4.94	$6.15	$7.58	$7.39
Capacity (FRR)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.38	$0.37	$0.07	$0.14	$0.09	$0.00
Transmission	$3.38	$3.88	$3.25	$3.10	$3.20	$2.88	$2.32	$2.62	$2.76	$2.87	$3.18	$3.21	$3.49	$3.74	$3.92	$4.41	$5.24	$5.67
Transmission Service Charges	$3.31	$3.79	$3.17	$3.04	$3.13	$2.80	$2.24	$2.55	$2.69	$2.76	$3.04	$2.99	$3.23	$3.45	$3.61	$4.07	$4.84	$5.26
Transmission Enhancement Cost Recovery	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.04	$0.08	$0.15	$0.20	$0.24	$0.25	$0.28	$0.34	$0.35
Transmission Owner (Schedule 1A)	$0.07	$0.08	$0.07	$0.06	$0.06	$0.08	$0.07	$0.07	$0.07	$0.07	$0.06	$0.07	$0.06	$0.06	$0.06	$0.06	$0.06	$0.06
Transmission Facility Charges	$0.01	$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Ancillary	$0.40	$0.64	$0.68	$0.56	$0.80	$0.77	$0.98	$0.74	$0.78	$0.86	$0.59	$0.66	$0.64	$0.59	$0.86	$0.67	$0.62	$0.48
Reactive	$0.25	$0.27	$0.20	$0.18	$0.21	$0.22	$0.21	$0.23	$0.23	$0.25	$0.27	$0.33	$0.29	$0.32	$0.53	$0.27	$0.25	$0.26
Regulation	$0.15	$0.37	$0.48	$0.38	$0.44	$0.43	$0.66	$0.42	$0.49	$0.52	$0.26	$0.27	$0.23	$0.18	$0.17	$0.22	$0.16	$0.07
Black Start	$0.00	$0.00	$0.00	$0.00	$0.01	$0.01	$0.02	$0.02	$0.02	$0.02	$0.02	$0.01	$0.01	$0.03	$0.10	$0.05	$0.05	$0.06
Synchronized Reserves	$0.00	$0.00	$0.00	$0.01	$0.13	$0.11	$0.09	$0.07	$0.05	$0.06	$0.04	$0.05	$0.07	$0.03	$0.03	$0.08	$0.08	$0.04
Non-Synchronized Reserves	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.01	$0.01	$0.01
Day Ahead Scheduling Reserve (DASR)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.01	$0.00	$0.01	$0.04	$0.03	$0.04	$0.03	$0.07	$0.05
Administration	$0.22	$0.24	$0.66	$0.77	$0.93	$0.85	$0.61	$0.60	$0.58	$0.31	$0.25	$0.29	$0.29	$0.32	$0.31	$0.32	$0.32	$0.32
PJM Administrative Fees	$0.22	$0.25	$0.65	$0.77	$0.92	$0.79	$0.60	$0.59	$0.56	$0.29	$0.23	$0.27	$0.26	$0.30	$0.29	$0.29	$0.29	$0.30
NERC/RFC	$0.00	-$0.00	$0.01	$0.01	$0.01	$0.01	$0.00	-$0.00	$0.01	$0.01	$0.01	$0.02	$0.01	$0.02	$0.02	$0.02	$0.02	$0.02
RTO Startup and Expansion	$0.00	$0.00	$0.00	$0.00	$0.00	$0.05	$0.00	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.00	$0.00
Energy Uplift (Operating Reserves)	$0.50	$0.87	$1.15	$0.65	$0.78	$0.81	$0.88	$0.38	$0.51	$0.48	$0.36	$0.59	$0.56	$0.52	$0.38	$0.79	$0.26	$0.12
Demand Response	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.02	$0.05	$0.03	$0.00	$0.02	$0.02	$0.02	$0.05	$0.05	$0.01	$0.01
Load Response	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.02	$0.05	$0.03	$0.00	$0.01	$0.01	$0.01	$0.01	$0.02	$0.01	$0.01
Emergency Load Response	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.01	$0.01	$0.01	$0.04	$0.04	$0.00	$0.00
Emergency Energy	$0.07	$0.02	$0.00	$0.00	$0.02	$0.00	$0.02	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total Price	$37.75	$34.68	$39.44	$33.54	$42.04	$43.32	$57.20	$47.12	$55.47	$63.68	$41.96	$49.62	$45.39	$34.63	$37.37	$48.90	$38.81	$33.66

59 To obtain the inflation adjusted monthly load-weighted average LMP, the PJM system-wide load-weighted average LMP is deflated using the US Consumer Price Index for all items, Urban Consumers (base period: January 1998), published by *Bureau of Labor Statistics*. <http://download.bls.gov/pub/time.series/cu/cu.data.1.AllItems> (July 14, 2017)

60 Note: The totals in this table include after the fact billing adjustments and may not match totals presented in past reports.

Table 1-12 shows the percent of average price, by component of the wholesale power price per MWh, for calendar years 1999 through 2016.

Table 1-12 Percent of total price per MWh by category: Calendar Years 1999 through 2016[61]

Category	Percent of Total Charges 1999	Percent of Total Charges 2000	Percent of Total Charges 2001	Percent of Total Charges 2002	Percent of Total Charges 2003	Percent of Total Charges 2004	Percent of Total Charges 2005	Percent of Total Charges 2006	Percent of Total Charges 2007	Percent of Total Charges 2008	Percent of Total Charges 2009	Percent of Total Charges 2010	Percent of Total Charges 2011	Percent of Total Charges 2012	Percent of Total Charges 2013	Percent of Total Charges 2014	Percent of Total Charges 2015	Percent of Total Charges 2016
Load Weighted Energy	87.5%	83.1%	84.8%	84.5%	86.2%	87.5%	91.6%	90.7%	86.6%	83.7%	70.2%	72.2%	72.7%	71.6%	71.8%	74.3%	63.6%	58.5%
Capacity	0.4%	0.7%	0.6%	0.3%	0.2%	0.2%	0.0%	0.0%	5.0%	9.2%	19.4%	18.1%	16.2%	13.4%	13.4%	12.9%	19.8%	21.9%
Capacity	0.4%	0.7%	0.6%	0.3%	0.2%	0.2%	0.0%	0.0%	5.0%	9.2%	19.4%	18.1%	15.4%	12.3%	13.2%	12.6%	19.6%	21.9%
Capacity (FRR)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.8%	1.1%	0.2%	0.3%	0.2%	0.0%
Transmission	9.0%	11.2%	8.2%	9.3%	7.6%	6.7%	4.0%	5.6%	5.0%	4.5%	7.6%	6.5%	7.7%	10.8%	10.5%	9.0%	13.5%	16.8%
Transmission Service Charges	8.8%	10.9%	8.0%	9.1%	7.5%	6.5%	3.9%	5.4%	4.8%	4.3%	7.2%	6.0%	7.1%	10.0%	9.7%	8.3%	12.5%	15.6%
Transmission Enhancement Cost Recovery	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.2%	0.3%	0.4%	0.7%	0.7%	0.6%	0.9%	1.0%
Transmission Owner (Schedule 1A)	0.2%	0.2%	0.2%	0.2%	0.1%	0.2%	0.1%	0.1%	0.1%	0.1%	0.2%	0.1%	0.1%	0.2%	0.2%	0.1%	0.2%	0.2%
Transmission Facility Charges	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Ancillary	1.1%	1.8%	1.7%	1.7%	1.9%	1.8%	1.7%	1.6%	1.4%	1.4%	1.4%	1.3%	1.4%	1.7%	2.3%	1.4%	1.6%	1.4%
Reactive	0.7%	0.8%	0.5%	0.5%	0.5%	0.5%	0.4%	0.5%	0.4%	0.4%	0.7%	0.7%	0.6%	0.9%	1.4%	0.6%	0.7%	0.8%
Regulation	0.4%	1.1%	1.2%	1.1%	1.1%	1.0%	1.1%	0.9%	0.9%	0.8%	0.6%	0.5%	0.5%	0.5%	0.5%	0.5%	0.4%	0.2%
Black Start	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.3%	0.1%	0.1%	0.2%
Synchronized Reserves	0.0%	0.0%	0.0%	0.0%	0.3%	0.3%	0.2%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.2%	0.2%	0.1%
Non-Synchronized Reserves	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Day Ahead Scheduling Reserve (DASR)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	0.1%	0.1%	0.2%	0.1%
Administration	0.6%	0.7%	1.7%	2.3%	2.2%	2.0%	1.1%	1.3%	1.1%	0.5%	0.6%	0.6%	0.6%	0.9%	0.8%	0.6%	0.8%	0.9%
PJM Administrative Fees	0.6%	0.7%	1.7%	2.3%	2.2%	1.8%	1.0%	1.3%	1.0%	0.5%	0.6%	0.5%	0.6%	0.9%	0.8%	0.6%	0.8%	0.9%
NERC/RFC	0.0%	-0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	-0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.0%	0.0%	0.1%	0.1%
RTO Startup and Expansion	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Energy Uplift (Operating Reserves)	1.3%	2.5%	2.9%	1.9%	1.9%	1.9%	1.5%	0.8%	0.9%	0.8%	0.9%	1.2%	1.2%	1.5%	1.0%	1.6%	0.7%	0.3%
Demand Response	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	0.0%	0.0%	0.0%	0.1%	0.1%	0.1%	0.0%	0.0%
Load Response	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Emergency Load Response	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	0.0%	0.0%
Emergency Energy	0.2%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Total Price	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

61 Note: The totals in this table include after the fact billing adjustments and may not match totals presented in past reports.

Figure 1-3 shows the contributions of load-weighted energy, capacity and transmission service charges to the total price of wholesale power for each quarter since 1999.

Figure 1-3 Top three components of quarterly total price ($/MWh): January 1, 1999 through June 30, 2017[62]

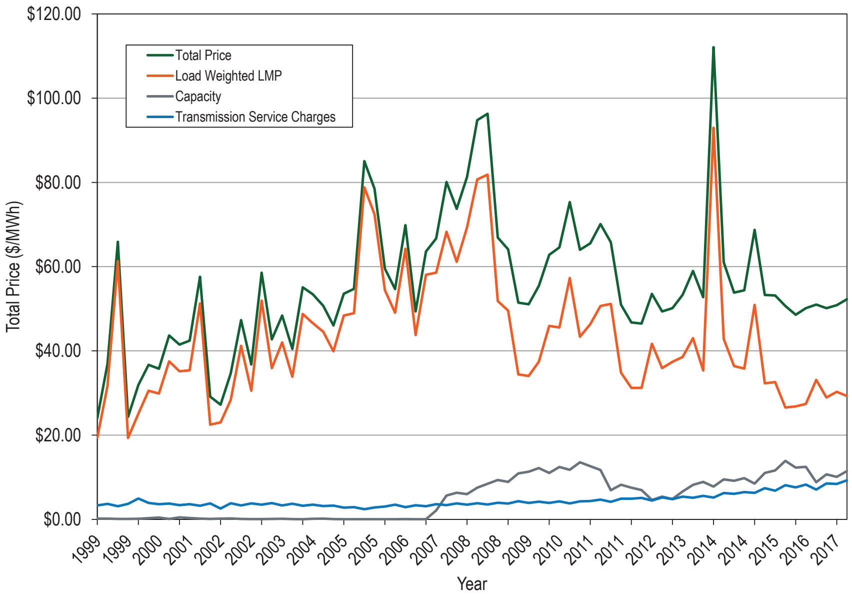
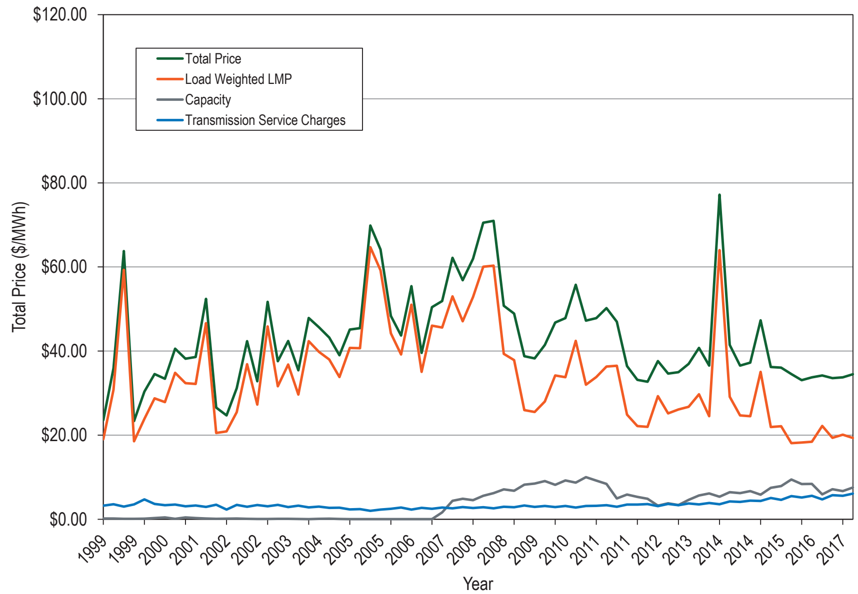


Figure 1-4 shows the inflation adjusted contributions of load-weighted energy, capacity and transmission service charges to the total price of wholesale power for each quarter since 1999.[63]

Figure 1-4 Inflation adjusted top three components of quarterly total price ($/MWh): January 1, 1999 through June 30, 2017[64]



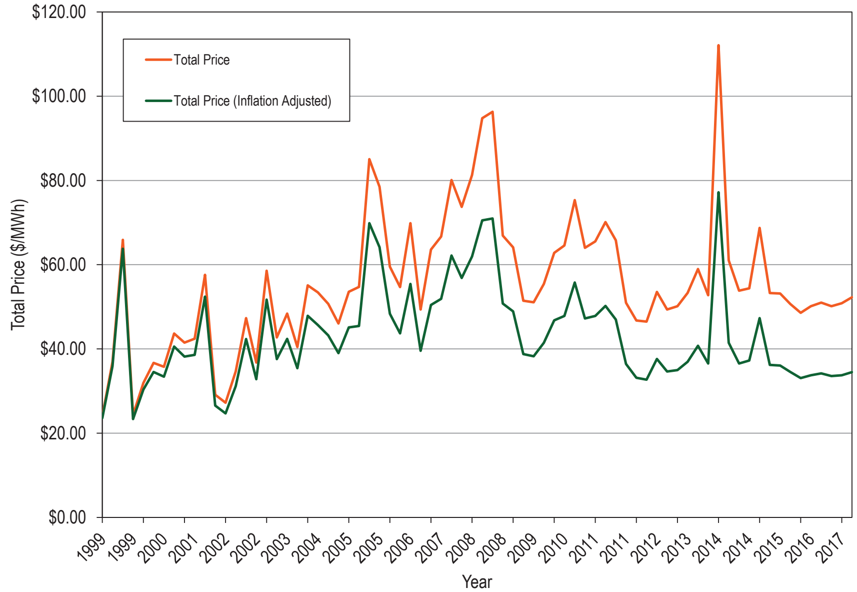
62 Note: The totals presented in this figure include after the fact billing adjustments and may not match totals presented in past reports.

63 To obtain the inflation adjusted monthly load-weighted average LMP, the PJM system-wide load-weighted average LMP is deflated using the US Consumer Price Index for all items, Urban Consumers (base period: January 1998), published by *Bureau of Labor Statistics*. <http://download.bls.gov/pub/time.series/cu/cu.data.1.AllItems> (July 14, 2017)

64 Note: The totals presented in this figure include after the fact billing adjustments and may not match totals presented in past reports.

Figure 1-5 shows the total price of wholesale power and the inflation adjusted total price of wholesale power for each quarter since 1999.[65]

Figure 1-5 Quarterly total price and quarterly inflation adjusted total price ($/MWh): January 1, 1999 through June 30, 2017[66 67]



65 To obtain the inflation adjusted monthly load-weighted average LMP, the PJM system-wide load-weighted average LMP is deflated using the US Consumer Price Index for all items, Urban Consumers (base period: January 1998), published by *Bureau of Labor Statistics*. <http://download.bls.gov/pub/time.series/cu/cu.data.1.AllItems> (July 14, 2017)

66 Note: The totals presented in this figure include after the fact billing adjustments and may not match totals presented in past reports.

67 To obtain the inflation adjusted monthly load-weighted average LMP, the PJM system-wide load-weighted average LMP is deflated using the US Consumer Price Index for all items, Urban Consumers (base period: January 1998), published by *Bureau of Labor Statistics*. <http://download.bls.gov/pub/time.series/cu/cu.data.1.AllItems> (July 14, 2017)

Section Overviews

Overview: Section 3, "Energy Market"

Market Structure

- **Supply.** Supply includes physical generation and imports and virtual transactions. The maximum of average offered real-time generation decreased by 134 MW, or 0.1 percent, from 163,250 MW in the first six months of 2016 to 163,116 MW in the first six months of 2017. In the first six months of 2017, 3,563.6 MW of new resources were added, 1,495 MW were retired.

  PJM average real-time cleared supply in the first six months of 2017 increased by 2,332 MW, or 2.7 percent, from the first six months of 2016, from 86,335 MW to 88,667 MW.

  PJM average day-ahead cleared supply in the first six months of 2017, including INCs and up to congestion transactions, increased by 4.6 percent from the first six months of 2016, from 127,748 MW to 133,595 MW, primarily as a result of an increase in UTC volumes.

- **Aggregate Pivotal Suppliers.** The PJM Energy Market requires generation from pivotal suppliers to meet the daily peak load, creating aggregate market power even when the HHI level indicates that the aggregate market is unconcentrated. Based on the HHI, the PJM Energy Market was unconcentrated overall with moderate concentration in the baseload and intermediate segments, and high concentration in the peaking segment.

- **Generation Fuel Mix.** In the first six months of 2017, coal units provided 32.4 percent, nuclear units 36.2 percent and natural gas units 24.8 percent of total generation. Compared to the first six months of 2016, generation from coal units increased 3.7 percent, generations from natural gas units increased 0.3 percent and generation from nuclear units increased 2.3 percent.

- **Fuel Diversity.** In the first six months of 2017, the fuel diversity of energy generation, measured by the fuel diversity index for energy (FDI_e), increased 0.6 percent over the first six months of 2016.

- Marginal Resources. In the PJM Real-Time Energy Market, in the first six months of 2017, coal units were 33.5 percent of marginal resources and natural gas units were 50.8 percent of marginal resources. In the first six months of 2016, coal units were 45.4 percent and natural gas units were 42.3 percent of the marginal resources.

  In the PJM Day-Ahead Energy Market, in the first six months of 2017, up to congestion transactions were 81.1 percent of marginal resources, INCs were 5.4 percent of marginal resources, DECs were 9.7 percent of marginal resources, and generation resources were 3.8 percent of marginal resources. In the first six months of 2016, up to congestion transactions were 83.3 percent of marginal resources, INCs were 3.8 percent of marginal resources, DECs were 7.3 percent of marginal resources, and generation resources were 5.5 percent of marginal resources.

- **Demand.** Demand includes physical load and exports and virtual transactions. The PJM accounting peak load during the first six months of 2017 was 140,937 MW in the HE 1700 on June 12, 2017, which was 5,979 MW, 4.4 percent, higher than the PJM peak load for the first six months of 2016, which was 134,958 MW in the HE 1600 on June 20, 2016.

  PJM average real-time demand in the first six months of 2017 decreased by 1.4 percent from 2016, from 85,800 MW to 84,570 MW. PJM average day-ahead demand in the first six months of 2017, including DECs and up to congestion transactions, increased by 3.3 percent in the first six months of 2016, from 124,576 MW to 128,685 MW.

- **Supply and Demand: Load and Spot Market.** Companies that serve load in PJM can do so using a combination of self-supply, bilateral market purchases and spot market purchases. For the first six months of 2017, 14.5 percent of real-time load was supplied by bilateral contracts, 25.1 percent by spot market purchases and 60.7 percent by self-supply. Compared with the first six months of 2016, reliance on bilateral contracts increased by 2.5 percentage points, reliance on spot market purchases did not change and reliance on self-supply decreased by 2.2 percentage points.

- **Supply and Demand: Scarcity.** There were no shortage pricing events in the first six months of 2017.

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 when the rules are designed and implemented properly. 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 decreased from 0.1 percent in the first six months of 2016 to 0 percent in the first six months of 2017. In the Real-Time Energy Market, for units committed to provide energy for local constraint relief, offer-capped unit hours decreased from 0.3 percent in the first six months of 2016 to 0.2 percent in the first six months of 2017.

  In the first six months of 2017, eleven control zones experienced congestion resulting from one or more constraints binding for 50 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.

- **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 increased from 0.1 percent in the first six months of 2016 to 0.2 percent in the first six months of 2017. In the Real-Time Energy Market, for units committed for reliability reasons, offer-capped unit hours decreased from 0.4 percent in the first six months of 2016 to 0.3 percent in the first six months of 2017.

- **Markup Index.** The markup index is a summary measure of participant offer behavior for individual marginal units. In the first six months of 2017, in the PJM Real-Time Energy Market, 93.1 percent of marginal units had offer prices less than $50 per MWh. The average dollar markups of units with offer prices less than $25 was negative when using unadjusted cost offers. The average dollar markups of units with offer prices between $25 and $50 was positive when using unadjusted cost offers. Negative markup means the unit is offering to run at a price less than its cost-based offer, demonstrating a revealed short run marginal cost that is less than the allowable cost-based offer under the PJM Market Rules. Some marginal units did have substantial markups. Using the unadjusted cost offers, the highest markup for any marginal unit in the first six months of 2017 was $248.54 while the highest markup in the first six months of 2016 was $258.16.

In the first six months of 2017, in the PJM Day-Ahead Energy Market, 92.9 percent of marginal generating units had offer prices less than $50 per MWh. The average dollar markups of units with offer prices less than $25 was positive when using unadjusted cost offers. The average dollar markups of units with offer prices between $25 and $50 was positive when using unadjusted cost offers. Using the unadjusted cost offers, the highest markup for any marginal units in the first six months of 2017 was $40.00, while the highest markup in the first six months of 2016 was $170.99.

- **Markup.** The markup frequency distributions show that a significant proportion of units make price-based offers less than the cost-based offers permitted under the PJM market rules. This behavior means that competitive price-based offers reveal actual unit marginal costs and that PJM market rules permit the inclusion of costs in cost-based offers that are not short run marginal costs.

  The markup behavior shown in the markup frequency distributions also shows that a substantial number of units were offered with high markups, consistent with the exercise of market power.

- **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. The number of units that were eligible for an FMU or AU adder declined from an average of 70 units during the first 11 months of 2014, to zero since December 2014.

- **Virtual Offers and Bids.** Any market participant in the PJM Day-Ahead Energy Market can use increment offers, decrement bids, up to congestion transactions, import transactions and export transactions as financial instruments that do not require physical generation or load. In the first six months of 2017, the average hourly increment offers submitted MW increased by 33.4 percent from 7,150 MW in the first six months of 2016 to 9,592 MW in the first six months of 2017, and cleared MW increased by 17.0 percent from 4,687 MW in the first six months of 2016 to 5,512 MW in the first six months of 2017. In the first six months of 2017, the average hourly decrement bids submitted MW increased by 25.5 percent from 7,325 MW in the first six months of 2016 to 9,243 MW in the first six months of 2017, and cleared MW increased by 12.8 percent from 4,276 MW in the first six months of 2016 to 4,894 MW in the first six months of 2017. In the first six months of 2017, the average hourly up to congestion submitted MW increased by 26.1 percent from 139,232 MW in the first six months of 2016 to 175,521 MW in the first six months of 2017, and cleared MW increased by 27.8 percent from 34,618 MW in the first six months of 2016 to 44,258 MW in the first six months of 2017.

- **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 the first six months of 2017, 55.8 percent were offered as available for economic dispatch, 3.7 percent were offered as emergency dispatch, 20.5 percent were offered as self scheduled, and 20.1 percent were offered as self scheduled and dispatchable.

Market Performance

- **Prices.** PJM LMPs are a direct measure of market performance. Price level is a good, general indicator of market performance, although the number of factors influencing the overall level of prices means it must be analyzed carefully. Among other things, overall average prices reflect changes in supply and demand, generation fuel mix, the cost of fuel, emissions related expenses, markup and local price differences caused by congestion. PJM also may administratively set prices with the creation of closed loop interfaces related to demand side resources or reactive power, the application of transmission penalty factors, or the application of price setting logic.

  PJM real-time energy market prices increased in the first six months of 2017 compared to the first six months of 2016. The load-weighted average real-time LMP was 10.1 percent higher in the first six months of 2017 than in first six months of 2016, $29.81 per MWh versus $27.09 per MWh.

  PJM day-ahead energy market prices increased in the first six months of 2017 compared to the first six months of 2016. The load-weighted average day-ahead LMP was 9.8 percent higher in the first six months of 2017 than in the first six months of 2016, $30.02 per MWh versus $27.33 per MWh.

- **Components of LMP.** In the PJM Real-Time Energy Market, in the first six months of 2017, 31.9 percent of the load-weighted LMP was the result of coal costs, 39.0 percent was the result of gas costs and 2.20 percent was the result of the cost of emission allowances.

  In the PJM Day-Ahead Energy Market, in the first six months of 2017, 21.7 percent of the load-weighted LMP was the result of the coal costs, 22.2 percent was the result of the DEC bid costs, 18.8 percent was the result of the gas costs, 23.5 percent was the result of the INC bid costs, and 3.4 percent was the result of the up to congestion transaction costs.

- **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 the first six months of 2017, the adjusted markup component of LMP was $4.34 per MWh or 14.6 percent of the PJM real-time, load-weighted average LMP. May had the highest adjusted peak markup component, $8.23 per MWh, or 21.72 percent of the real-time peak hour load-weighted average LMP. Using the unadjusted cost offers, the highest markup of a marginal unit in the first six months of 2017 was $258.16 per MWh. There were 24 hours in the first six months of 2017 where the positive markup contribution to the PJM system wide, load-weighted, average LMP exceeded $44.20 per MWh.

  In the PJM Day-Ahead Energy Market, INCs, DECs and UTCs have zero markups. In the first six months of 2017, the adjusted markup component of LMP resulting from generation resources was $1.77 per MWh or 5.9 percent of the PJM day-ahead load-weighted average LMP. June had the highest adjusted markup component, $2.40 per MWh or 8.4 percent of the day-ahead load-weighted average LMP. Using the unadjusted cost offers, the highest markup of a marginal unit in the first six months of 2017 was $40.00 per MWh.

  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 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 -$0.40 per MWh in the first six months of 2016 and -$0.32 per MWh in the first six months of 2017. The difference between average day-ahead and real-time prices, by itself, is not a measure of the competitiveness or effectiveness of the Day-Ahead Energy Market.

Scarcity

- There were no shortage pricing events in the first six months of 2017. PJM implemented five minute shortage pricing on May 11, 2017.

Section 3 Recommendations

- The MMU recommends that the market rules should explicitly require that offers into the Day-Ahead Energy Market be competitive, where competitive is defined to be the short run marginal cost of the units. The short run marginal cost should reflect opportunity cost when and where appropriate. (Priority: Medium. First reported 2009. Status: Not adopted.)
- The MMU recommends that PJM require every market participant to make available at least one cost schedule with the same fuel type and parameters as that of their offered price schedule. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM require that the level of incremental costs includable in cost offers not exceed the unit's short run marginal cost. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that PJM require that all fuel cost policies be algorithmic, verifiable, and systematic. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that Manual 15 be replaced with a straightforward description of the components of cost offers based on short run marginal costs and the correct calculation of cost offers. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends removal of all use of the FERC System of Accounts in the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends the removal of all use of cyclic starting and peaking factors from the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends the removal of all labor costs from the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends changing the definition of the start heat input for combined cycles to include only the amount of fuel used from firing each combustion turbine in the combined cycle to the breaker close of each combustion turbine. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends the removal of nuclear fuel and nonfuel operations and maintenance costs that are not short run marginal costs from the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends revising the pumped hydro fuel cost calculation to include day-ahead and real-time power purchases. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends revisions to the calculation of energy market opportunity costs to incorporate all time based offer parameters and all limitations that impact the opportunity cost of generating unit output. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends removing the catastrophic designation for force majeure fuel supply limitations in Schedule 2. (Priority: Medium. First reported 2016. Status: Not adopted.)
- 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 the full MWh range of 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. First reported 2015. 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. First reported 2015. 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 and that this standard be applied to all technologies on a uniform basis. (Priority: Medium. First reported 2015. 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 nonperformance charges and the amount of uplift payments to those generators should reflect the flexibility goals of the capacity performance construct. (Priority: Medium. First reported 2015. Status: Not adopted.)
- 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 retain other existing rules that limit incentives to exercise market power. (Priority: High. First reported 1999. Status: Partially adopted, 1999.)
- The MMU recommends that PJM not allow nuclear generators which do not respond to prices or which only respond to manual instructions from the dispatcher to set the LMPs in the real-time market. (Priority: Low. First reported 2016. Status: Not adopted.)
- The MMU recommends that PJM document 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 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; the allowed duration of the violation; the use of constraint relaxation logic; and when the transmission penalty factors will be used to set the shadow price. (Priority: Medium. First reported 2015. Status: Not 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.[68] (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.[69] There is currently no PJM documentation in the tariff or manuals explaining how hubs are created and how their definitions are changed.[70] (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.

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

69 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.

70 The general definition of a hub can be found in the PJM.com Glossary <http://www.pjm.com/Glossary.aspx>.

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 remove nonspecific 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 2015. Status: Partially 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 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: Partially adopted, 2014.)
- 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 2014. Status: Adopted in full, 2014.)

Section 3 Conclusion

The MMU analyzed key elements of PJM energy market structure, participant conduct and market performance in the first six months of 2017, including aggregate supply and demand, concentration ratios, aggregate pivotal supplier results, local three pivotal supplier test results, offer capping, participation in demand response programs, loads and prices.

PJM average real-time cleared supply increased by 2,332 MW, 2.7 percent, and peak load increased by 5,979 MW, 4.4 percent, in the first six months of 2017 compared to the first six months of 2016. The relationship between supply and demand, regardless of the specific market, balanced by market concentration and the extent of pivotal suppliers, 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 although aggregate market power does exist for a significant number of hours. Market concentration levels remained in the unconcentrated range on average although there is high concentration in the peaking segment of the supply curve which adds to concerns about market power when market conditions are tight. Low average aggregate concentration does not mean that market power cannot be exercised. It is possible that market power can be exercised at times when individual suppliers or small groups of suppliers are pivotal even when the HHI level does not indicate that the market is highly concentrated. High markups for some units demonstrate the potential to exercise market power during high demand conditions. As demonstrated for the day-ahead market, it is possible to have pivotal suppliers in the aggregate market even when the HHI level is not in the highly concentrated range. The number of pivotal suppliers in the energy market is a more precise measure of structural market power than the HHI. The HHI is not a definitive measure of structural market power.

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 the first six months of 2017 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.[71] 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 market power 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.

Another issue with the application of market power mitigation in the Day-Ahead Energy Market and the Real-Time Energy Market when market sellers fail the TPS test is related to the definition of a competitive offer. A competitive offer is equal to short run marginal costs. The enforcement of market power mitigation rules is undermined if the definition of a competitive offer is not correct. The significance of competition metrics like markup is also undermined if the definition of a competitive offer is not correct. The definition of a competitive offer, as interpreted by PJM, is not currently correct. Some unit owners include costs that are not short run marginal costs in offers, including maintenance costs. This issue can be resolved by simple changes to the PJM Market Rules to incorporate a clear and accurate definition of short run marginal costs.

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

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

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. PJM implemented five minute scarcity pricing on May 11, 2017. 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 in 2014, 2015 or 2016. This is evidence of generally competitive behavior and competitive market outcomes, although the behavior of some participants during the high demand periods 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 the first six months of 2017.

Overview: Section 4, "Energy Uplift"

Energy Uplift Results

- **Energy Uplift Charges.** Total energy uplift charges decreased by $14.4 million, or 22.6 percent, in the first six months of 2017 compared to the first six months of 2016, from $63.9 million to $49.5 million.
- **Energy Uplift Charges Categories.** The decrease of $14.4 million in the first six months of 2017 is comprised of a $23.3 million decrease in day-ahead operating reserve charges, a $0.2 million increase in balancing operating reserve charges and a $8.7 million increase in reactive services charges.
- **Average Effective Operating Reserve Rates in the Eastern Region.** Day-ahead load paid $0.021 per MWh, real-time load paid $0.027 per MWh, a DEC paid $0.277 per MWh and an INC and any load, generation or interchange transaction deviation paid $0.256 per MWh.
- **Average Effective Operating Reserve Rates in the Western Region.** Day-ahead load paid $0.021 per MWh, real-time load paid $0.027 per MWh, a DEC paid $0.263 per MWh and an INC and any load, generation or interchange transaction deviation paid $0.242 per MWh.
- **Reactive Services Rates.** The PENELEC, BGE and Pepco control zones had the three highest local voltage support rates: $0.197, $0.114 and $0.112 per MWh.

Characteristics of Credits

- **Types of units.** Coal units received 83.2 percent of all day-ahead generator credits. Combustion turbines received 79.3 percent of all balancing generator credits. Combustion turbines and diesels received 54.6 percent of the lost opportunity cost credits.
- **Concentration of Energy Uplift Credits.** The top 10 units receiving energy uplift credits received 33.0 percent of all credits. The top 10 organizations received 79.1 percent of all credits. Concentration indexes for energy uplift categories classify them as highly concentrated. Day-ahead operating reserves HHI was 7633, balancing operating reserves HHI was 3532 and lost opportunity cost HHI was 5633.
- **Economic and Noneconomic Generation.** In the first six months of 2017, 85.2 percent of the day-ahead generation eligible for operating reserve credits was economic and 79.8 percent of the real-time generation eligible for operating reserve credits was economic.
- **Day-Ahead Unit Commitment for Reliability.** In the first six months of 2017, 1.1 percent of the total day-ahead generation MWh was scheduled as must run by PJM, of which 52.4 percent received energy uplift payments.

Geography of Charges and Credits

- In the first six months of 2017, 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, 4.7 percent by transactions at hubs and aggregates and 6.9 percent by interchange transactions at interfaces.
- Generators in the Eastern Region received 45.6 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.
- Generators in the Western Region received 51.8 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.
- External generators received 2.6 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.

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. First reported 2015. Status: Not adopted.)
- The MMU recommends that if PJM believes it appropriate to modify the LMP price setting logic, PJM initiate a stakeholder process to create transparent and consistent modifications to the rules and incorporate the modifications in the PJM tariff. (Priority: Medium. First Reported 2016. 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 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 four additional modifications to the energy lost opportunity cost calculations:
  - 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 for both the injection and the withdrawal sides of the UTC. (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 2012. Status: Not adopted. Stakeholder process.)
- The MMU recommends modifications to the calculation of lost opportunity costs credits paid to wind units. The lost opportunity costs credits paid to wind units should be based on the lesser of the desired output, the estimated output based on actual wind conditions and the capacity interconnection rights (CIRs). In addition, the MMU recommends that PJM allow and wind units submit CIRs that reflect the maximum

output wind units want to inject into the transmission system at any time. (Priority: Low. First reported 2012. Status: Not adopted.)

- The MMU recommends that PJM revise Manual 11 attachment C consistent with the tariff to limit compensation to offered costs. The Manual 11 attachment C procedure should describe the steps market participants should take to change the availability of cost-based energy offers that have been submitted day ahead. The MMU recommends that PJM eliminate the Manual 11 attachment C procedure with the implementation of hourly offers (ER16-372-000). (Priority: Medium. First reported 2016. 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 to make all market participants 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 2015.)
- 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: Partially adopted.)
- 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.)

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 incurred when LMP is greater than or equal to the incremental offer but does not cover start up and no load costs. Loss is defined to be receiving revenue less than the short run marginal costs incurred in order to generate energy. 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 short run 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.

Competitive market outcomes result from energy offers equal to short run marginal costs and that incorporate flexible operating parameters. But when PJM permits a unit to include inflexible operating parameters in its offer and pays uplift based on those inflexible parameters, there is an incentive for the unit to remain inflexible. The rules regarding operating parameters should be implemented in a way that creates incentives for flexible operations rather than inflexible operations. PJM has failed to hold coal, gas and oil steam turbines to the standard used for combined cycles, combustion turbines and diesels. The standard should be the maximum achievable flexibility, based on OEM standards. Applying a weaker standard to steam units effectively subsidizes inflexible units by paying them based on inflexible parameters that result from lack of investment and that could be made more flexible. The result both inflates uplift costs and suppresses energy prices.

In PJM, all energy payments to demand response resources are 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 have 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. Some uplift payments are the result of inflexible operating parameters included in offers by generating units. Operating parameters should reflect the flexibility of the benchmark new entrant unit in the PJM capacity market if the unit is to receive uplift payments from other market participants. 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.[72]

Under RPM, capacity obligations are annual. Base Residual Auctions (BRA) are held for Delivery Years that are three years in the future. Effective with the 2012/2013 Delivery Year, First, Second and Third Incremental Auctions (IA) are held for each Delivery Year.[73] 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.[74] 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.[75]

The 2020/2021 RPM Base Residual Auction was conducted in the first six months of 2017.

On June 9, 2015, FERC accepted changes to the PJM capacity market rules proposed in PJM's Capacity Performance (CP) filing.[76] 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 the 2016/2017 and 2017/2018 Delivery Years. 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.[77] 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. 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.

RPM prices are locational and may vary depending on transmission constraints.[78] 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

72 The terms *PJM Region*, *RTO Region* and *RTO* are synonymous in this report and include all capacity within the PJM footprint.
73 See 126 FERC ¶ 61,275 (2009) at P 86.
74 See Order in Docket No. ER10-366-000 (January 22, 2010).
75 See 126 FERC ¶ 61,275 (2009) at P 88.
76 See Docket No. ER15-623-000 (December 12, 2014) and 151 FERC ¶ 61,208 (2015).
77 See "PJM Manual 18: PJM Capacity Market," Revision 37 (April 27, 2017) at 9.
78 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.

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 the first six months of 2017, PJM installed capacity increased 678.1 MW or 0.4 percent, from 182,410.7 MW on January 1 to 183,088.8 MW on June 30. 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 June 30, 2017, 35.9 percent was coal; 36.3 percent was gas; 18.1 percent was nuclear; 3.7 percent was oil; 4.8 percent was hydroelectric; 0.6 percent was wind; 0.4 percent was solid waste; and 0.2 percent was solar.
- **Market Concentration.** In the 2020/2021 RPM Base Residual Auction all participants in the total PJM market as well as the LDA RPM markets failed the three pivotal supplier (TPS) test.[79] 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.[80] [81] [82]
- **Imports and Exports.** Of the 4,961.8 MW of imports in the 2020/2021 RPM Base Residual Auction, 3,997.2 MW cleared. Of the cleared imports, 1,671.2 MW (41.8 percent) were from MISO.
- **Demand-Side and Energy Efficiency Resources.** Capacity in the RPM load management programs was 10,117.8 MW for June 1, 2017, as a result of cleared capacity for Demand Resources and Energy Efficiency Resources in RPM Auctions for the 2017/2018 Delivery Year (13,793.0 MW) less replacement capacity from sources other than Demand Resources and Energy Efficiency (3,675.2 MW).

79 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).

80 See PJM. OATT Attachment DD § 6.5.

81 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.

82 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).

Market Conduct

- **2020/2021 RPM Base Residual Auction.** Of the 1,114 generation resources that submitted offers, the MMU calculated unit specific offer caps for 14 generation resources (1.3 percent).

Market Performance

- The 2020/2021 RPM Base Residual Auction was conducted in the first six months of 2017. The weighted average capacity price for the 2017/2018 Delivery Year is $141.16 per MW-day, including all RPM Auctions for the 2017/2018 Delivery Year held through the first three months of 2017. The weighted average capacity price for the 2018/2019 Delivery Year is $177.38, including all RPM Auctions for the 2018/2019 Delivery Year held through the first three months of 2017. The weighted average capacity price for the 2019/2020 Delivery Year is $114.30, including all RPM Auctions for the 2019/2020 Delivery Year held through the first three months of 2017. RPM net excess increased 1,329.5 MW from 5,855.9 MW on June 1, 2015, to 7,185.4 MW on June 1, 2016.
- For the 2016/2017 Delivery Year, RPM annual charges to load are $7.7 billion.
- The delivery year weighted average capacity price was $121.84 per MW-day in 2016/2017 and $141.16 per MW-day in 2017/2018.

Generator Performance

- **Forced Outage Rates.** The average PJM EFORd for the first six months of 2017 was 7.4 percent, an increase from 6.6 percent for the first six months of 2016.[83]

83 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 was downloaded from the PJM GADS database on July 26, 2017. 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.

- **Generator Performance Factors.** The PJM aggregate equivalent availability factor for the first six months of 2017 was 83.5 percent, an increase from 81.9 percent for the first six months of 2016.
- **Outages Deemed Outside Management Control (OMC).** In the first six months of 2017, 2.0 percent of forced outages were classified as OMC outages.

Section 5 Recommendations[84]

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.[85]

- The MMU recommends the extension of minimum offer price rule (MOPR) to all existing and proposed units in order to protect competition in the capacity market from external subsidies. (Priority: High. First reported 2016. Status: Not adopted.)
- 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.[86] [87] (Priority: High. First reported 2013. Status: Not adopted. Pending before FERC.)
- The MMU recommends that the test for determining modeled Locational Deliverability Areas (LDAs) 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 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.[88] [89] 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.[90] (Priority: High. First reported 2013. Status: Not adopted.)

84 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 52.
85 151 FERC ¶ 61,208 (June 9, 2015).
86 See also Comments of the Independent Market Monitor for PJM, Docket No. ER14-503-000 (December 20, 2013).
87 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2016," <http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Analysis_of_Replacement_Capacity_for_RPM_Commitments_06012007_to_06012016_20161227.pdf> (December 27, 2016).
88 See *PJM Interconnection, L.L.C.*, Docket No. ER12-513-000 (December 1, 2011) ("Triennial Review").
89 See the *2012 State of the Market Report for PJM*, Volume II, Section 6, Net Revenue.
90 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).

- The MMU recommends two changes to the RPM solution methodology related to make whole payments and the iterative reconfiguration of the VRR curve:
  - The MMU recommends changing the RPM solution methodology to explicitly incorporate the cost of make whole payments in the objective function. (Priority: Medium. First reported 2014. Status: Not adopted.)
  - The MMU also recommends changing the RPM solution methodology to define variables for the nesting relationships in the BRA optimization model directly rather than employing the current iterative approach, in order to improve the efficiency and stability. (Priority: Medium. First reported 2014. Status: Not adopted.)
- The MMU recommends the following changes with respect to capacity imports into PJM:
  - The MMU recommends that all capacity imports be required to be deliverable to PJM load prior to the relevant delivery year to ensure that they are as close to full substitutes for internal, physical capacity resources as possible. Pseudo ties alone are not adequate to ensure deliverability. (Priority: High. First reported 2016. Status: Not adopted.)
  - The MMU recommends that all costs incurred as a result of a pseudo tied unit be borne by the unit itself and included as appropriate in unit offers in the capacity market. (Priority: High. First reported 2016. Status: Not adopted.)
- The MMU recommends improvements to the performance incentive requirements of RPM:
  - 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 2009. Status: Not adopted. Pending before FERC.)
  - The MMU recommends that retroactive replacement capacity transactions not be permitted. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that treatment of costs in RMR filings be emphasized. Customers should bear all the incremental costs, including incremental investment costs, required by the RMR service that the unit owner would not have incurred if the unit owner had deactivated its unit as it proposed. Generation owners should bear all other costs. (Priority: Low. First reported 2010. Status: Not adopted.)
- The MMU recommends that the mitigation rules for Demand Resource and Energy Efficiency Resource offers be reevaluated and reviewed. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that Energy Efficiency Resources (EE) not be included on the supply side of the capacity market because PJM's load forecasts now account for future EE but did not when EE was first added to the capacity market. If EE is not included on the supply side, there is no reason to have an add back mechanism. If EE remains on the supply side, the implementation of the EE add back mechanism should be modified to ensure that market clearing prices are not affected. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that PJM reduce the number of incremental auctions to a single incremental auction held three months prior to the start of the delivery year and reevaluate the triggers for holding conditional incremental auctions. (Priority: Medium. First reported 2013. Modified Q1 2017. Status: Not adopted.)
- The MMU recommends that PJM release capacity in the incremental auction only in cases where the combination of quantities released and associated prices would increase the welfare of capacity market resource owners and load, including consideration of both capacity and energy market benefits in the determination of release quantities and prices. (Priority: Medium. First reported Q1, 2017. Status: Not adopted.)
- The MMU recommends that the notification requirement for deactivations be extended from 90 days prior to the date of deactivation to 12 months prior to the date of deactivation and that PJM and the MMU be provided 60 days rather than 30 days to complete their reliability and market power analyses. (Priority: Low. First reported 2012. Status: Partially adopted.)

- The MMU recommends clear, explicit and detailed rules that define the conditions under which PJM will and will not recall energy from PJM capacity resources and prohibit new energy exports from PJM capacity resources. The MMU recommends that those rules define the conditions under which PJM will purchase emergency energy while at the same time not recalling energy exports from PJM capacity resources. PJM has modified these rules, but they need additional clarification and operational details. (Priority: Low. First reported 2010. Status: Partially 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 2015.)
- 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 2012. Status: Adopted 2015.)
- The MMU recommends that all capacity imports have firm transmission to the PJM border acquired prior to offering in an RPM auction. (Priority: High. First reported 2014. Status: Adopted 2015.)
- 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 2015.)
- The MMU recommends that all resources importing capacity into PJM accept a must offer requirement. (Priority: High. First reported 2014. Status: Adopted 2015.)
- 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 2015.)
- 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 2015.)
- 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.[91] (Priority: Medium. First reported 2013. Status: Adopted 2015.)

Section 5 Conclusion

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

The MMU found serious market structure issues, measured by the three pivotal supplier test results, but no exercise of market power in the PJM Capacity Market in the first six months of 2017. Explicit market power mitigation rules in the RPM construct offset the underlying market structure issues in the PJM Capacity Market under RPM. The PJM capacity market results were competitive in the first six months of 2017.

The MMU has identified serious market design issues with RPM and the MMU has made specific recommendations to address those issues.[92] [93] [94] [95]

91 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).

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

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

94 See "Analysis of the 2018/2019 RPM Base Residual Auction Revised," <http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Analysis_of_the_20182019_RPM_Base_Residual_Auction_20160706.pdf> (July 6, 2016).

95 See "Analysis of the 2019/2020 RPM Base Residual Auction Revised," <http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Analysis_of_the_20192020_RPM_BRA_20160831-Revised.pdf> (August 31, 2016).

[96] In 2016 and 2017, the MMU prepared a number of RPM-related reports and testimony, shown in Table 5-2. The capacity performance modifications to the RPM construct have significantly improved the capacity market and addressed many of the issues identified by the MMU. The MMU will publish more detailed reports on the CP Auctions which include more specific issues and suggestions for improvements.

The issue of external subsidies emerged more fully in 2016. The subsidies are not part of the PJM market design but nonetheless threaten the foundations of the PJM capacity market as well as the competitiveness of PJM markets overall.

The Ohio subsidy proceedings and the Illinois ZEC subsidy proceeding all originate from the fact that competitive markets result in the exit of uneconomic and uncompetitive generating units. Regardless of the specific rationales offered by unit owners, the proposed solution for all such generating units has been to provide out of market subsidies in order to retain such units. The proposed solution in all cases ignores the opportunity cost of subsidizing uneconomic units, which is the displacement of resources and technologies that would otherwise be economic. These subsidies are not accurately characterized as state subsidies. These subsidies were all requested by the owners of specific uneconomic generating units in order to improve the profitability of those specific units. These subsidies were not requested to accomplish broader social goals. Broader social goals can all be met with market based mechanisms available to all market participants on a competitive basis and without discrimination.

Subsidies are contagious. Competition in the markets could be replaced by competition to receive subsidies. Similar threats to competitive markets are being discussed by unit owners in other states and the potentially precedential nature of these actions enhances the urgency of creating an effective rule to maintain competitive markets by modifying market rules to address these subsidies. Fortunately, this can be accomplished quickly by expanding the coverage of an existing rule that already reflects stakeholder compromises.

PJM markets have no protection against this emergent threat. Accurate signals for entry and exit are necessary for well functioning and competitive markets. Competitive investors rely on accurate signals to make decisions. The current MOPR only addresses subsidies for new entry. The current subsidies demonstrate that the markets need protection against subsidized, noncompetitive offers from existing as well as new resources. The MOPR should be expanded to address subsidies for existing units, and this should be done expeditiously. This issue will not become moot unless and until the MOPR is reformed. Action is needed to correct the MOPR immediately. An existing unit MOPR is the best means to defend the PJM markets from the threat posed by subsidies intended to forestall retirement of financially distressed assets. The role of subsidies to renewables should also be clearly defined and be incorporated in this rule.

While the existing unit MOPR would protect markets in the short run, the underlying issues that have resulted in the pressure on markets should also be examined. Unit owners are seeking subsidies because gas prices are low resulting in low energy market margins and because flaws in the PJM capacity design have led to very substantial price suppression over the past 10 years.

To the extent that there are shared broader goals related to PJM markets, they should also be addressed, but this can happen with a slightly longer lead time. If a shared goal is to reduce carbon output, a price on carbon is the market based solution. If a shared goal is increased renewables in addition to their carbon attributes, a common approach to RECs would be a market based solution. Fuel diversity has also been mentioned as an issue. Current fuel diversity is higher than ever in PJM. If there is an issue, the real issue is fuel security and not fuel diversity. Significant reliance on specific fuels, including nuclear, coal and gas means that markets are at risk from a significant disruption in any one fuel. If fuel security for gas is a concern, a number of issues should be considered including the reliability of the pipelines, the compatibility of the gas pipeline and the merchant generator business models, the degree to which

96 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2016," <http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Analysis_of_Replacement_Capacity_for_RPM_Commitments_06012007_to_06012016_20161227.pdf> (December 27, 2016).

electric generators have truly firm gas service and the need for a gas RTO to help ensure reliability.

As a result of the fact that demand side resources have contributed to price suppression in PJM capacity markets, the place of demand side in PJM should be reexamined. There are ways to ensure and enhance the vibrancy of demand side without negatively affecting markets for generation. There are other price formation issues in the capacity market that should also be examined and addressed.

Overview: Section 6, "Demand Response"

Overview

- **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 and pre-emergency programs are part of the capacity market program which includes both capacity payments and associated energy revenues when the capacity is called on to respond.[97] In the first six months of 2017, the emergency program accounted for 98.7 percent of all revenue received by demand response providers, the economic program for 0.4 percent, synchronized reserve for 0.6 percent and the regulation market for 0.3 percent. Total emergency revenue decreased by $178.1 million, 43.1 percent, from $413.6 million in the first six months of 2016 to $235.5 million in the first six months of 2017. Capacity market revenue, which comprised 100.0 percent of the emergency demand response program in the first six months of 2017, decreased by $178.1 million, 43.1 percent, from $413.6 million in the first six months of 2016 to $235.5 million in the first six months of 2017.[98]

  Economic program revenue decreased by $0.4 million, from $1.4 million in the first six months of 2016 to $0.9 million in the first six months of 2017, a 32.2 percent decrease.[99] Synchronized reserve revenue decreased by $0.5 million, from $1.9 million in the first six months of 2016 to $0.9 million in the first six months of 2017, a 24.1 percent decrease. Regulation revenue increased by $0.4 million, from $0.4 million in the first six months of 2016 to $0.8 million in the first six months of 2017, a 94.5 percent increase.

  Total demand response revenue decreased by $178.6 million, from $417.3 million in the first six months of 2016 to $238.7 million in the first six months of 2017, a 42.8 percent decrease. Not all DR activities in the first six months of 2017 had been reported to PJM at the time of this report.

  Emergency and Economic 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.[100]

- **Demand Response Market Concentration.** The ownership of economic demand response was highly concentrated in the first six months of 2016 and 2017. The HHI for economic demand response reductions increased from 7658 in the first six months of 2016 to 7752 in the first six months of 2017. The ownership of emergency demand response was moderately concentrated in 2017. The HHI for emergency demand response registrations was 1433 for the 2017/2018 Delivery Year. In the 2017/2018 Delivery Year, the four largest companies contributed 69.6 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, but only if the subzone is defined at least one day before it is dispatched and only until PJM removes the definition of the subzone. More locational dispatch of demand resources

97 Throughout this document, emergency demand response refers to both emergency and pre-emergency demand response.

98 The total credits and MWh numbers for demand resources were calculated as of April 10, 2017 and may change as a result of continued PJM billing updates.

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

100 "PJM Manual 28: Operating Agreement Accounting," Rev. 75 (November 18, 2016) at 77.

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.

Section 6 Recommendations

The MMU recognizes that PJM incorporated some of the recommendations related to Demand Response in the Capacity Performance filing. The status of each recommendation reflects the status at June 30, 2017.

- 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 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 treated as an economic resource, responding to economic price signals like other capacity resources and not an emergency program responding only after an emergency is called, and not triggering the definition of a PJM emergency and not triggering a Performance Assessment Hour under the new PJM Capacity Market rules. (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.[101] (Priority: High. First reported 2013. Status: Not 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 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 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.[102] (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

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

102 See ISO-NE Tariff, Section III, Market Rule 1, Appendix E1 and Appendix E2, "Demand Response," <http://www.iso-ne.com/regulatory/tariff/sect_3/mr1_append-e.pdf>. (Accessed June 29, 2016) 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.

compliance for the base and capacity performance products. (Priority: Medium. First reported 2013. Status: Not adopted.)

- 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. First reported 2015. 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 2015. Status: Not adopted.)
- The MMU recommends that PJM not remove any defined subzone and maintain a public record of all created and removed subzones. (Priority: Low. First reported 2016. 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. (Priority: High. First reported 2011. Status: Partially adopted.[103])
- 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 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 capping the baseline for measuring compliance under GLD, for the limited summer product, at the customers' PLC. (Priority: High. First reported 2010. Status: Adopted 2015.)
- The MMU recommends that demand resources whose technology type (load drop method) is designated as "Other" explicitly record the technology type. (Priority: Low. First reported 2013. Status: Adopted, 2014.)

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.

103 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.

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 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 (PAH) will be measured on an hourly basis.

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. 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 MMU.

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

- Energy net revenues are significantly affected by energy prices and fuel prices. Energy prices and fuel prices were higher in the first six months of 2017 than in the first six months of 2016. Gas prices increased more than LMP and CTs and CCs ran fewer hours with lower margins as a result. Coal prices increased more than LMP but less than gas prices and CPs ran for more hours in the first six months of 2017 than in the first six months of 2016 and with higher margins.
- In the first six months of 2017, average energy market net revenues decreased by 59 percent for a new CT, 26 percent for a new CC, and 58 percent for a new DS compared to the first six months of 2016. Average energy market net revenues increased by 16 percent for a new CP, 18 percent for a new nuclear plant, 26 percent for a new wind installation, and one percent for a new solar installation compared to the first six months of 2016.

Historical New Entrant CT and CC Revenue Adequacy

Total unit net revenues include energy and capacity revenues. Analysis of the total unit revenues of theoretical new entrant CTs and CCs for three representative locations shows that units that entered the PJM markets in 2007 have not covered their total costs, including the return on and of capital, on a cumulative basis through June 30, 2017. The analysis also shows that theoretical new entrant CTs and CCs that entered the PJM markets in 2012 have covered their total costs on a cumulative basis in the eastern PSEG and BGE zones but have not covered total costs in the western ComEd Zone. Energy market revenues were not sufficient to cover total costs in any scenario except the new entrant CC unit that went into operation in 2012 in BGE, which demonstrates the critical role of capacity market revenue in covering total costs.

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.

Unlike cost of service regulation, markets do not guarantee that units will cover their costs. New CT and CC units that began operation in 2007 have not covered their total costs from energy market and capacity market revenues through June 30, 2017 in the ComEd Zone, in the PSEG Zone and in the BGE Zone. New CT and CC units that began operation on June 1, 2012, have covered or more than covered their total costs in the PSEG Zone and the BGE Zone through June 30, 2017, and have not covered their total costs in the ComEd Zone through June 30, 2017.

Overview: Section 8, "Environmental and Renewables"

Federal Environmental Regulation

- **EPA Mercury and Air Toxics Standards Rule.** The U.S. Environmental Protection Agency's (EPA) Mercury and Air Toxics Standards rule (MATS) 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.[104] The future of MATS is currently uncertain. The U.S. Supreme Court ruled in 2015 that the EPA acted "unreasonably when it deemed cost irrelevant to the decision to regulate power plants."[105] The EPA performed a cost review and made the required determination on cost in a supplemental finding.[106] In a case now pending before the U.S. Court of Appeals for the District of Columbia Circuit, the supplemental finding is under review.[107] On April 28, 2017, the Court granted the EPA's request to postpone scheduled oral argument "to allow the new Administration adequate time to review the Supplemental Finding to determine whether it will be reconsidered."[108]

- **Air Quality Standards (NO_X and SO_2 Emissions).** The CAA requires each state to attain and maintain compliance with fine particulate matter (PM) and ozone national ambient air quality standards (NAAQS). The CAA also requires that each state prohibit emissions that significantly interfere with the ability of another state to meet NAAQS.[109] In January 2016, the EPA began the implementation of the Cross-State Air Pollution Rule (CSAPR) to address this issue through an interstate emissions trading regime.[110] As of January 1, 2017, CSAPR's Phase 2 emissions budgets and assurance provisions apply.

- **National Emission Standards for Reciprocating Internal Combustion Engines.** On May 1, 2015, the U.S. Court of Appeals for the District of Columbia Circuit reversed the portion of the final rule exempting 100 hours of run time for certain stationary reciprocating internal combustion engines (RICE) participating in emergency demand response programs.[111] On May 3, 2016, the Court issued a mandate to implement its May 1, 2015, order. The provisions that allowed RICE participating in emergency demand response programs to operate for additional hours have been eliminated.[112] Zero hours are exempt.[113] As a result, the national emissions standards uniformly apply to all RICE.[114] All RICE are allowed to operate

104 *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).

105 135 S. Ct. 2699, 2712 (2015).

106 *See Supplemental Finding That It Is Appropriate and Necessary to Regulate Hazardous Air Pollutants From Coal- and Oil-Fired Electric Utility Steam Generating Units*, EPA Docket No. EPA-HQ-OAR-2009-0234; *see also* White Stallion Energy Center, LLC v EPA, Slip Op. No. 12-1100 (D.C. Cir. 2015) (per curiam).

107 *See* Case No. 16-1127, et al.

108 Respondent EPA's Motion to Continue Oral Argument, Case No. 16-1127, et al. (April 18, 2017) at 1.

109 CAA § 110(a)(2)(D)(i)(I).

110 Federal Implementation Plans: Interstate Transport of Fine Particulate Matter and Ozone and Correction of SIP Approvals, Final Rule, Docket No. EPA-HQ-OAR-2009-0491, 76 Fed. Reg. 48208 (August 8, 2011) ("CSAPR").

111 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).

112 EPA, Memorandum, Peter Tsirigotis Guidance on Vacatur of RICE NESHAP and NSPS Provisions for Emergency Engines (April 15, 2016).

113 *Id.*

114 *Id.*

during emergencies, including declared Energy Emergency Alert Level 2 or five percent voltage/frequency deviations.[115]

- **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).[116] 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 of the rule that will prevent its taking effect until judicial review is completed.[117] The future of the Clean Power Plan is currently uncertain. The new administration is reviewing the Clean Power Plan and related rules and agency actions, and has indicated the possibility of suspension, revision or rescission of such rules and actions.[118] On April 28, 2017, the U.S. Court of Appeals for the District of Columbia Circuit issued orders granting a motion of the EPA to hold in abeyance for 60 days pending cases challenging the Clean Power Plan, and further directed the filing of briefs on whether these cases "should be remanded to the agency rather than held in abeyance."[119]

- **Cooling Water Intakes.** An EPA rule implementing Section 316(b) of the Clean Water Act (CWA) requires that cooling water intake structures reflect the best technology available for minimizing adverse environmental impacts.[120] 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.

  On June 17, 2017, the EPA issued a rulemaking to rescind the definition of "Waters of the United States" (WOTUS) proposed in the 2015 Clean Water Rule.[121] The rule would avoid the potential implementation of a broader definition of WOTUS included in the 2015 rule that was never implemented as the result of a stay issued by a reviewing Court.[122] The rule would restore the pre 2015 version of the rule to the code, which remains in effect as a result of the stay.

- **Waste Disposal.** On December 19, 2014, the EPA issued its Coal Combustion Residuals rule (CCRR), effective October 19, 2015. The rule sets nonbinding criteria for coal ash disposal facilities.

State Environmental Regulation

- **NJ High Electric Demand Day (HEDD) Rule.** A New Jersey rule that imposes operational restrictions and emissions control requirements on units responsible for significant NO_X emissions on high electric demand days (HEDD).[123] 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.[124]

- **Illinois Air Quality Standards (NO_X, SO_2 and Hg).** The State of Illinois has its own standards for NO_X, SO_2 and Hg (mercury) known as Multi-Pollutant Standards (MPS) and Combined Pollutants Standards (CPS) that are more stringent and take effect earlier than comparable Federal regulations, such as the EPA MATS rule.[125]

- **Regional Greenhouse Gas Initiative (RGGI).** The Regional Greenhouse Gas Initiative (RGGI) is a CO_2 emissions cap and trade agreement among Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont that applies to power generation facilities. The auction price in the June 7, 2017, auction for the 2015–2017 compliance period was \$2.53 per ton. The clearing price is equivalent to a price of \$2.79 per metric tonne, the unit used in other carbon markets. The price decreased from \$4.53 per ton from June 1, 2016, by \$2.00 per ton, or 44.2 percent, to \$2.53 per ton for June 7, 2017.

115 See 40 CFR §§ 60.4211(f)(2)(ii)–(iii), 60.4243(d)(2)(ii)–(iii), and 63.6640(f)(2)(ii)–(iii) (Declared Energy Emergency Alert Level 2 or 5 percent voltage/frequency deviations); 0 CFR §§ 60.4211(f)(1), 60.4243(d)(1), and 63.6640(f)(1) ("There is no time limit on the use of emergency stationary ICE in emergency situations."); 40 §§ CFR 60.4211(f)(3), 60.4243(d)(3), 63.6640(f)(3)–(4).

116 *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."

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

118 Executive Order: Promoting Energy Independence and Economic Growth, Sec. 4 (March 28, 2017), which can be accessed at: <https://www.whitehouse.gov/the-press-office/2017/03/28/presidential-executive-order-promoting-energy-independence-and-economi-1>.

119 See West Virginia v. EPA, No. 15-1363 (D.C. Cir.); North Dakota v. EPA, No. 15-1381 (D.C. Cir.).

120 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).

121 80 Fed. Reg. 37054 (June 29, 2015).

122 The stay was issued by the U.S. Court of Appeals for the Sixth Circuit on October 9, 2015.

123 N.J.A.C. § 7:27-19.

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

125 35 Ill. Admin. Code §§ 225.233 (Multi-Pollutant Standard (MPS)), 224.295 (Combined Pollutant Standard: Emissions Standards for NO_X and SO_2 (CPS)).

State Renewable Portfolio Standards

Many states in PJM have enacted legislation to require that a defined percentage of retail suppliers' load be served by renewable resources, for which definitions vary. These are typically known as renewable portfolio standards, or RPS. As of June 30, 2017, Delaware, Illinois, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, and Washington, DC had renewable portfolio standards. Virginia and Indiana had voluntary renewable portfolio standards. Kentucky and Tennessee did not have renewable portfolio standards. West Virginia had a voluntary standard, but the state legislature repealed their renewable portfolio standard effective February 3, 2015.[126]

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. As a result of environmental regulations and agreements to limit emissions, many PJM units burning fossil fuels have installed emission control technology. On March 31, 2017, 92.8 percent of coal steam MW had some type of FGD (flue-gas desulfurization) technology to reduce SO_2 emissions, while 99.5 percent of coal steam MW had some type of particulate control, and 93.5 percent of fossil fuel fired capacity in PJM had NO_X emission control technology.

Section 8 Recommendations

- The MMU recommends that renewable energy credit markets based on state renewable portfolio standards be brought into PJM markets as they are an increasingly important component of the wholesale energy market. (Priority: Medium. First reported 2010. Status: Not adopted.)

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. The extension of the RPS concept to include nuclear power as a zero emissions source in order to provide subsidies to nuclear power will increase this impact. Renewable energy credit (REC) 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.[127]

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 same is true for nuclear power credits, ZECs (zero emissions credits). 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 in some cases the existence of these resources 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, clearing quantities and markets are not publicly available for all PJM states. RECs do not need to be consumed during the year of production which creates multiple prices for a REC based on the year of origination. 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. It would be preferable to have a single, transparent market for RECs operated by PJM that would meet the standards and requirements of all states in the PJM footprint including those with no RPS. This would provide better information for market participants about supply and demand and prices and contribute to a more efficient and competitive market and to better price formation. This could also facilitate entry by qualifying renewable resources by reducing the risks associated with

126 See Enr. Com. Sub. For H. B. No. 2001.

127 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.").

lack of transparent market data. This would be a significant improvement even if some unusual or unique types of RECs remained outside this market.

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 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. If there is a social decision to limit carbon output, a carbon price would be the most efficient way to implement that decision. It would also be an alternative to specific subsidies to individual nuclear power plants and instead provide a market signal to which any resource could respond. 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. The provision of subsidies to individual units creates a discriminatory regime that is not consistent with competition.

Overview: Section 9, "Interchange Transactions"

Interchange Transaction Activity

- **Aggregate Imports and Exports in the Real-Time Energy Market.** In the first six months of 2017, PJM was a monthly net exporter of energy in the Real-Time Energy Market in all months.[128] In the first six months of 2017, the real-time net interchange of -10,721.4 GWh was lower than the net interchange of 4,763.3 GWh in the first six months of 2016.
- **Aggregate Imports and Exports in the Day-Ahead Energy Market.** In the first six months of 2017, PJM was a monthly net exporter of energy in the Day-Ahead Energy Market in all months. In the first six months of 2017, the total day-ahead net interchange of -8,641.8 GWh was lower than net interchange of 76.9 GWh in the first six months of 2016.
- **Aggregate Imports and Exports in the Day-Ahead and the Real-Time Energy Market.** In the first six months of 2017, gross imports in the Day-Ahead Energy Market were 169.3 percent of gross imports in the Real-Time Energy Market (118.1 percent in the first six months of 2016). In the first six months of 2017, gross exports in the Day-Ahead Energy Market were 124.7 percent of the gross exports in the Real-Time Energy Market (151.6 percent in the first six months of 2016).
- **Interface Imports and Exports in the Real-Time Energy Market.** In the first six months of 2017, there were net scheduled exports at 10 of PJM's 20 interfaces in the Real-Time Energy Market.
- **Interface Pricing Point Imports and Exports in the Real-Time Energy Market.** In the first six months of 2017, 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.[129]
- Interface Imports and Exports in the Day-Ahead Energy Market. In the first six months of 2017, there were net scheduled exports at 11 of PJM's 20 interfaces in the Day-Ahead Energy Market.
- Interface Pricing Point Imports and Exports in the Day-Ahead Energy Market. In the first six months of 2017, 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 the first six months of 2017, up to congestion transactions were net exports at four of PJM's 19 interface pricing points eligible for day-ahead transactions in the Day-Ahead Market.
- Inadvertent Interchange. In the first six months of 2017, net scheduled interchange was -10,721 GWh and net actual interchange was -10,739

128 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.

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

GWh, a difference of 18 GWh. In the first six months of 2016, the difference was 892 GWh. This difference is inadvertent interchange.

- Loop Flows. In the first six months of 2017, the Wisconsin Energy Corporation (WEC) interface had the largest loop flows of any interface with -1,037 GWh of net scheduled interchange and 3,747 GWh of net actual interchange, a difference of 4,783 GWh. In the first six months of 2017, the SouthIMP interface pricing point had the largest loop flows of any interface pricing point with 5,600 GWh of net scheduled interchange and 12,113 GWh of net actual interchange, a difference of 6,513 GWh.

Interactions with Bordering Areas

PJM Interface Pricing with Organized Markets

- **PJM and MISO Interface Prices.** In the first six months of 2017, 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 59.8 percent of the hours.
- **PJM and New York ISO Interface Prices.** In the first six months of 2017, 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 51.9 percent of the hours.
- **Neptune Underwater Transmission Line to Long Island, New York.** In the first six months of 2017, 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 56.5 percent of the hours.
- **Linden Variable Frequency Transformer (VFT) Facility.** In the first six months of 2017, 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 52.0 percent of the hours.
- **Hudson DC Line.** In the first six months of 2017, 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 0.1 percent of the hours.[130]

Interchange Transaction Issues

- **PJM Transmission Loading Relief Procedures (TLRs).** PJM issued three TLRs of level 3a or higher in the first six months of 2017, compared to eight such TLRs issued in the first six months of 2016.
- **Up to congestion.** There was an increase in up to congestion volume starting in December 2015, coincident with the expiration of the fifteen month limit on the payment of prior uplift charges.[131] The average number of up to congestion bids submitted in the Day-Ahead Energy Market increased by 14.8 percent, from 141,248 bids per day in the first six months of 2016 to 162,213 bids per day in the first six months of 2017. The average cleared volume of up to congestion bids submitted in the Day-Ahead Energy Market increased by 12.8 percent, from 829,838 MWh per day in the first six months of 2016, to 936,340 MWh per day in the first six months of 2017.
- **45 Minute Schedule Duration Rule.** Effective May 19, 2014, PJM removed the 45 minute scheduling duration rule in response to FERC Order No. 764.[132] [133] 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.[134]

Section 9 Recommendations

- The MMU recommends that PJM implement rules to prevent sham scheduling. The MMU recommends that PJM apply after the fact market settlement adjustments to identified sham scheduling segments to ensure

130 The Hudson Line was out of service for all hours in the first six months of 2017. In the first six months of 2017, there were five hours with less than 1 MW of unscheduled flow across the Hudson Line.
131 148 FERC ¶ 61,144 (2014).*Order Instituting Section 206 Proceeding and Establishing Procedures.* 16 U.S.C. § 824e.
132 *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).
133 *See* Letter Order, Docket No. ER14-381-000 (June 30, 2014).
134 *See* joint statement of PJM and the MMU re Interchange Scheduling issued July 29, 2014, at: <http://www.monitoringanalytics.com/reports/Market_Messages/Messages/PJM_IMM_Statement_on_Interchange_Scheduling_20140729.pdf>.

that market participants cannot benefit from sham scheduling. (Priority: High. First reported 2012. Status: Not adopted. Stakeholder process.)

- 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 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 end the practice of maintaining outdated definitions of interface pricing points, 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: Medium. First reported 2013. Status: Not adopted.)
- 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 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 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 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 nonfirm 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 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 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. First reported 2015. Status: Not adopted.)
- The MMU recommends that the emergency interchange cap be replaced with a market based solution. (Priority: Low. First reported 2015. 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 2014. Status: Adopted partially, 2015.)

- 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 2017.)

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 nonmarket areas, all electricity transactions are part of a single energy market. Nonetheless, there are significant differences between market and nonmarket 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. Nonmarket areas do not include these features. The market areas are extremely transparent and the nonmarket 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 outcomes 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 nonsynchronized, that can provide energy within 10 minutes. Primary reserve is PJM's implementation of the NERC 15-minute contingency reserve requirement.[135]

Market Structure

- **Supply.** Primary reserve is satisfied by both synchronized reserve (generation or demand response currently synchronized to the grid and available within 10 minutes), and nonsynchronized reserve (generation currently off-line but available to start and provide energy within 10 minutes).
- **Demand.** The PJM primary reserve requirement is 150 percent of the largest contingency. From January 8, 2015, through May 10, 2017, the primary reserve requirement in the RTO Zone was 2,175 MW of which 1,700 MW was required to be available within the Mid-Atlantic Dominion (MAD) Subzone. As of May 10, 2017, the MAD requirement was raised to 2,175 MW. Temporary adjustments to the primary reserve requirement can occur when grid maintenance or outages change the largest contingency. In the first six months of 2017, the average primary reserve requirement was 2,183.3 MW in the RTO Zone and 1,769.9 MW in MAD.

Tier 1 Synchronized Reserve

Synchronized reserve is provided by generators or demand response resources synchronized to the grid and capable of increasing output or decreasing load within 10 minutes. Synchronized reserve consists of tier 1 and tier 2 synchronized reserves.

Tier 1 synchronized reserve is part of primary reserve and is the capability of online resources following economic dispatch to ramp up in 10 minutes from their current output in response to a synchronized reserve event. There is no formal market for tier 1 synchronized reserve.

135 See PJM. "Manual 10: Pre-Scheduling Operations," Revision. 35 (January 1, 2017), p. 24.

- **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 the first six months of 2017, there was an average hourly supply of 1,263.1 MW of tier 1 for the RTO Synchronized Reserve Zone, and an average hourly supply of 1,123.6 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 per MW. This is the Synchronized Energy 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 nonsynchronized reserve market clearing price.

  Of the Degree of Generator Performance (DGP) adjusted tier 1 synchronized reserve MW estimated at market clearing, 68.8 percent actually responded during the four synchronized reserve events with duration of 10 minutes or longer in the first six months of 2017.
- **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. This requirement was unnecessary and inconsistent with efficient markets. 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 $89,719,045 to tier 1 resources in 2014, $34,397,441 in 2015, $4,948,084 in 2016, and $795,233 in the first six months of 2017.

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, that have penalties for failure to respond, 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 uses 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 the first six months of 2017, the supply of offered and eligible tier 2 synchronized reserve was 23,877.2 MW in the RTO Zone of which 6,772.2 MW (including 1,504.1 MW of DSR) was located in the MAD 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 hourly average required tier 2 synchronized reserve was 351.3 MW in the MAD Subzone and 602.9 MW in the RTO.
- **Market Concentration.** Both the Mid-Atlantic Dominion Subzone Tier 2 Synchronized Reserve Market and the RTO Synchronized Reserve Zone Market were characterized by structural market power in the first six months of 2017.

  In the first six months of 2017, the weighted average HHI for tier 2 synchronized reserve in the Mid-Atlantic Dominion Subzone was 5609, which is classified as highly concentrated. The MMU calculates that the three pivotal supplier test in the Mid-Atlantic Dominion Subzone would have been failed in 70.9 percent of hours.

In the first six months of 2017, the weighted average HHI for cleared tier 2 synchronized reserve in the RTO Synchronized Reserve Zone was 6765, which is classified as highly concentrated. The MMU calculates that the three pivotal supplier test in the RTO Synchronized Reserve Zone would have been failed in 61.6 percent of hours.

Market Conduct

- **Offers.** There is a must offer requirement for tier 2 synchronized reserve. All nonemergency generation capacity resources are required to submit a daily offer for tier 2 synchronized reserve, unless the unit type is exempt. 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. There has been less than complete compliance with the tier 2 synchronized reserve must offer requirement.

Market Performance

- **Price.** The weighted average price for tier 2 synchronized reserve for all cleared hours in the Mid-Atlantic Dominion (MAD) Subzone was $2.34 per MW in the first six months of 2017, a decrease of $2.16 from the first six months of 2016.

  The weighted average price for tier 2 synchronized reserve for all cleared hours in the RTO Synchronized Reserve Zone was $2.34 per MW in the first six months of 2017, a decrease of $2.11 from the first six months of 2016.

Nonsynchronized Reserve Market

Nonsynchronized reserve is part of primary reserve and includes the RTO Reserve Zone and the Mid-Atlantic Dominion Reserve Subzone (MAD). Nonsynchronized reserve is comprised of nonemergency energy resources not currently synchronized to the grid that can provide energy within 10 minutes. Nonsynchronized reserve is available to fill the primary reserve requirement above the synchronized reserve requirement. Generation owners do not submit supply offers. PJM defines the demand curve for nonsynchronized reserve and PJM defines the supply curve based on nonemergency generation resources that are available to provide energy and can start in 10 minutes or less (based on offer parameters), and on the resource opportunity costs calculated by PJM.

Market Structure

- **Supply.** In the first six months of 2017, the average hourly supply of eligible nonsynchronized reserve was 2,288.1 MW in the RTO Zone and 1,951.5 MW in MAD Subzone.
- **Demand.** Demand for nonsynchronized reserve equals the primary reserve requirement minus the tier 1 synchronized reserve estimate and minus the scheduled tier 2 synchronized reserve.[136] In the RTO Zone, the market cleared an hourly average of 1,293.5 MW of nonsynchronized reserve in the first six months of 2017. The MAD Subzone cleared an average of 903.9 MW in the first six months of 2017.
- **Market Concentration.** In the first six months of 2017, the weighted average HHI for cleared nonsynchronized reserve in the MAD Subzone was 3806 which is classified as highly concentrated. In the RTO Zone the weighted average HHI was 3799, which is also highly concentrated. The MMU calculates that the three pivotal supplier test would have been failed in 42.0 percent of hours in the MAD Subzone and zero hours in the RTO Zone.

Market Conduct

- **Offers.** Generation owners do not submit supply offers. Nonemergency generation resources that are available to provide energy and can start in 10 minutes or less are considered available for nonsynchronized reserves by the market solution software. PJM calculates the associated offer prices based on PJM calculations of resource specific opportunity costs.

136 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Revision 90 (July 27, 2017), p. 81. "Because Synchronized Reserve may be utilized to meet the Primary Reserve requirement, there is no explicit requirement for non-synchronized reserves. "

Market Performance

- **Price.** The nonsynchronized reserve price is determined by the opportunity cost of the marginal nonsynchronized reserve unit. The nonsynchronized reserve weighted average price for all hours in the RTO Reserve Zone was $0.10 per MW in the first six months of 2017 and was $0.00 in 97.9 percent of hours. The MAD Subzone cleared at a separate price from the RTO Zone in 41 hours in the first six months of 2017, with a weighted average price of $0.10.

Secondary Reserve

There is no NERC standard for secondary reserve. PJM defines secondary reserve as reserves (online or offline available for dispatch) that can be converted to energy in 30 minutes. PJM defines a secondary reserve requirement but does not have a goal to maintain this reserve requirement in real time.

PJM maintains a day-ahead, offer based market for 30-minute day-ahead secondary reserve. The Day-Ahead Scheduling Reserve Market (DASR) has no performance obligations except that a unit which clears the DASR market may not be on an outage in real time.[137] If DASR units are on an outage in real time, the DASR payment is not made.

Market Structure

- **Supply.** The DASR Market is a must offer market. Any resources that do not make an offer have their offer set to $0.00 per MW. DASR is calculated by the day-ahead market solution as the lesser of the thirty minute energy ramp rate or the economic maximum MW minus the day-ahead dispatch point for all online units. In the first six months of 2017, the average available hourly DASR was 35,679.8 MW.
- **Demand.** The DASR requirement for 2017 is 5.52 percent of peak load forecast, down from 5.70 percent in 2016. The average DASR MW purchased was 4,037.2 MW per hour in the first six months of 2017, compared to the 5,501.0 MW per hour in the same time period of 2016.
- **Concentration.** In the first six months of 2017, the MMU estimates that the DASR Market would have failed the three pivotal supplier test in 18.7 percent of hours.

Market Conduct

- **Withholding.** Economic withholding remains an issue in the DASR Market. The direct marginal cost of providing DASR is zero. PJM calculates the opportunity cost for each resource. All offers by resource owners greater than zero constitute economic withholding. In the first six months of 2017, a daily average of 39.6 percent of units offered above $0.00. A daily average of 14.4 percent of units offered above $5.
- **DR.** Demand resources are eligible to participate in the DASR Market. Some demand resources have entered offers for DASR. No demand resources cleared the DASR market in the first six months of 2017.

Market Performance

- **Price.** In the first six months of 2017, the weighted average DASR price for all hours when the DASRMCP was above $0.00 was $2.18.

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 one of two regulation signals, RegA or RegD. PJM jointly optimizes regulation with synchronized reserve and energy to provide all three products at least cost. The PJM regulation market design includes three clearing price components: capability; performance; and opportunity cost. The RegA signal is designed for energy unlimited resources with physically constrained ramp ability. The RegD signal is designed for energy limited resources with fast ramp rates. In the Regulation Market RegD MW are converted to effective MW using a marginal rate of substitution (MRTS), called a marginal benefit function (MBF). Correctly implemented, the MBF would be the marginal rate of technical substitution (MRTS) between RegA and RegD, holding the level of regulation service constant. The current market design is critically flawed as it has not properly implemented the MBF as an MRTS between RegA and

137 See PJM, "Manual 11: Energy & Ancillary Services Market Operations," Revision 90 (July 27, 2017), p. 172 §11.1.

RegD resource MW and the MBF has not been consistently applied in the optimization, clearing and settlement of the Regulation Market.

Market Structure

- **Supply.** In the first six months of 2017, the average hourly eligible supply of regulation for nonramp hours was 1,145.2 performance adjusted MW (848.1 effective MW).[138] This was a decrease of 47.7 performance adjusted MW (an increase of 14.1 effective MW) from the first six months of 2016, when the average hourly eligible supply of regulation for nonramp hours was 1,192.9 performance adjusted MW (834.0 effective MW). In the first six months of 2017, the average hourly eligible supply of regulation for ramp hours was 1,418.9 performance adjusted MW (1,160.7 effective MW). This was an increase of 226.8 performance adjusted MW (216.3 effective MW) from the first six months of 2016, when the average hourly eligible supply of regulation was 1,192.3 performance adjusted MW (944.4 effective MW).
- **Demand.** Prior to January 9, 2017, the hourly regulation demand was set to 525.0 effective MW for nonramp hours and 700.0 effective MW for ramp hours. Starting January 9, 2017, the hourly regulation demand was set to 525.0 effective MW for nonramp hours and 800.0 effective MW for ramp hours.
- **Supply and Demand.** The nonramp regulation requirement of 525.0 effective MW was provided by a combination of RegA and RegD resources equal to 497.0 hourly average MW in the first six months of 2017. This is a decrease of 27.5 MW from the first six months of 2016, when the average hourly total regulation cleared MW for nonramp hours were 524.6 MW. The ramp regulation requirement of 700.0 effective MW prior to January 9, 2017, and 800.0 effective MW after January 9, 2017, was provided by a combination of RegA and RegD resources equal to 714.3 hourly average MW in the first six months of 2017. This is a decrease of 72.1 MW from the first six months of 2016, where the average hourly regulation cleared MW for ramp hours were 642.2 MW.

  The ratio of the average hourly eligible supply of regulation to average hourly regulation demand for ramp hours was 1.99 in the first six months of 2017. This is an increase of 7.2 percent from the first six months of 2016, when the ratio was 1.86. The ratio of the average hourly eligible supply of regulation to average hourly regulation demand required for nonramp hours was 2.30 in the first six months of 2017. This is an increase of 1.2 percent from the first six months of 2016, when the ratio was 2.27.
- **Market Concentration.** In the first six months of 2017, the three pivotal supplier test was failed in 91.2 percent of hours. In the first six months of 2017, the weighted average HHI of RegA resources was 2722, which is highly concentrated and the weighted average HHI of RegD resources was 1629, which is highly concentrated.

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.[139] In the first six months of 2017, there were 197 resources following the RegA signal and 52 resources following the RegD signal.

Market Performance

- **Price and Cost.** The weighted average clearing price for regulation was $15.08 per effective MW of regulation in the first six months of 2017, a decrease of $0.82 per MW, or 5.1 percent, from of the first six months of 2016. The cost of regulation in the first six months of 2017 was $20.64 per effective MW of regulation, an increase of $2.34 per MW, or 12.8 percent, from the first six months of 2016. The decrease in regulation price in the first six months of 2017 resulted primarily from reductions in the opportunity cost component of the regulation clearing prices due to low energy prices in the first six months of 2017 compared to the first six months of 2016.

138 On peak and off peak hours are now designated as ramp and nonramp hours. The definitions change by season. See "Regulation requirement definition," <http://www.pjm.com/~/media/markets-ops/ancillary/regulation-requirement-definition.ashx>.

139 See the *2016 State of the Market Report for PJM*, Volume II, Appendix F "Ancillary Services Markets."

- **Prices.** 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 and settlement processes. If the Regulation Market were functioning efficiently, RegD and RegA resources would be paid the same price per effective MW. RegA resources are paid on the basis of dollars per effective MW of RegA. RegD resources are not paid in terms of dollars per effective MW of RegA because the marginal benefit factor is not used in settlements. When the marginal benefit factor is above 1.0, RegD resources are generally (depending on the mileage ratio) underpaid on a per effective MW basis. When the MBF is less than one, RegD resources are generally overpaid on a per effective MW basis. Currently, the average MBF is less than 1.0, resulting in persistent overpayment of RegD resources that creates an artificial incentive for inefficient entry of RegD resources. The MBF averaged less than 1.0 in five of the first six months of 2017, resulting in RegD resources being paid an average of $9.67 million (568.8 percent) more than they should have in the first six months of 2017. In each of the first six months of 2016, the average MBF was less than 1.0, resulting in RegD resources being paid an average of $8.07 million (873.4 percent) more than they should have been.
- **Marginal Benefit Factor Function.** The marginal benefit factor (MBF) is intended to measure the operational substitutability of RegD resources for RegA resources. The marginal benefit factor function is incorrectly defined and applied in the PJM market clearing. Correctly defined, the MBF function represents the Marginal Rate of Technical Substitution (MRTS) between RegA and RegD. Correctly implemented, the MBF would be consistently applied in the Regulation Market clearing and settlement. The current incorrect and inconsistent implementation of the MBF function has resulted in the PJM Regulation Market over procuring RegD relative to RegA in most hours and in a consistently inefficient market signal to participants regarding the value of RegD to the market in every hour. This over procurement began to degrade the ability of PJM to control ACE in some hours while at the same time increasing the cost of regulation.[140]
- **Changes to the Regulation Market.** On December 14, 2015, PJM changed the MBF curve in an attempt to reduce the over procurement of RegD. The modification to the marginal benefit curve did not correct the identified issues. PJM made additional changes which went into effect on January 9, 2017. These include changing the definition of nonramp and ramp hours based on the season, increasing the effective MW requirement during ramp hours from 700 MW to 800 MW, adjusting the currently independent RegA and RegD signals to be interdependent, and changing the 15-minute neutrality requirement of the RegD signal to a 30-minute conditional neutrality requirement. As a result of the changes implemented on January 9, 2017, the average daily payment per performance adjusted RegD MW increased by 45.8 percent, from $17.42 between the January 1, 2016, through January 8, 2017, period (prior to the change in signal design), to $25.40 between the January 9, 2017, through June 30, 2017, period (after the change in signal design).

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).[141]

In the first six months of 2017, total black start charges were $34.0 million, including $33.8 million in revenue requirement charges and $0.138 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

140 The issues associated with over procurement were brought before the PJM Operating Committee in May of 2015. "Regulation Performance Impacts," PJM Operating Committee, (May 26, 2015), which can be accessed at: <http://www.pjm.com/committees-and-groups/committees/oc.aspx>.
141 OATT Schedule 1 § 1.3BB.

the ALR option or for black start testing. Black start zonal charges for the first six months of 2017 ranged from $0.05 per MW-day in the DLCO Zone (total charges were $25,105) to $4.28 per MW-day in the PENELEC Zone (total charges were $2,253,666).

Reactive

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

Reactive capability revenue requirements are based on FERC approved filings.[142] Reactive service charges are paid to units that operate in real time outside of their normal range at the direction of PJM for the purpose of providing reactive service. Reactive service charges are paid for scheduling in the Day-Ahead Energy Market and committing units in real time that provide reactive service. In the first six months of 2017, total reactive charges were $168.9 million, a 15.1 percent increase from $146.8 million in 2016. Reactive capability revenue requirement charges increased from $146.1 million in 2016 to $159.6 million and reactive service charges increased from $0.6 million to $9.3 million in 2017. Total charges in 2017 ranged from $1,239 in the RECO Zone to $19.3 million in the AEP Zone.

Section 10 Recommendations

- The MMU recommends that the Regulation Market be modified to incorporate a consistent application of the marginal benefit factor (MBF) throughout the optimization, assignment and settlement process. The MBF should be defined as the Marginal Rate of Technical Substitution (MRTS) between RegA and RegD. (Priority: High. First reported 2012. Status: Not adopted.)
- The MMU recommends that all data necessary to perform the Regulation Market three pivotal supplier test be saved so that the test can be replicated. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that there be a penalty enforced in the Regulation Market as a reduction in performance score and/or a forfeiture of revenues when resource owners elect to deassign assigned regulation resources within the hour, to prevent gaming. (Priority: Medium. First reported 2016. Status: Not adopted.)
- 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: Not adopted.)
- The MMU recommends a market design changes to improve the performance of the Regulation Market, including use of a single five minute clearing price based on actual LMP and actual LOC, modifications to the LOC calculation, a software change to save some data elements necessary for verifying market outcomes, and further documentation of the implementation of the market design. (Priority: Medium. First reported 2010. Status: Partially adopted in 2012.)
- The MMU recommends that the rule requiring that tier 1 synchronized reserve resources are paid the tier 2 price when the nonsynchronized reserve price is above zero be eliminated immediately and that, under the current rule, tier 1 synchronized reserve resources not be paid the tier 2 price when they do not respond. (Priority: High. First reported 2013. Status: Not adopted.)
- 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 unit owners to select a reason in Markets Gateway whenever making a unit unavailable either daily or hourly or setting the offer MW to 0 MW. (Priority: Medium. First reported 2013. Status: Partially adopted.)
- The MMU recommends that PJM be more explicit and transparent about why tier 1 biasing is used in defining demand in the Tier 2 Synchronized Reserve Market. The MMU recommends that PJM define rules for estimating tier 1 MW, define rules for the use and amount of tier 1 biasing

142 OATT Schedule 2.

and identify the rule based reasons for each instance of biasing. (Priority: Medium. First reported 2012. Status: Not adopted.)

- The MMU recommends that the single clearing price for synchronized reserves be determined based on the actual five minute LMP and actual LOC and not the forecast LMP. (Priority: Low. First reported 2010. Status: Adopted.)
- 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 2014. Status: Adopted 2014.)
- The MMU recommends that PJM modify the DASR Market to ensure that all resources cleared incur a real-time performance obligation. (Priority: Low. First reported 2013. Status: Not adopted.)
- 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 2015. Status: Not adopted.)
- The MMU recommends that separate payments for reactive capability be eliminated and the cost of reactive capability be recovered in the capacity market. (Priority: Medium. First reported 2016. 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.)

Section 10 Conclusion

The current PJM regulation market design that incorporates two signals using two resource types was a result of Commission Order 755 and subsequent orders that required a flawed design.[143]

143 *Frequency Regulation Compensation in the Organized Wholesale Power Markets*, Order No. 755, 137 FERC ¶ 61,064 at PP 197–200 (2011)

The current design of the PJM Regulation Market is significantly flawed. The market design has failed to correctly incorporate the marginal rate of technical substitution (MRTS) in market clearing and settlement. The market design uses the marginal benefit factor (MBF) to incorrectly represent the MRTS and uses a mileage ratio instead of the MBF in settlement. This failure to correctly and consistently incorporate the MRTS into the regulation market design has resulted in both underpayment and overpayment of RegD resources and in the over procurement of RegD resources in all hours. The market results continue to include the incorrect definition of opportunity cost. These issues have led to the MMU's conclusion that the regulation market design is flawed.

To address these flaws, the MMU and PJM developed a joint proposal which was approved by the PJM Members Committee on July 27, 2017. The PJM/MMU joint proposal addresses issues with the inconsistent application of the marginal benefit factor throughout the optimization and settlement process in the PJM Regulation Market.

The structure of the 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 product 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 remains less than 100 percent. For the six spinning events 10 minutes or longer in 2016, the average tier 2 synchronized reserve response was 85.5 percent of all scheduled MW. For the four spinning events of 10 minutes or longer in the first six months of 2017, the response was 87.3 percent of scheduled tier 2 MW.

The rule that requires payment of the tier 2 synchronized reserve price to tier 1 synchronized reserve resources when the nonsynchronized reserve price is greater than zero, is inefficient and results in a substantial windfall payment to the holders of tier 1 synchronized reserve resources. Tier 1 resources have no obligation to perform and pay no penalties if they do not perform, and tier 1 resources do not incur any costs when they are part of the tier 1 estimate in the market solution. Tier 1 resources are already paid for their response if they do respond. Tier 1 resources require no additional payment. If tier 1 resources wish to be paid as tier 2 resources, the rules provide the opportunity to make competitive offers in the tier 2 market and take on the associated obligations. Overpayment of tier 1 resources based on this rule added $89.7 million to the cost of primary reserve in 2014, $34.1 million in 2015, $4.9 million in 2016, and $0.8 million in the first six months of 2017.

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, although the market design is flawed. The MMU concludes that the synchronized reserve market results were competitive. The MMU concludes that the DASR market results were competitive, although offers above the competitive level continue to affect prices.

Overview: Section 11, "Congestion and Marginal Losses"

Congestion Cost

- **Total Congestion.** Total congestion costs decreased by $193.6 million or 40.4 percent, from $479.1 million in the first six months of 2016 to $285.5 million in the first six months of 2017.
- **Day-Ahead Congestion.** Day-ahead congestion costs decreased by $271.1 million or 42.2 percent, from $514.0 million in the first six months of 2016 to $296.8 million in the first six months of 2017.
- **Balancing Congestion.** Balancing congestion costs increased by $23.6 million or 67.6 percent, from -$34.8 million in the first six months of 2016 to -$11.3 million in the first six months of 2017.
- **Real-Time Congestion.** Real-time congestion costs decreased by $215.8 million or 42.9 percent, from $502.6 million in the first six months of 2016 to $286.8 million in the first six months of 2017.
- **Monthly Congestion.** Monthly total congestion costs in the first six months of 2017 ranged from $30.5 million in April to $64.4 million in June.
- **Geographic Differences in CLMP.** Differences in CLMP among eastern, southern and western control zones in PJM were primarily a result of congestion on the Westwood Flowgate, the Emilie – Falls Line, the Cherry Valley Transformer, the AP South Interface and the Alpine – Belvidere Flowgate.
- **Congestion Frequency.** Congestion frequency continued to be significantly higher in the Day-Ahead Energy Market than in the Real-Time Energy Market in the first six months of 2017. The number of congestion event hours in the Day-Ahead Energy Market was about 13 times the number of congestion event hours in the Real-Time Energy Market.

  Day-ahead congestion event hours decreased significantly after September 8, 2014. The decrease 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. However, day-ahead congestion frequency increased by 17.8 percent from 129,926 congestion event hours in the first six months of 2016 to 153,096 congestion event hours in the first six months of 2017. The increase was a result of the increase in UTC transactions that followed the expiration of the fifteen month resettlement period for the proceeding related to uplift charges for UTC transactions.[144]

  Real-time congestion frequency decreased by 12.4 percent from 13,099 congestion event hours in the first six months of 2016 to 11,470 congestion event hours in the first six months of 2017.

144 *See* FERC Docket No. EL14-37.

- **Congested Facilities.** Day-ahead, congestion-event hours increased on all types of facilities except interfaces. Real-time, congestion-event hours increased on all types of facilities except lines.

  The Westwood Flowgate was the largest contributor to congestion costs in the first six months of 2017. With $16.4 million in total congestion costs, it accounted for 5.8 percent of the total PJM congestion costs in the first six months of 2017.

- **Zonal Congestion.** ComEd had the largest total congestion costs among all control zones in the first six months of 2017. ComEd had $92.2 million in total congestion costs, comprised of -$70.0 million in total load congestion payments, -$161.8 million in total generation congestion credits and $0.4 million in explicit congestion costs. The Alpine – Belvidere Transformer, the Cherry Valley Transformer, the Braidwood – East Frankfort Line, the Westwood Flowgate and the Byron – Cherry Valley Flowgate contributed $39.7 million, or 43.1 percent of the total ComEd control zone congestion costs.

- **Ownership.** In the first six months of 2017, financial entities were net receivers and physical entities were net payers of congestion charges. In the first six months of 2017, financial entities were paid $2.0 million in congestion credits compared to $17.3 million received in congestion credits in the first six months of 2016. In the first six months of 2017, physical entities paid $287.5 million in congestion charges, a decrease of $208.8 million or 42.1 percent compared to the first six months of 2016.

Marginal Loss Cost

- **Total Marginal Loss Costs.** Total marginal loss costs increased by $14.8 million or 4.8 percent, from $305.8 million in the first six months of 2016 to $320.6 million in the first six months of 2017. The loss MWh in PJM decreased by 84.2 GWh or 1.2 percent, from 7,223.4 GWh in the first six months of 2016 to 7,139.2 GWh in the first six months of 2017. The loss component of real-time LMP in the first six months of 2017 remained $0.014, the same as it was in the first six months of 2016.

- **Monthly Total Marginal Loss Costs.** Monthly total marginal loss costs in the first six months of 2017 ranged from $44.2 million in April to $62.8 million in March.

- **Day-Ahead Marginal Loss Costs.** Day-ahead marginal loss costs increased by $29.3 million or 8.7 percent, from $335.4 million in the first six months of 2016 to $364.7 million in the first six months of 2017.

- **Balancing Marginal Loss Costs.** Balancing marginal loss costs decreased by $14.5 million or 49.0 percent, from -$29.5 million in the first six months of 2016 to -$44.0 million in the first six months of 2017.

- **Total Marginal Loss Surplus.** The total marginal loss surplus decreased in the first six months of 2017 by $2.3 million or 2.3 percent, from $100.5 million in the first six months of 2016, to $98.2 million in the first six months of 2017.

Energy Cost

- **Total Energy Costs.** Total energy costs decreased by $18.0 million or 8.1 percent, from -$204.2 million in the first six months of 2016 to -$222.2 million in the first six months of 2017.

- **Day-Ahead Energy Costs.** Day-ahead energy costs decreased by $40.2 million or 14.3 percent, from -$282.3 million in the first six months of 2016 to -$322.5 million in the first six months of 2017.

- **Balancing Energy Costs.** Balancing energy costs increased by $21.8 million or 28.0 percent, from $77.7 million in the first six months of 2016 to $99.4 million in the first six months of 2017.

- **Monthly Total Energy Costs.** Monthly total energy costs in the first six months of 2017 ranged from -$48.2 million in January to -$31.0 million in April.

Section 11 Conclusion

Congestion is defined to be 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 and 86.5 percent of total congestion costs including congestion in the Day-Ahead Energy Market and the balancing energy market for the 14/15 and 15/16 planning periods. For the 16/17 planning period ARRs and self scheduled FTRs offset 98.1 percent of total congestion costs.

Overview: Section 12, "Planning"

Planned Generation and Retirements

- **Planned Generation.** As of June 30, 2017, 94,755.8 MW of capacity were in generation request queues for construction through 2024, compared to an average installed capacity of 199,987.9 MW as of June 30, 2017. Of the capacity in queues, 9,204.2 MW, or 9.7 percent, are uprates and the rest are new generation. Wind projects account for 15,419.6 MW of nameplate capacity or 16.3 percent of the capacity in the queues. Natural gas fired projects account for 59,981.5 MW of capacity or 63.3 percent of the capacity in the queues.
- Generation Retirements. As shown in Table 1-2-5, 32,620.7 MW have been, or are planned to be, retired between 2011 and 2020. Of that, 7,475.1 MW are planned to retire after the first six months of 2017. In the first six months of 2017, 1,495 MW were retired. Of the 7,475.1 MW pending retirement, 5,212.0 MW are coal units. The coal unit retirements were a result of low gas prices, low capacity prices and the investments required for compliance with the EPA's Mercury and Air Toxics Standards (MATS) for some units.
- **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 coal fired steam units retire. There are 279.0 MW of coal fired steam capacity and 59,981.5 MW of gas fired capacity in the queue. The replacement of coal fired steam units by units burning natural gas will significantly affect future congestion, the role of firm and interruptible gas supply, and natural gas supply infrastructure.

Generation and Transmission Interconnection Planning Process

- Any entity that requests interconnection of a new generating facility, including increases to the capacity of an existing generating unit, or that requests interconnection of a merchant transmission facility, must follow the process defined in the PJM tariff to obtain interconnection service.[145] PJM's process is designed to ensure that new generation is added in a reliable and systematic manner. 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. The queue process results in a substantial number of projects that drop out. Excluding currently active projects and projects currently under construction, 3,538 projects, representing 461,602.7 MW, have entered the queue process since its inception. Of those, 727 projects, representing 49,472.4 MW, went into service. Of the projects that entered the queue process, 68.8 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

145 See OATT Parts IV & VI.

delays associated with the submittal of large numbers of requests at the end of the queue window, which resulted in revisions to the PJM Open Access Transmission Tariff, effective October 31, 2016.[146] [147] On December 15, 2016, the Commission issued a notice of proposed rulemaking proposing additional queue reforms intended to improve certainty, promote more informed interconnection, and enhance interconnection processes.[148]

- 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."[149] 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.[150] [151] On August 5, 2016, PJM announced that the Artificial Island project was to be suspended immediately due to unanticipated project complexities and significant cost overruns. On March 3, 2017, PJM held a special Transmission Expansion Advisory Committee (TEAC) meeting to discuss their updated analysis of the Artificial Island project. PJM staff presented updated assumptions that went into the new project analysis. In consultation with project developers and stakeholders, PJM made several major revisions to the project. These included switching the interconnection point from the Salem Substation to the Hope Creek Substation, removal of the New Freedom switched vertical circuit (SVC) from the project scope, and removal of the optical ground wire (OPGW) from the project scope. These revisions led to a revised total project cost estimate of $280 million, $240 million less than the previous $420 million project cost estimate released in February 2016. On April 6, 2017, the PJM Board lifted a suspension of the project. It is expected to be in service by June 2020.

- 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. The allocation process has been upheld by the FERC despite repeated challenges.[152]

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 are currently

146 See Earlier Queue Submittal Task Force at <http://www.pjm.com/committees-and-groups/closed-groups/eqstf.aspx>
147 See Letter Order, ER16-2518-000 (Oct. 7, 2016).
148 157 FERC ¶ 61,212 (2016).
149 See OATT § 1 (Transmission Owner).
150 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>.
151 See letter from Terry Boston concerning the Artificial Island Project at <http://www.pjm.com/-/media/library/reports-notices/special-reports/board-statement-on-artificial-island-project.ashx?la=en>.

152 See 155 FERC ¶ 61,090 (2016); 155 FERC ¶ 61,089 (2016); 155 FERC ¶ 61,088 (2016); see also Order No. 1000, FERC Stats. & Regs. ¶ 31,323 (2011), *order on reh'g*, Order No. 1000-A, 139 FERC ¶ 61,132, *order on reh'g and clarification*, Order No. 1000-B, 141 FERC ¶ 61,044 (2012), *aff'd sub nom.* 762 F.3d 41, 412 (D.C. Cir. 2014); 142 FERC ¶ 61,074 (2013) (accepting the proposed PJM cost allocation method, effective February 1, 2013, subject to the outcome of PJM's Order No. 1000 regional compliance filing proceeding); 142 FERC ¶ 61,214 (2013), *order on reh'g and compliance*, 147 FERC ¶ 61,128 (2014), *order on reh'g and compliance*, 150 FERC ¶ 61,038 (2015), order on reh'g and compliance, 151 FERC ¶ 61,250 (2015).

three backbone projects under development, Surry Skiffes Creek 500kV, the Northern New Jersey 345 kV Upgrades, and Byron Wayne 345 kV.[153]

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 or late and whether or not they will allow the outage.[154]
- There were 8,988 transmission outage requests submitted in the first six months of 2017. Of the requested outages, 76.3 percent were planned for five days or shorter and 7.9 percent were planned for longer than 30 days. Of the requested outages, 48.9 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. First reported 2015. 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.[155] (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 tra nsmission owners are vertically integrated and the owner of transmission also owns generation. (Priority: Low. First reported 2013. Status: Not adopted.)
- 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

153 See "2016 RTEP Process Scope and Input Assumptions White Paper," P 23. <http://www.pjm.com/~/media/documents/reports/2016-rtep-process-scope-and-input-assumptions.ashx> Accessed July 17, 2017.
154 PJM. "Manual 03: Transmission Operations," Revision 51 (June 1, 2017), Section 4.
155 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>.

be addressed. The goal should be to remove barriers to competition from merchant transmission. (Priority: Medium. First reported 2015. Status: Not adopted.)

- The MMU recommends consideration of changing the minimum distribution factor in the allocation from 0.01 to 0.00 and adding a threshold minimum usage impact on the line. (Priority: Medium. First reported 2015. 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. First reported 2015. 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 2014. Status: Partially 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, "FTRs and ARRs"

Auction Revenue Rights

Market Structure

- **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. Residual ARRs with negative target allocations are not allocated to participants. Instead they are removed and the model is rerun until a minimum of negative target allocation residual ARRs are found.

  In the 2016/2017 planning period, PJM allocated a total of 35,034.9 MW of residual ARRs, up from 30,118.1 MW in the 2015/2016 planning period, with a total target allocation of $7.0 million for the 2016/2017 planning period, down from $7.7 million for the 2015/2016 planning period.

- **ARR Reassignment for Retail Load Switching.** There were 455,638 MW of ARRs associated with $659,000 of revenue that were reassigned in 2015/2016 planning period. There were 44,056 MW of ARRs associated with $492,500 of revenue that were reassigned for the 2016/2017 planning period.

Market Performance

- **Revenue Adequacy.** For the 2016/2017 planning period, the ARR target allocations, which are based on the nodal price differences from the Annual FTR Auction, were $914.2 million, while PJM collected $941.5 million from the combined Long Term, Annual and Monthly Balance of Planning Period FTR Auctions, making ARRs revenue adequate. For the 2015/2016 planning period, the ARR target allocations were $931.6 million while PJM collected $968.1 million from the combined Long Term, Annual and Monthly Balance of Planning Period FTR Auctions. The year over year decrease in ARR target allocations and auction revenue is a result of decreased prices from the previous planning period resulting from continued reduced allocation of Stage 1B and Stage 2 ARRs. ARR revenue adequacy is also affected by PJM's clearing of additional counter flow FTRs to alleviate infeasibilities from Stage 1A.
- **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, which include congestion in the Day-Ahead Energy Market and the balancing energy market, for the 2014/2015 planning period. In the 2016/2017 planning

period, total ARR and self scheduled FTR revenues offset 98.1 percent of total congestion costs. The total offset for the last six planning periods is 73.3 percent. The goal of the design should be to return 100 percent of the congestion revenues to the load.

Financial Transmission Rights

Market Structure

- **Supply.** The principal binding constraints limiting the supply of FTRs in the 2017/2020 Long Term FTR Auction include the St. John's Transformer in Dominion and the Elliott-Rosewood Line in AEP. The principal binding constraints limiting the supply of FTRs in the Annual FTR Auction for the 2017/2018 planning period include the Bunsonville Flowgate in MISO and the Silver Lake-Silver Lake Line in ComEd.
- **Market participants can sell FTRs.** In the 2017/2020 Long Term FTR Auction, total participant FTR sell offers were 208,405 MW, down from 327,980 in the 2016/2017 Long Term FTR Auction. In the 2017/2018 Annual FTR Auction, total participant sell offers were 276,844 MW, down from 378,431 MW in the 2016/2017 Annual FTR Auction. In the Monthly Balance of Planning Period FTR Auctions for the 2016/2017 planning period, total participant FTR sell offers were 4,342,320 MW, down from 4,891,443 MW for the same period during the 2015/2016 planning period.
- **Demand.** In the 2017/2020 Long Term FTR Auction, total FTR buy bids were 2,176,871 MW, down 11.5 percent from 2,459,946 MW the previous planning period. There were 2,306,063 MW of buy and self scheduled bids in the 2017/2018 Annual FTR Auction, down 11.0 percent from 2,592,183 MW the previous planning period. The total FTR buy bids from the Monthly Balance of Planning Period FTR Auctions for the 2016/2017 planning period decreased 21.6 percent from 25,686,865 MW for the same time period of the prior planning period, to 20,144,884 MW.
- **Patterns of Ownership.** For the 2017/2020 Long Term FTR Auction, financial entities purchased 77.5 percent of prevailing flow FTRs and 84.9 percent of counter flow FTRs. For the 2017/2018 Annual FTR Auction, financial participants purchased 60.1 percent of all prevailing flow FTRs and 76.7 percent of all counter flow FTRs. For the Monthly Balance of Planning Period Auctions, financial entities purchased 74.9 percent of prevailing flow and 82.6 percent of counter flow FTRs January through June of 2017. Financial entities owned 64.8 percent of all prevailing and counter flow FTRs, including 55.4 percent of all prevailing flow FTRs and 77.5 percent of all counter flow FTRs during the period from January through June 2017.

Market Behavior

- **FTR Forfeitures.** FTR forfeitures were not billed after January 19, 2017, pending retroactive implementation of a new FTR forfeiture rule.
- **Credit Issues.** There were no defaults in the first six months of 2017.

Market Performance

- **Volume.** The 2017/2020 Long Term FTR Auction cleared 297,083 MW (13.6 percent) of demand of FTR buy bids, up 7.1 percent from 277,397 MW (11.3 percent) in the 2016/2019 Long Term FTR Auction. The Long Term FTR Auction also cleared 36,782 MW (17.6 percent) of FTR sell offers, compared to 61,210 (18.7 percent), a 40.0 percent decrease.
- In the Annual FTR Auction for the 2017/2018 planning period 513,263 MW (22.3 percent) of buy and self-schedule bids cleared, up 22.1 percent from 420,198 MW (16.2 percent) for the previous planning period. In the 2016/2017 planning period Monthly Balance of Planning Period FTR Auctions cleared 2,311,996 MW (11.5 percent) of FTR buy bids and 1,004,662 MW (23.1 percent) of FTR sell offers cleared.
- **Price.** The weighted-average buy-bid FTR price in the 2017/2020 Long Term FTR Auction was $0.04 per MW, down from $0.05 per MW for the 2016/2019 planning period. The weighted-average buy-bid FTR price in the Annual FTR Auction for the 2017/2018 planning period was $0.51 per MW, up from $0.49 per MW in the 2016/2017 planning period. The weighted average buy bid cleared FTR price in the Monthly Balance of Planning Period FTR Auctions for 2016/2017 planning period was $0.12, unchanged from $0.21 per MW for the same period in the 2015/2016 planning period.

- **Revenue.** The 2017/2020 Long Term FTR Auction generated $26.7 million of net revenue for all FTRs, up from $23.2 million for the 2016/2019 Long Term FTR Auction. The 2017/2018 Annual FTR Auction generated $542.2 million in net revenue, down from $909.0 million for the 2016/2017 Annual FTR Auction. The Monthly Balance of Planning Period FTR Auctions generated $32.5 million in net revenue for all FTRs for the 2016/2017 planning period, up from $31.8 million for the same time period in the 2015/2016 planning period.
- **Revenue Adequacy.** FTRs were paid at 100 percent of the target allocation level for the 2016/2017 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 decision to include more outages and PJM's decision to include additional constraints (closed loop interfaces) in the model, 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.
- **Profitability.** FTR profitability is the difference between the revenue received for an FTR and the cost of the FTR. In the 2016/2017 planning period, physical entities made $39.7 million in profits, largely due to self scheduled FTRs, and financial entities lost $13.5 million. Revenues from self scheduled FTRs are more accurately described as a return of congestion rather than profits.

Section 13 Recommendations

- The MMU recommends that the ARR/FTR design be modified to ensure that the rights to all congestion revenues are assigned to load. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that all FTR auction revenue be distributed to ARR holders. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that FTR auction revenues not be used to buy counter flow FTRs for the purpose of improving FTR payout ratios.[156] (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that all historical generation to load paths be eliminated as a basis for allocating ARRs. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that counter flow FTRs be eliminated. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM eliminate portfolio netting to eliminate cross subsidies among FTR market participants. (Priority: High. First reported 2012. Status: Not adopted.)
- 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 implement a seasonal ARR and FTR allocation system to better represent outages. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM 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: Adopted.)
- 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.)
- The MMU recommends that PJM improve transmission outage modeling in the FTR auction models. (Priority: Low. First reported 2013. Status: Not adopted, 2014/2015 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, 2014/2015 planning period.)

156 See "PJM Manual 6: Financial Transmission Rights," Rev. 17 (June 1, 2016) at 55.

- 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: Adopted 2016.)
- The MMU recommends that Long Term FTRs be modified to include only a one year ahead FTR. (Priority: High. New recommendation. Status: Not adopted.)

Section 13 Conclusion

The annual ARR allocation should be designed to ensure that the rights to all congestion revenues are assigned to firm transmission service customers, without requiring contract path physical transmission rights that are 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 the benefits of firm low cost generation delivered using the transmission system in the form of revenues which offset congestion. Financial transmission rights and the associated revenues were directly provided to loads in recognition of the fact that loads pay for the transmission system which permits low cost generation to be delivered to load and loads pay congestion. 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 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 the rights to all the congestion revenues and 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 2014/2015 planning period. For the 2015/2016 planning period, ARRs and self scheduled FTRs offset 86.5 percent of total congestion costs. For the 2016/2017 planning period, ARRs and self scheduled FTRs offset 98.1 percent of total congestion costs.

Load should never be required to subsidize payments to FTR holders, regardless of the reason. Such subsidies have been suggested repeatedly.[157] 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.

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

The Commission's order will shift substantial revenue from load to the holders of FTRs and reduce the ability of load to offset congestion. If these rules had been in place for the 2016/2017 planning period, and ARR/FTR allocations had remained constant, ARR holders would have gone from an offset of 98.1 percent under the current rule, to 89.5 percent under the new rule, a loss of $81.4 million. FTR holders would have received a corresponding windfall and revenues to FTR holder would have exceeded target allocations by $179.0 million.

If these rules had been in place beginning with the 2011/2012 planning period, ARR holders would have received $1,034.2 million less in congestion offsets from the 2011/2012 through the 2016/2017 planning period. The total overpayment to FTR holders for the 2011/2012 through 2016/2017 planning period would have been $944.4 million. The underpayment to load and the overpayment to FTR holders is a result of several factors in the new rules all of which mean the transfer of revenues to FTR holders and the shifting of costs to load. Load is now required to pay for balancing congestion, which significantly increases costs to load and significantly increases revenues paid to FTR holders. PJM will continue to clear counter flow FTRs using excess auction revenues in order to make it possible to sell more prevailing flow FTRs. FTR holders will receive excess day-ahead congestion revenues in excess of target allocations. FTR holders will receive excess auction revenue, which is what FTR holders were willing to pay for FTRs in excess of what is provided to ARR 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 balancing 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.

PJM used a more conservative approach to modeling the transmission capability for the 2014/2015 through 2016/2017 planning periods compared to the 2013/2014 planning period. PJM simply used higher outage levels and 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. For the 2017/2018 planning period PJM assigned all balancing congestion and M2M payments to load and exports. As a result, PJM also reversed course and increased the availability of Stage 1B and Stage 2 FTRs. The market response to the increased supply of FTRs was lower bid prices and clearing prices.

Clearing prices fell and cleared quantities increased from the 2010/2011 planning period through the 2013/2014 planning period. The market response to lower revenue adequacy was to reduce bid prices and to increase bid volumes and offer volumes. In the 2014/2015, 2015/2016 and 2016/2017 planning periods, due to reduced ARR allocations, FTR volume decreased relative to the 2013/2014 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 2013/2014 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 2013/2014 planning period from the reported 72.8 percent to 91.0 percent. For the 2014/2015, 2015/2016 and 2016/2017 planning periods 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 are 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. There is a reason that transmission is not built to address the Stage 1A overallocation issue. PJM's transmission planning process (RTEP) does not identify a need for new transmission because there is, in fact, no need for new transmission associated with Stage 1A ARRs. The Stage 1A overallocation issue is a fiction based on the use of outdated and irrelevant generation to load paths to assign Stage 1A rights that have nothing to do with actual power flows.

The result of removing portfolio netting, applying a payout ratio to counter flow FTRs and eliminating Stage 1A ARR overallocation in the 2013/2014 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 different line ratings, 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; the payment of congestion revenues to UTCs; 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.

It is not clear, in a competitive market, why FTR purchases by financial entities remain persistently profitable. In a competitive market, it would be expected that profits would be competed away. It is also not clear, in a competitive market, why the ownership structure of long term FTRs is so highly concentrated. The apparent lack of competition to purchase Long Term FTRs (three year product) results in low prices when compared to the resale prices in Annual FTR Auctions. In a competitive market the price of Long Term FTRs (three year product) would be expected to converge with the prices of Annual FTRs, but there has been a persistent, wide divergence that has made the purchase of Long Term FTRs very profitable.

For the 2014/2015, 2015/2016 and 2016/2017 planning periods FTRs have been revenue adequate. This is not because the underlying market design 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.

Load is significantly worse off as a result of the changes made to the FTR/ARR process by PJM based on the FERC order of September 15, 2016. ARR revenues were significantly reduced for the 2017/2018 FTR Auction, the first auction under the new rules. In addition, the certainty of the ARR offset to congestion, whatever the level, was eliminated by the assignment of 100 percent of balancing congestion to load. ARR holders will be worse off as a result of paying balancing congestion but will not know exactly how much worse off until the end of the planning year.

In addition, it has become increasingly clear that the three year FTR product sold in the Long Term FTR Auction should be eliminated. Ownership of the product is extremely highly concentrated. The buyers of the product resell the annual segments of the product for multiples of the purchase price. There is no reason for the very small number of purchasers to continue to be subsidized.