Energy Market

The PJM Energy Market comprises all types of energy transactions, including the sale or purchase of energy in PJM's Day-Ahead and Real-Time Energy Markets, bilateral and forward markets and self-supply. Energy transactions analyzed in this report include those in the PJM Day-Ahead and Real-Time Energy Markets. These markets provide key benchmarks against which market participants may measure results of transactions in other markets.

The Market Monitoring Unit (MMU) analyzed measures of market structure, participant conduct and market performance in the first three months of 2017, including market size, concentration, residual supply index, and price.[1] The MMU concludes that the PJM energy market results were competitive in the first three months of 2017.

Table 3-1 The energy market results were competitive

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

- The aggregate market structure was evaluated as competitive. The hourly HHI (Herfindahl-Hirschman Index) results indicate that by the FERC standards, the PJM Energy Market in the first three months of 2017 was unconcentrated. Average HHI was 980 with a minimum of 882and a maximum of 1126in the first three 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. 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 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

1 Analysis of 2017 market results requires comparison to prior years. In 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, PJM integrated the American Transmission Systems, Inc. (ATSI) Control Zone. In January 2012, PJM integrated the Duke Energy Ohio/Kentucky (DEOK) Control Zone. In June 2013, PJM integrated the Eastern Kentucky Power Cooperative (EKPC). 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 control zones, the integrations, their timing and their impact on the footprint of the PJM service territory, see the *2015 State of the Market Report for PJM*, Appendix A, "PJM Geography."

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.[2] 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.[3] 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 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.

2 OATT Attachment M (PJM Market Monitoring Plan).

3 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.

Overview

Market Structure

- **Supply.** Supply includes physical generation and imports and virtual transactions. The maximum of average offered real-time generation decreased by 2,613 MW, or 1.5 percent, from 173,439 MW in the first three months of 2016 to 170,827 MW in the first three months of 2017. In the first three months 2017, 1,317.7 MW of new capacity resources were added. In the first three months 2017, 209.0 MW were retired.

  PJM average real-time cleared generation in the first three months of 2017 increased by 2,604 MW, or 2.9 percent, from the first three months of 2016, from 88,470 MW to 91,074 MW.

  PJM average day-ahead cleared supply in the first three months of 2017, including INCs and up to congestion transactions, increased by 5.6 percent from the first three months of 2016, from 133,263 MW to 140,756 MW, primarily as a result of an increase in UTC volumes.

- **Market Concentration.** 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 three months of 2017, coal units provided 33.3 percent, nuclear units 35.8 percent and natural gas units 24.4 percent of total generation. Compared to the first three months of 2016, generation from coal units increased 7.0 percent, generation from natural gas units increased 1.3 percent and generation from nuclear units increased 0.5 percent.

- **Fuel Diversity.** In the first three months of 2017, the fuel diversity of energy generation, measured by the fuel diversity index for energy (FDI_e), increased 0.2 percent over the first three months of 2016.

- **Marginal Resources.** In the PJM Real-Time Energy Market, in the first three months of 2017, coal units were 34.2 percent of marginal resources and natural gas units were 51.0 percent of marginal resources. In the first three months of 2016, coal units were 45.9 percent and natural gas units were 42.0 percent of the marginal resources.

In the PJM Day-Ahead Energy Market, in the first three months of 2017, up to congestion transactions were 83.7 percent of marginal resources, INCs were 4.6 percent of marginal resources, DECs were 7.6 percent of marginal resources, and generation resources were 4.1 percent of marginal resources. In the first three months of 2016, up to congestion transactions were 83.2 percent of marginal resources, INCs were 4.0 percent of marginal resources, DECs were 6.9 percent of marginal resources, and generation resources were 5.9 percent of marginal resources.

- **Demand.** Demand includes physical load and exports and virtual transactions. The PJM accounting peak load during the first three months 2017 was 127,543 MW in the HE 0700 on January 09, 2017, which was 2,333 MW, 1.8 percent, lower than the PJM peak load for the first three months 2016, which was 129,876 MW in the HE 0700 on January 19, 2016.

  PJM average real-time load in the first three months of 2017 decreased from 2016, from 89,322 MW to 87,598 MW. PJM average day-ahead demand in the first three months of 2017, including DECs and up to congestion transactions, increased by 3.9 percent in the first three months of 2016, from 130,534 MW to 135,560 MW.

- **Supply and Demand: Load and Spot Market.** Companies that serve load in PJM can do so using a combination of self-supply, bilateral market purchases and spot market purchases. For the first three months of 2017, 17.9 percent of real-time load was supplied by bilateral contracts, 20.9 percent by spot market purchases and 61.1 percent by self-supply. Compared with the first three months of 2016, reliance on bilateral contracts increased by 5.1 percentage points, reliance on spot market purchases decreased by 3.0 percentage points and reliance on self-supply decreased by 2.1 percentage points.

- **Supply and Demand: Scarcity.** There were no shortage pricing events in the first three 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 three months of 2016 to 0 percent in the first three 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 0.4 percent in the first three months of 2016 to 0.2 percent in the first three months of 2017.

  In the first three months of 2017, nine control zones experienced congestion resulting from one or more constraints binding for 25 or more hours. The analysis of the application of the TPS test to local markets demonstrates that it is working successfully to 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 three months of 2016 to 0.2 percent in the first three months of 2017. In the Real-Time Energy Market, for units committed for reliability reasons, offer-capped unit hours increased from 0.1 percent in the first three months of 2016to 0.2 percent in the first three months of 2017.

- **Markup Index.** The markup index is a summary measure of participant offer behavior for individual marginal units. In the first three months of 2017, in the PJM Real-Time Energy Market, 91.4 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 three months of 2017 was $235.44 while the highest markup in the first three months of 2016 was $219.30.

In the PJM Day-Ahead Energy Market, when using unadjusted cost offers, In the first three months of 2017, 89.3 percent of marginal generating units had offer prices less than $50 per MWh and the average dollar markup was positive, and the 1.1 percent of marginal generating units had offers in the $75 to $100 per MWh range and the average dollar markup was positive.

- **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 three months of 2017, the average hourly increment offers submitted MW increased by 40.3 percent from 7,425 MW in the first three months of 2016 to 10,419 MW in the first three months of 2017, and cleared MW increased by 30.4 percent from 4,691 MW in the first three months of 2016 to 6,115 MW in the first three months of 2017. In the first three months of 2017, the average hourly decrement bids submitted MW increased by 22.5 percent from 7,901 MW in the first three months of 2016 to 9,676 MW in the first three months of 2017, and cleared MW increased by 4.5 percent from 4,661 MW in the first three months of 2016 to 4,869 MW in the first three months of 2017. In the first three months of 2017, the average hourly up to congestion submitted MW increased by 30.1 percent from 145,311 MW in the first three months of 2016 to 188,905 MW in the first three months of 2017, and cleared MW increased by 15.8 percent from 36,711 MW in the first three months of 2016 to 42,516 MW in the first three 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 three months of 2017, 57.1 percent were offered as available for economic dispatch, 3.6 percent were offered as emergency dispatch, 20.3 percent were offered as self scheduled, and 19.0 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 three months of 2017 compared to the first three months of 2016. The load-weighted average real-time LMP was 13.0 percent higher in the first three months of 2017 than in first three months of 2016, $30.28 per MWh versus $26.80 per MWh.

PJM day-ahead energy market prices increased in the first three months of 2017 compared to the first three months of 2016. The load-weighted average day-ahead LMP was 8.8 percent higher in the first three months of 2017 than in the first three months of 2016, $30.40 per MWh versus $27.94 per MWh.

- **Components of LMP.** In the PJM Real-Time Energy Market, in 2016, 40.3 percent of the load-weighted LMP was the result of coal costs, 32.4 percent was the result of gas costs and 2.09 percent was the result of the cost of emission allowances.

  In the PJM Day-Ahead Energy Market in the first three months of 2017, 21.0 percent of the load-weighted LMP was the result of the cost of coal, 24.7 percent was the result of DECs, 21.1 percent was the result of the cost of gas, 19.5 percent was the result of INCs, and 3.4 percent was the result of up to congestion transactions.

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

  In the PJM Real-Time Energy Market in the first three months of 2017, the adjusted markup component of LMP was $3.81 per MWh or 12.6 percent of the PJM real-time, load-weighted average LMP. January had the highest adjusted peak markup component, $5.88 per MWh, or 17.13 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 three months of 2017 was $235.44 per MWh. There were 12 hours in the first three months of 2017 where the positive markup contribution to the PJM system wide, load-weighted, average LMP exceeded $42.99 per MWh.

  In the PJM Day-Ahead Energy Market, INCs, DECs and UTCs have zero markups. In the first three months of 2017, the adjusted markup component of LMP resulting from generation resources was $1.56 per MWh or 5.1 percent of the PJM day-ahead load-weighted average LMP. March had the highest adjusted markup component, $1.99 per MWh or 5.1 percent of the day-ahead load-weighted average LMP.

  Participant behavior was evaluated as competitive because the analysis of markup shows that marginal units generally make offers at, or close to, their marginal costs in both 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 -$1.30 per MWh in the first three months of 2016 and -$0.20 per MWh in the first three 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 three months of 2017.

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.[4] (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.[5] There is currently no PJM documentation in the tariff or manuals explaining how hubs are created and how their definitions are changed.[6] (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that during hours when a generation bus shows a net withdrawal, the energy withdrawal be treated as load, not negative generation, for purposes of calculating load and load-weighted LMP. The MMU recommends that during hours when a load bus shows a net injection, the energy injection be treated as generation, not negative load, for purposes of calculating generation and load-weighted LMP. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM 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

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

5 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.

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

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.)

Conclusion

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

Average PJM real-time cleared generation increased by 2,604 MW, 2.9 percent, and peak load decreased by 2,333 MW, 1.8 percent, in the first three months of 2017 compared to the first three months of 2016. 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. 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 for most hours although aggregate market power does exist during high demand hours. 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.

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 three 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.[7] 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

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

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.

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

The overall energy market results support the conclusion that energy prices in PJM are set, generally, by marginal units operating at, or close to, their marginal costs, although this was not always the case 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 three months of 2017.

Market Structure

Market Concentration

Analysis of supply curve segments of the PJM Energy Market in the first three months of 2017 indicates moderate concentration in the base load and intermediate segments, but high concentration in the peaking segment.[8] High concentration levels, particularly in the peaking segment, increase the probability that a generation owner will be pivotal in the aggregate market during high demand periods. 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. It is possible to have pivotal suppliers in the aggregate market even when the HHI level does not indicate highly concentrated. It is possible to have an exercise of market power even when the HHI level does not indicate highly concentrated.

8 A unit is classified as base load if it runs for more than 50 percent of hours, as intermediate if it runs for less than 50 percent but greater than 10 percent of hours, and as peak if it runs for less than 10 percent of hours.

When transmission constraints exist, local markets are created with ownership that is typically significantly more concentrated than the overall energy market. PJM offer capping rules that limit the exercise of local market power were generally effective in preventing the exercise of market power in the first three months of 2017, although there are issues with the application of market power mitigation for resources whose owners fail the TPS test that permit local market power to be exercised even when mitigation rules are applied. These issues include the lack of a method for consistently determining the cheaper of the cost and price schedules, and the lack of rules requiring that cost based offers equal to short run marginal costs.

The concentration ratio used here is the Herfindahl-Hirschman Index (HHI), calculated by summing the squares of the market shares of all firms in a market. Hourly PJM energy market HHIs were calculated based on the real-time energy output of generators, adjusted for hourly net imports by owner (Table 3-2).

The HHI may not accurately capture market power issues in situations where, for example, there is moderate concentration in all on line resources but there is a high level of concentration in resources needed to meet increases in load. The HHIs for supply curve segments is an indication of such issues with the ownership of incremental resources. An aggregate pivotal supplier test is required to accurately measure the ability of incremental resources to exercise market power when load is high, for example.

Hourly HHIs were also calculated for baseload, intermediate and peaking segments of generation supply. Hourly energy market HHIs by supply curve segment were calculated based on hourly energy market shares, unadjusted for imports.

The "Merger Policy Statement" of the FERC states that a market can be broadly characterized as:

- **Unconcentrated.** Market HHI below 1000, equivalent to 10 firms with equal market shares;
- **Moderately Concentrated.** Market HHI between 1000 and 1800; and

- **Highly Concentrated.** Market HHI greater than 1800, equivalent to between five and six firms with equal market shares.[9]

PJM HHI Results

Calculations for hourly HHI indicate that by the FERC standards, the PJM Energy Market during the first three months of 2017 was unconcentrated (Table 3-2).

Table 3-2 PJM hourly energy market HHI: January 1 through March 31, 2016 and 2017[10]

	Hourly Market HHI (Jan - Mar, 2016)	Hourly Market HHI (Jan - Mar, 2017)
Average	1300	980
Minimum	1133	882
Maximum	1561	1126
Highest market share (One hour)	31%	23%
Average of the highest hourly market share	23%	17%
# Hours	2,183	2,159
# Hours HHI > 1800	0	0
% Hours HHI > 1800	0%	0%

Table 3-3 includes HHI values by supply curve segment, including base, intermediate and peaking plants for the first three months of 2016 and 2017. The PJM Energy Market was moderately concentrated overall with moderate concentration in the baseload and intermediate segments, and high concentration in the peaking segment.

Table 3-3 PJM hourly energy market HHI (By supply segment): January 1 through March 31, 2016 and 2017

	Jan - Mar, 2016			Jan - Mar, 2017		
	Minimum	Average	Maximum	Minimum	Average	Maximum
Base	990	1132	1347	840	1006	1273
Intermediate	767	1965	5603	668	1617	6764
Peak	951	6073	10000	821	6323	10000

9 77 FERC ¶ 61,263, pp. 64-70 (1996), "*Inquiry Concerning the Commission's Merger Policy under the Federal Power Act: Policy Statement.*"
10 This analysis includes all hours in the first three months of 2016 and 2017, regardless of congestion.

Figure 3-1 shows the total installed capacity (ICAP) MW of units in the baseload, intermediate and peaking segments by fuel source in the first three months of 2017.

Figure 3-1 Fuel source distribution in unit segments: January 1 through March 31, 2017[11]

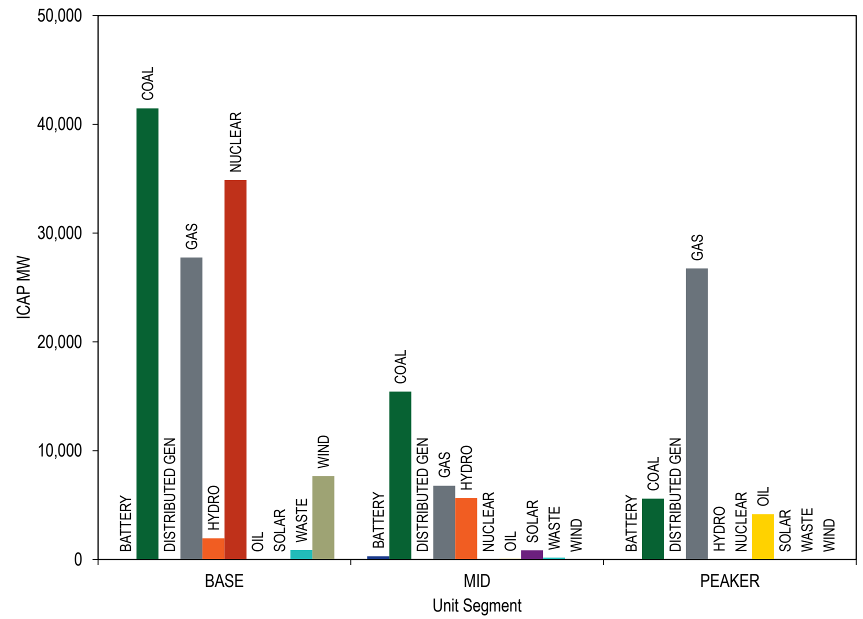
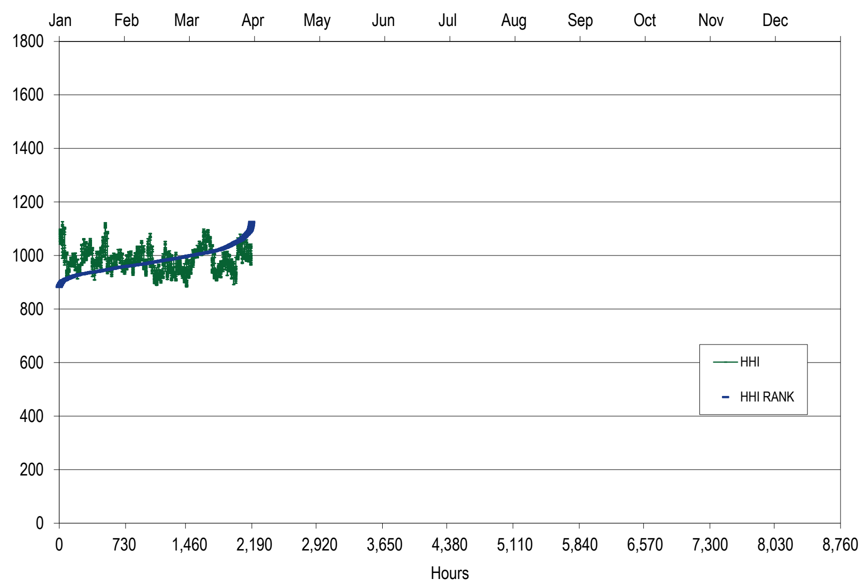


Figure 3-2 presents the hourly HHI values in chronological order and an HHI duration curve for the first three months of 2017.

11 The units classified as Distributed Gen are buses within Electric Distribution Companies (EDCs) that are modeled as generation buses to accurately reflect net energy injections from distribution level load buses. The modeling change was the outcome of the Net Energy Metering Task Force stakeholder group in July, 2012. See PJM. "Net Energy Metering Senior Task Force (NEMSTF) Action on Proposed Manual 28 Revisions," (July 26, 2012) <http://www.pjm.com/~/media/committees-groups/committees/mrc/20120726/20120726-item-04-nemstf-report-and-proposed-manual-revisions.ashx>.

Figure 3-2 PJM hourly energy market HHI: January 1 through March 31, 2017



Ownership of Marginal Resources

Table 3-4 shows the contribution to real-time, load-weighted LMP by individual marginal resource owner.[12] The contribution of each marginal resource to price at each load bus is calculated for each five-minute interval of 2017, and summed by the parent company that offers the marginal resource into the Real-Time Energy Market. In the first three months of 2017, the offers of one company resulted in 16.8 percent of the real-time, load-weighted PJM system LMP and that the offers of the top four companies resulted in 56.5percent of the real-time, load-weighted, average PJM system LMP. During the first three months of 2016, the offers of one company resulted in 25.0 percent of the real time, load-weighted PJM system LMP and offers of the top four companies resulted in 62.6 percent of the real-time, load-weighted, average PJM system LMP. In the first three months of 2017, the offers of one company resulted in 16.5 percent of the peak hour real-time, load weighted PJM system LMP. In the first three months of 2016, the offers of one company resulted in 28.1 percent of the peak hour, real-time, load weighted PJM system LMP.

12 See the *MMU Technical Reference for PJM Markets*, at "Calculation and Use of Generator Sensitivity/Unit Participation Factors."

Table 3-4 Marginal unit contribution to PJM real-time, load-weighted LMP (By parent company): January 1 through March 31, 2016 and 2017

2016 (Jan-Mar)						2017 (Jan - Mar)					
All Hours			Peak Hours			All Hours			Peak Hours		
Company	Percent of Price	Cumulative Percent	Company	Percent of Price	Cumulative Percent	Company	Percent of Price	Cumulative Percent	Company	Percent of Price	Cumulative Percent
1	25.0%	25.0%	1	28.0%	28.0%	1	16.8%	16.8%	1	16.5%	16.5%
2	16.2%	41.2%	2	18.0%	46.0%	2	16.7%	33.5%	2	16.3%	32.8%
3	10.7%	52.0%	3	10.9%	56.9%	3	14.6%	48.0%	3	13.1%	45.9%
4	10.7%	62.6%	4	8.3%	65.2%	4	8.4%	56.5%	4	7.8%	53.7%
5	8.4%	71.0%	5	7.1%	72.4%	5	6.7%	63.2%	5	7.4%	61.1%
6	7.1%	78.1%	6	6.9%	79.3%	6	4.8%	68.0%	6	6.4%	67.5%
7	2.7%	80.8%	7	3.8%	83.1%	7	4.4%	72.4%	7	4.2%	71.7%
8	2.5%	83.3%	8	2.7%	85.7%	8	3.3%	75.6%	8	2.9%	74.6%
9	2.3%	85.6%	9	2.2%	88.0%	9	2.6%	78.2%	9	2.6%	77.2%
Other (58 companies)	14.4%	100.0%	Other (51 companies)	12.0%	100.0%	Other (57 companies)	21.8%	100.0%	Other (52 companies)	22.8%	100.0%

Table 3-5 Marginal resource contribution to PJM day-ahead, load-weighted LMP (By parent company): January 1 through March 31, 2016 and 2017

2016 (Jan - Mar)						2017 (Jan - Mar)					
All Hours			Peak Hours			All Hours			Peak Hours		
Company	Percent of Price	Culmulative Percent	Company	Percent of Price	Culmulative Percent	Company	Percent of Price	Culmulative Percent	Company	Percent of Price	Culmulative Percent
1	17.0%	17.0%	1	16.5%	16.5%	1	8.9%	8.9%	1	9.6%	9.6%
2	9.7%	26.7%	2	9.7%	9.7%	2	8.9%	17.8%	2	7.6%	17.2%
3	8.1%	34.8%	3	8.7%	8.7%	3	7.3%	25.1%	3	7.3%	24.5%
4	7.4%	42.3%	4	8.6%	8.6%	4	7.0%	32.1%	4	6.5%	31.0%
5	7.1%	49.4%	5	7.2%	7.2%	5	6.3%	38.5%	5	5.4%	36.3%
6	4.8%	54.2%	6	3.5%	3.5%	6	6.1%	44.6%	6	5.4%	41.7%
7	4.5%	58.7%	7	3.3%	3.3%	7	4.5%	49.1%	7	5.0%	46.7%
8	3.9%	62.6%	8	2.8%	2.8%	8	3.9%	53.0%	8	4.6%	51.4%
9	2.7%	65.3%	9	2.8%	2.8%	9	3.0%	56.0%	9	3.8%	55.2%
Other (137 companies)	34.7%	100.0%	Other (128 companies)	36.9%	36.9%	Other (126 companies)	44.0%	100.0%	Other (122 companies)	44.8%	100.0%

Table 3-5 shows the contribution to day-ahead, load-weighted LMP by individual marginal resource owners.[13] The contribution of each marginal resource to price at each load bus is calculated hourly, and summed by the parent company that offers the marginal resource into the Day-Ahead Energy Market. The results show that in the first three months of 2017, the offers of one company contributed 8.9 percent of the day-ahead, load-weighted PJM system LMP and that the offers of the top four companies contributed 32.1 percent of the day-ahead, load-weighted, average PJM system LMP. In the first three months of 2016, the offers of one company contributed 17.0 percent of the day-ahead, load-weighted PJM system LMP and offers of the top four companies contributed 42.3 percent of the day-ahead, load-weighted, average PJM system LMP.

Type of Marginal Resources

LMPs result from the operation of a market based on security-constrained, least-cost dispatch in which marginal resources determine system LMPs, based on their offers. Marginal resource designation is not limited to physical resources in the Day-Ahead Energy Market. INC offers, DEC bids and up to congestion transactions are dispatchable injections and withdrawals in the Day-Ahead Energy Market that can set price via their offers and bids.

Table 3-6 shows the type of fuel used by marginal resources in the Real-Time Energy Market. There can be more than one marginal resource in any given interval as a result of transmission constraints. In the first three months of 2017, coal units were 34.23 percent and natural gas units were 51.05 percent of marginal resources. In the first three months of 2016, coal units were

13 See the *MMU Technical Reference for PJM Markets*, at "Calculation and Use of Generator Sensitivity/Unit Participation Factors."

45.86 percent and natural gas units were 42.03 percent of the total marginal resources. In the first three months of 2017, 80.1 percent of the wind marginal units had negative offer prices, 4.0 percent had zero offer prices and 15.9 percent had positive offer prices.

The results reflect the dynamics of an LMP market. When there is a single constraint, there are two marginal units. For example, a significant west to east constraint could be binding with a gas unit marginal in the east and a coal unit marginal in the west. As a result, although the dispatch of natural gas units has increased and gas units set price for more hours as marginal resources in the Real-Time Energy Market, this does not necessarily reduce the proportion of hours in which coal units are marginal.[14]

The proportion of marginal nuclear units increased from 0.09 percent in the first three months of 2016 to 0.78 percent in the first three months of 2017. The increase was primarily due to a small number of nuclear units offering with a dispatchable range. Most nuclear units are offered as fixed generation in the PJM market. The dispatchable nuclear units do not always respond to dispatch instructions.

Table 3-6 Type of fuel used (By real-time marginal units): January 1 through March 31, 2013 through 2017

	Jan-Mar				
Type/Fuel	2013	2014	2015	2016	2017
Gas	32.40%	42.61%	33.10%	42.03%	51.05%
Coal	57.74%	46.59%	57.21%	45.86%	34.23%
Wind	4.76%	5.17%	2.91%	4.06%	7.05%
Oil	4.79%	4.53%	6.29%	7.65%	6.56%
Uranium	0.02%	0.15%	0.01%	0.09%	0.78%
Other	0.02%	0.76%	0.43%	0.20%	0.26%
Municipal Waste	0.07%	0.03%	0.05%	0.11%	0.07%
Emergency DR	0.02%	0.15%	0.00%	0.00%	0.00%

Figure 3-3 shows the type of fuel used by marginal resources in the Real-Time Energy Market since 2004. The role of coal as a marginal resource has declined while the role of gas as a marginal resource has increased.

Figure 3-3 Type of fuel used (By real-time marginal units): January 1 through March 31, 2004 through 2017

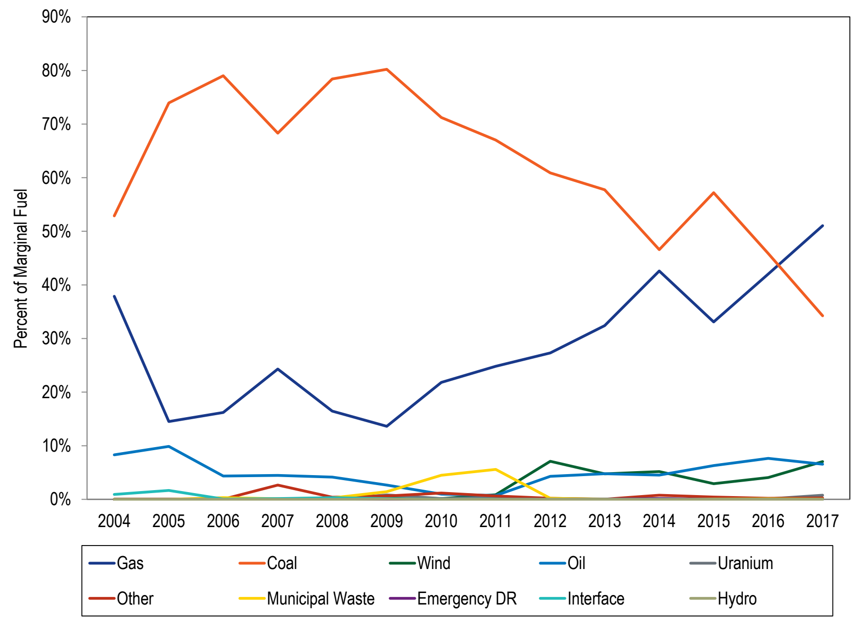


Table 3-7 shows the type and fuel type where relevant, of marginal resources in the Day-Ahead Energy Market. In the first three months of 2017, up to congestion transactions were 83.70 percent of marginal resources. Up to congestion transactions were 83.21 percent of marginal resources in the first three months of 2016.

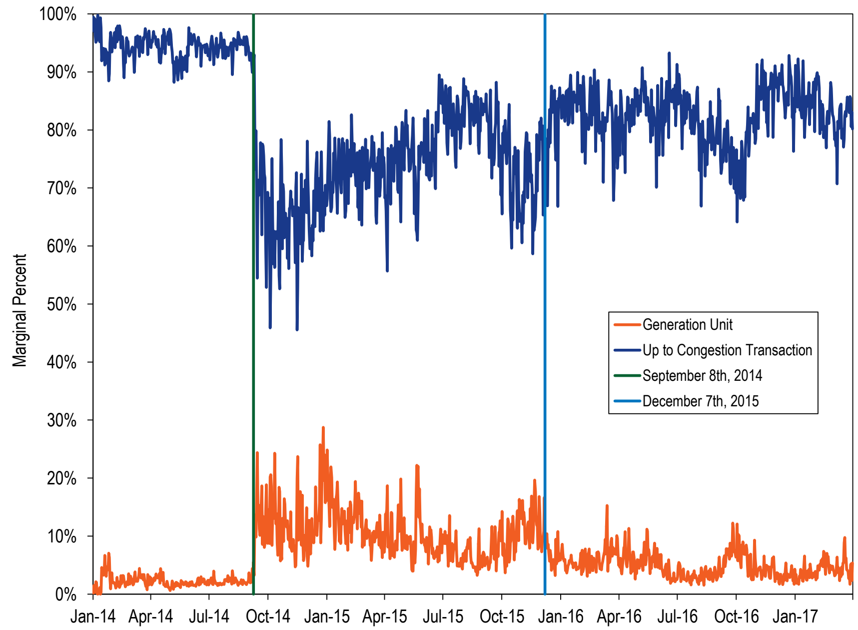
14 Prior to April 1, 2015, for the generation units that are capable of using multiple fuel types, PJM did not require the participants to disclose the fuel type associated with their offer schedule. For these units, the cleared offer schedules on a given day were compared to the cost associated with each fuel to determine the fuel type most likely to have been the basis for the cleared schedule.

Table 3-7 Day-ahead marginal resources by type/fuel: January 1 through March 31, 2011 through 2017

	(Jan - Mar)						
Type/Fuel	2011	2012	2013	2014	2015	2016	2017
Up to Congestion Transaction	65.72%	84.85%	93.54%	94.68%	94.68%	83.21%	83.70%
DEC	14.80%	5.78%	1.71%	1.60%	1.60%	6.86%	7.62%
INC	9.08%	5.51%	1.44%	1.07%	1.07%	3.99%	4.57%
Coal	7.43%	2.70%	2.26%	1.27%	1.27%	2.76%	1.71%
Gas	2.40%	0.95%	0.92%	1.08%	1.08%	2.44%	1.80%
Oil	0.00%	0.00%	0.00%	0.04%	0.04%	0.59%	0.38%
Dispatchable Transaction	0.27%	0.08%	0.09%	0.19%	0.19%	0.06%	0.04%
Wind	0.00%	0.03%	0.02%	0.05%	0.05%	0.04%	0.16%
Uranium	0.00%	0.00%	0.00%	0.00%	0.00%	0.04%	0.02%
Other	0.00%	0.00%	0.00%	0.00%	0.00%	0.01%	0.00%
Municipal Waste	0.02%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Total	100.00%	100.00%	99.99%	100.00%	100.00%	100.00%	100.00%

Figure 3-4 shows, for the Day-Ahead Market from January 1, 2014, through March 31, 2017, the daily proportion of marginal resources that were up to congestion transaction and/or generation units. The percent of marginal up to congestion transactions decreased significantly beginning on September 8, 2014, as a result of the FERC's UTC uplift refund notice which became effective on that date.[15] The percent of marginal up to congestion transaction decreased and that of generation units increased. That trend has reversed as a result of the expiration of the fifteen month uplift refund period for UTC transactions.

Figure 3-4 Day-ahead marginal up to congestion transaction and generation units: January 1, 2014 through March 31, 2017



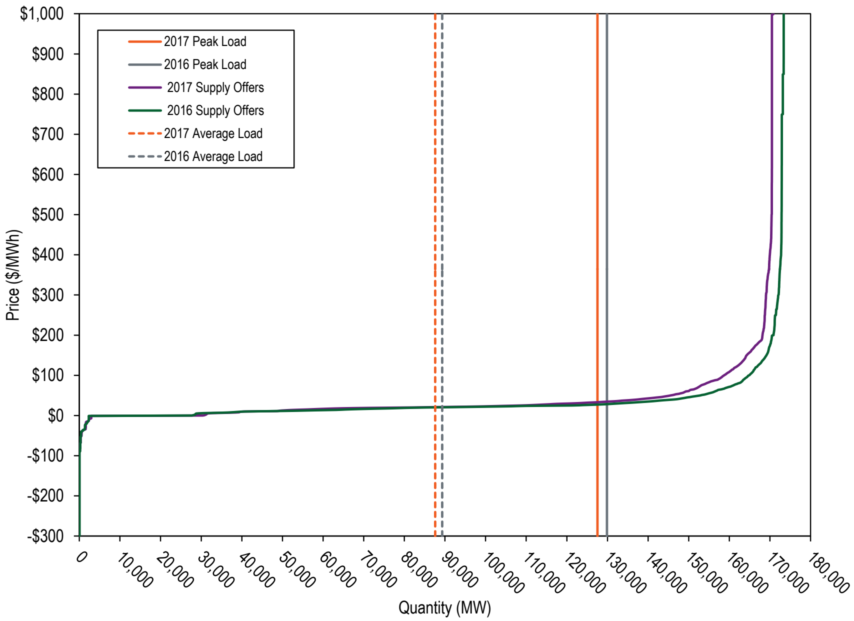
Supply

Supply includes physical generation and imports and virtual transactions.

Figure 3-5 shows the average PJM aggregate real-time generation supply curves by offer price, peak load and average load for the first three months of 2016 and 2017. The maximum of average offered real-time generation decreased by 2,613 MW, or 1.5 percent, from 173,439 MW in the first three months of 2016 to 170,827 MW in the first three months of 2016.

15 See 18 CFR § 385.213 (2014).

Figure 3-5 Average PJM aggregate real-time generation supply curves by offer price: January 1 through March 31, 2016 and 2017



Energy Production by Fuel Source

Table 3-8 shows PJM generation by fuel source in GWh for the first three months of 2016 and 2017. In the first three months of 2017, generation from coal units increased 7.0 percent and generation from natural gas units increased 1.3 percent compared to the first three months of 2016.[16]

Table 3-8 PJM generation (By fuel source (GWh)): January 1 through March 31, 2016 and 2017[17 18]

Jan - Mar		2016		2017		Change in
		GWh	Percent	GWh	Percent	Output
Coal		62,503.2	32.0%	66,884.2	33.3%	7.0%
	Bituminous	56,062.4	28.7%	57,284.4	28.5%	2.2%
	Sub Bituminous	5,089.0	2.6%	7,383.4	3.7%	45.1%
	Other Coal	1,351.8	0.7%	2,216.3	1.1%	64.0%
Nuclear		71,578.3	36.6%	71,964.8	35.8%	0.5%
Gas		48,989.1	25.1%	49,673.5	24.7%	1.4%
	Natural Gas	48,453.7	24.8%	49,074.8	24.4%	1.3%
	Landfill Gas	535.3	0.3%	598.1	0.3%	11.7%
	Other Gas	0.1	0.0%	0.6	0.0%	950.0%
Hydroelectric		4,156.8	2.1%	3,618.7	1.8%	(12.9%)
	Pumped Storage	975.6	0.5%	905.9	0.5%	(7.2%)
	Run of River	2,825.7	1.4%	2,372.6	1.2%	(16.0%)
	Other Hydro	355.5	0.2%	340.2	0.2%	(4.3%)
Wind		5,802.7	3.0%	6,573.7	3.3%	13.3%
Waste		979.4	0.5%	957.1	0.5%	(2.3%)
	Solid Waste	979.4	0.5%	957.1	0.5%	(2.3%)
	Miscellaneous	0.0	0.0%	0.0	0.0%	NA
Oil		617.2	0.3%	481.3	0.2%	(22.0%)
	Heavy Oil	137.7	0.1%	3.6	0.0%	(97.4%)
	Light Oil	142.0	0.1%	87.3	0.0%	(38.5%)
	Diesel	26.4	0.0%	7.1	0.0%	(73.0%)
	Gasoline	0.0	0.0%	0.0	0.0%	NA
	Kerosene	65.5	0.0%	0.8	0.0%	(98.7%)
	Jet Oil	0.0	0.0%	0.0	0.0%	NA
	Other Oil	245.5	0.1%	382.4	0.2%	55.8%
Solar, Net Energy Metering		181.3	0.1%	267.8	0.1%	47.8%
Energy Storage		4.2	0.0%	9.2	0.0%	118.5%
	Battery	4.2	0.0%	9.2	0.0%	118.5%
	Compressed Air	0.0	0.0%	0.0	0.0%	NA
Biofuel		516.9	0.3%	493.0	0.2%	(4.6%)
Geothermal		0.0	0.0%	0.0	0.0%	NA
Other Fuel Type		0.0	0.0%	48.2	0.0%	NA
Total		195,329.0	100.0%	200,971.5	100.0%	2.9%

16 Generation data are the sum of MWh for each fuel by source at every generation bus in PJM with positive output and reflect gross generation without offset for station use of any kind.

17 All generation is total gross generation output and does not net out the MWh withdrawn at a generation bus to provide auxiliary/parasitic power or station power, power to synchronous condenser motors, or power to run pumped storage pumps.

18 Net Energy Metering is combined with Solar due to data confidentiality reasons.

Table 3-9 Monthly PJM generation (By fuel source (GWh)): January 1 through March 31, 2017

	Jan	Feb	Mar	Total
Coal	25,111.3	19,246.2	22,526.7	66,884.2
Bituminous	21,142.1	16,596.5	19,545.7	57,284.4
Sub Bituminous	3,189.9	1,945.5	2,248.1	7,383.4
Other Coal	779.3	704.2	732.9	2,216.3
Nuclear	26,016.6	22,140.8	23,807.5	71,964.8
Gas	16,071.3	15,213.3	18,388.9	49,673.5
Natural Gas	15,884.4	15,017.6	18,172.8	49,074.8
Landfill Gas	186.9	195.7	215.6	598.1
Other Gas	0.0	0.1	0.6	0.6
Hydroelectric	1,266.9	1,083.6	1,268.2	3,618.7
Pumped Storage	335.8	252.3	317.8	905.9
Run of River	811.4	731.2	830.0	2,372.6
Other Hydro	119.8	100.0	120.4	340.2
Wind	2,017.5	2,178.6	2,377.6	6,573.7
Waste	364.9	281.5	310.7	957.1
Solid Waste	364.9	281.5	310.7	957.1
Miscellaneous	0.0	0.0	0.0	0.0
Oil	210.9	152.6	117.8	481.3
Heavy Oil	0.5	3.1	0.0	3.6
Light Oil	59.7	21.8	5.8	87.3
Diesel	6.0	0.1	1.1	7.1
Gasoline	0.0	0.0	0.0	0.0
Kerosene	0.8	0.0	0.1	0.8
Jet Oil	0.0	0.0	0.0	0.0
Other Oil	144.0	127.6	110.9	382.4
Solar, Net Energy Metering	52.6	93.1	122.1	267.8
Energy Storage	2.6	3.2	3.5	9.2
Battery	2.6	3.2	3.5	9.2
Compressed Air	0.0	0.0	0.0	0.0
Biofuel	152.7	158.3	182.0	493.0
Geothermal	0.0	0.0	0.0	0.0
Other Fuel Type	48.2	0.0	0.0	48.2
Total	71,315.5	60,551.1	69,104.8	200,971.5

Figure 3-6 shows the fuel diversity index (FDI_e) for PJM energy generation.[19] The FDI_e is defined as $1 - \sum_{i=1}^{N} s_i^2$

where s_i is the share of fuel type i. The minimum possible value for the FDI_e is zero, corresponding to all generation from a single fuel type. The maximum possible value for the FDI_e is achieved when each fuel type has an equal share of total generation. For a generation fleet composed of 10 fuel types, the maximum achievable index is 0.9. The fuel type categories used in the calculation of the FDI_e are the 10 primary fuel sources in Table 3-8 with nonzero generation values. The FDI_e exhibits seasonality with most of the peaks occurring in the spring and summer months, and the valleys occurring in the fall and winter months. A significant drop in the FDI_e occurred in fall of 2004 as a result of the expansion of the PJM market footprint into ComEd, AEP, and Dayton Power & Light control zones and the increased shares of coal and nuclear that resulted.[20] The increasing trend that begins in 2008 corresponds with a period of decreasing coal generation and increasing gas generation. Coal generation as a share of total generation dropped 20.5 percentage points from 2008 to 2016, and gas generation as a share of total generation increased 19.3 percentage points. Wind generation, at 2.2 percent of total generation in 2016, also contributes to the rising trend. The average FDI_e increased 0.2 percent from the first three months of 2016 to the first three months of 2017.

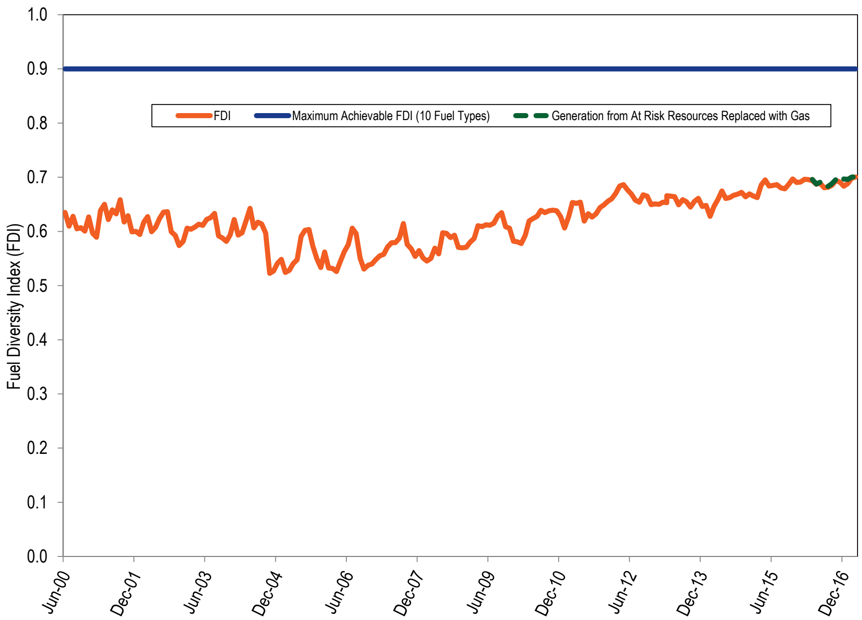
The FDI_e was used to measure the impact of potential retirements by resources that have been identified as being at risk of retirement by the MMUs net revenue adequacy analysis.[21] There were 96 resources with installed capacity totaling 14,500 MW identified as at risk. These 96 resources generated 43 GW in the twelve month period ending March 31, 2017. The dashed line in Figure 3-6 shows the FDI_e calculated assuming that the 43 GW of generation from the 96 at risk resources were replaced by gas generation. The FDI_e under these assumptions would have increased in eleven of the twelve months with an average monthly increase of 0.4 percent over the actual FDI_e.

19 Monitoring Analytics developed the FDI to provide an objective metric of fuel diversity. The FDI metric is similar to the HHI used to measure market concentration. The FDI is calculated separately for energy output and for installed capacity.

20 See the *2016 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography" for an explanation of the expansion of the PJM footprint. The integration of the ComEd Control Area occurred in May 2004 and the integration of the AEP and Dayton control zones occurred in October 2004.

21 See the *2016 State of the Market Report for PJM*, Volume 2, Section 7: Net Revenue, Units at Risk.

Figure 3-6 Fuel diversity index for PJM monthly generation: June 1, 2000 through March 31, 2017



Net Generation and Load

PJM sums all negative (injections) and positive (withdrawals) load at each designated load bus when calculating net load (accounting load). PJM sums all of the negative (withdrawals) and positive (injections) generation at each generation bus when calculating net generation. Netting withdrawals and injections by bus type (generation or load) affects the measurement of total load and total generation. Energy withdrawn at a generation bus to provide, for example, auxiliary/parasitic power or station power, power to synchronous condenser motors, or power to run pumped storage pumps, is actually load, not negative generation. Energy injected at load buses by behind the meter generation is actually generation, not negative load.

The zonal load-weighted LMP is calculated by weighting the zone's load bus LMPs by the zone's load bus accounting load. The definition of injections and withdrawals of energy as generation or load affects PJM's calculation of zonal load-weighted LMP.

The MMU recommends that during hours when a generation bus shows a net withdrawal, the energy withdrawal be treated as load, not negative generation, for purposes of calculating load and load-weighted LMP. The MMU also recommends that during hours when a load bus shows a net injection, the energy injection be treated as generation, not negative load, for purposes of calculating generation and load-weighted LMP.

Real-Time Supply

The maximum of average offered real-time generation decreased by 2,613 MW, or 1.5 percent, from 173,439 MW in the first three months of 2016 to 170,827 MW in the first three months of 2017.[22]

In 2016, 5,421.4 MW of new capacity resources were added. In 2016, 395.5 MW were retired.

PJM average real-time cleared generation in the first three months of 2017 increased by 2.9 percent from first three months of 2016, from 88,470 MW to 91,074 MW.[23]

PJM average real-time cleared supply including imports increased by 0.8 percent in 2016 from 2015, from 94,329 MW to 95,054 MW.

In the PJM Real-Time Energy Market, there are three types of supply offers:

- **Self-Scheduled Generation Offer.** Offer to supply a fixed block of MWh, as a price taker, from a unit that may also have a dispatchable component above the minimum.
- **Dispatchable Generation Offer.** Offer to supply a schedule of MWh and corresponding offer prices from a specific unit.

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

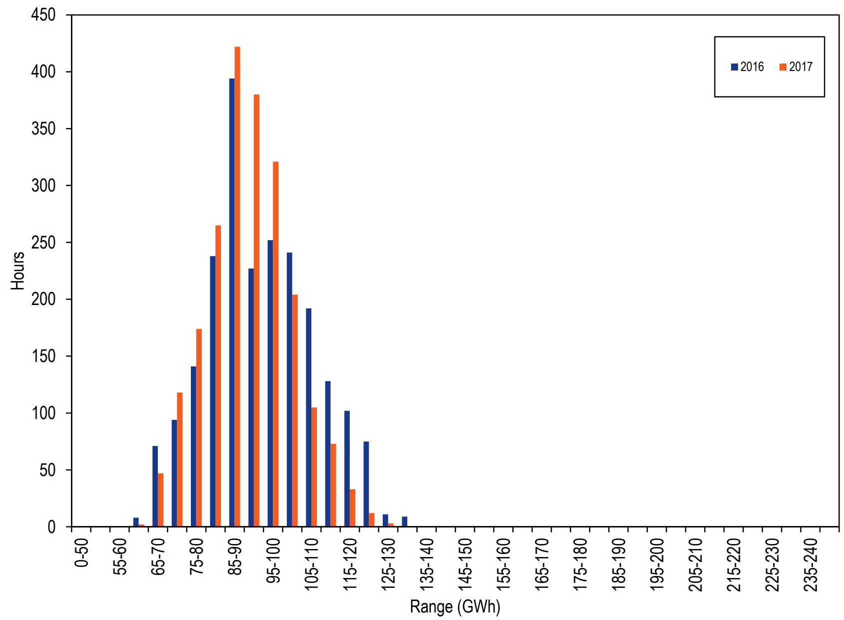
23 Generation data are the net MWh injections and withdrawals MWh at every generation bus in PJM.

- **Import.** An import is an external energy transaction scheduled to PJM from another balancing authority. A real-time import must have a valid OASIS reservation when offered, must have available ramp room to support the import, must be accompanied by a NERC Tag, and must pass the neighboring balancing authority checkout process.

PJM Real-Time Supply Duration

Figure 3-7 shows the hourly distribution of PJM real-time generation plus imports for the first three months of 2016 and 2017.

Figure 3-7 Distribution of PJM real-time generation plus imports: January 1 through March 31, 2016 and 2017[24]



24 Each range on the horizontal axis excludes the start value and includes the end value.

PJM Real-Time, Average Supply

Table 3-10 presents summary real-time supply statistics for each year for the 18-year period from 2000 through 2017.[25]

Table 3-10 PJM real-time average hourly generation and real-time average hourly generation plus average hourly imports: January 1 through March 31, 2000 through 2017

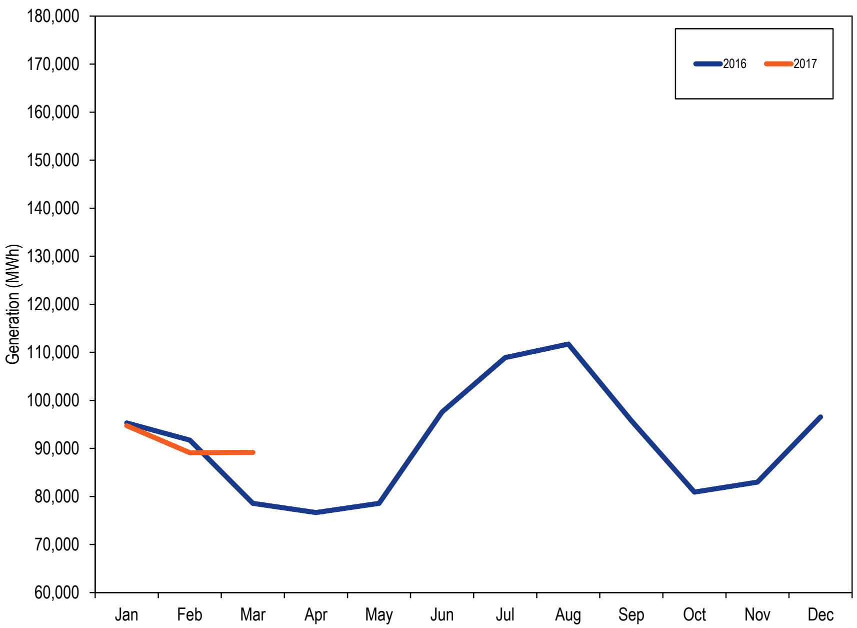
	PJM Real-Time Supply (MWh)				Year-to-Year Change			
	Generation		Generation Plus Imports		Generation		Generation Plus Imports	
Jan-Mar	Generation	Standard Deviation	Supply	Standard Deviation	Generation	Standard Deviation	Supply	Standard Deviation
2000	NA	NA	NA	NA	NA	NA	NA	NA
2001	30,923	3,488	33,806	3,358	NA	NA	NA	NA
2002	27,948	3,416	31,465	3,508	(9.6%)	(2.1%)	(6.9%)	4.5%
2003	38,731	5,187	42,498	5,092	38.6%	51.8%	35.1%	45.1%
2004	37,790	4,660	41,960	4,899	(2.4%)	(10.2%)	(1.3%)	(3.8%)
2005	74,187	8,269	80,184	9,017	96.3%	77.4%	91.1%	84.1%
2006	82,550	7,921	87,729	8,565	11.3%	(4.2%)	9.4%	(5.0%)
2007	86,286	10,018	91,454	11,351	4.5%	26.5%	4.2%	32.5%
2008	86,690	9,375	92,075	10,150	0.5%	(6.4%)	0.7%	(10.6%)
2009	81,987	11,417	88,148	12,213	(5.4%)	21.8%	(4.3%)	20.3%
2010	81,676	12,801	87,009	13,236	(0.4%)	12.1%	(1.3%)	8.4%
2011	83,505	10,116	88,750	10,884	2.2%	(21.0%)	2.0%	(17.8%)
2012	88,068	11,177	93,128	11,685	5.5%	10.5%	4.9%	7.4%
2013	92,776	10,030	98,002	10,812	5.3%	(10.3%)	5.2%	(7.5%)
2014	100,655	12,427	106,879	13,255	8.5%	23.9%	9.1%	22.6%
2015	97,741	13,085	105,027	14,350	(2.9%)	5.3%	(1.7%)	8.3%
2016	88,470	12,666	94,383	13,890	(9.5%)	(3.2%)	(10.1%)	(3.2%)
2017	91,074	11,009	91,074	11,009	2.9%	(13.1%)	(3.5%)	(20.7%)

25 The import data in this table is not available before June 1, 2000. The data that includes imports in 2000 is calculated from the last six months of that year.

PJM Real-Time, Monthly Average Generation

Figure 3-8 compares the real-time, monthly average hourly generation in 2016 and the first three months of 2017.

Figure 3-8 PJM real-time average monthly hourly generation: January 1, 2016 through March 31, 2017



Day-Ahead Supply

PJM average day-ahead supply in the first three months of 2017, including INCs and up to congestion transactions, increased by 5.6 percent from the first three months of 2016, from 133,263 MW to 140,756 MW.

PJM average day-ahead supply in the first three months of 2017, including INCs, up to congestion transactions, and imports, increased by 3.8 percent from the first three months of 2016, from 135,638 MW to 140,756 MW. The increase in PJM day-ahead supply was a result of an increase in UTCs beginning in December 2015 based on a FERC order setting December 8, 2015, as the last effective date for any uplift charges subsequently assigned to UTCs.[26]

In the PJM Day-Ahead Energy Market, there are five types of financially binding supply offers:

- **Self-Scheduled Generation Offer.** Offer to supply a fixed block of MWh, as a price taker, from a unit that may also have a dispatchable component above the minimum.
- **Dispatchable Generation Offer.** Offer to supply a schedule of MWh and corresponding offer prices from a unit.
- **Increment Offer (INC).** Financial offer to supply MWh and corresponding offer prices. INCs can be submitted by any market participant.
- **Up to Congestion Transaction (UTC).** Conditional transaction that permits a market participant to specify a maximum price spread between the transaction source and sink. An up to congestion transaction is evaluated as a matched pair of an injection and a withdrawal analogous to a matched pair of an INC offer and a DEC bid.
- **Import.** An import is an external energy transaction scheduled to PJM from another balancing authority. An import must have a valid willing to pay congestion (WPC) OASIS reservation when offered. An import energy transaction that clears the Day-Ahead Energy Market is financially binding. There is no link between transactions submitted in the PJM Day-Ahead Energy Market and the PJM Real-Time Energy Market, so an import energy transaction approved in the Day-Ahead Energy Market will not physically flow in real time unless it is also submitted through the real-time energy market scheduling process.

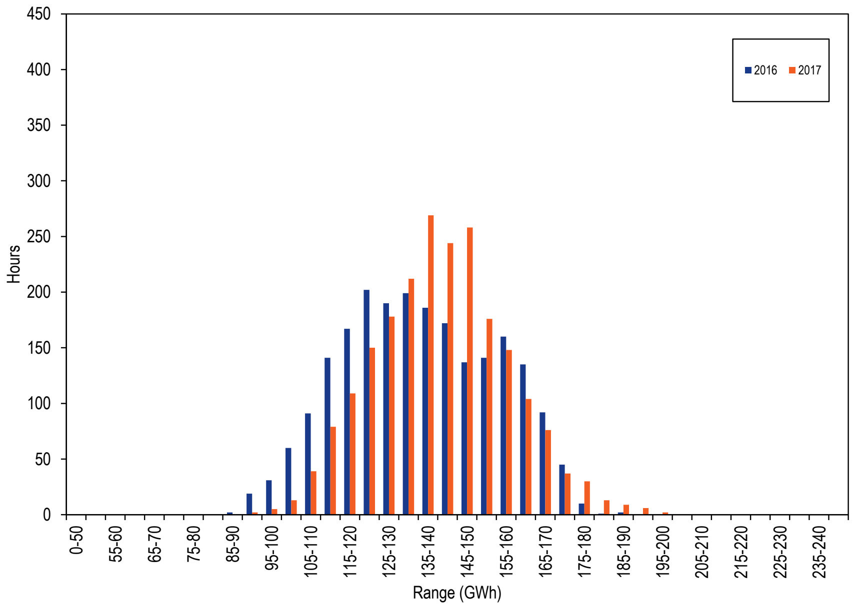
PJM Day-Ahead Supply Duration

Figure 3-9 shows the hourly distribution of PJM day-ahead supply, including increment offers, up to congestion transactions, and imports for 2015 and 2016. There was an increase in up to congestion volume, which resulted in an increase in day-ahead supply, as a result of the expiration of the fifteen month

26 148 FERC ¶ 61,144 (2014).

potential refund period for uplift charges for UTC transactions on December 7, 2015.

Figure 3-9 Distribution of PJM day-ahead supply plus imports: January 1 through March 31, 2016 and 2017[27]



PJM Day-Ahead, Average Supply

Table 3-11 presents summary day-ahead supply statistics for each year of the 18-year period from 2000 through 2017.[28]

Table 3-11 PJM day-ahead average hourly supply and day-ahead average hourly supply plus average hourly imports: January 1 through March 31, 2000 through 2017

	PJM Day-Ahead Supply (MWh)				Year-to-Year Change			
	Supply		Supply Plus Imports		Supply		Supply Plus Imports	
Jan-Mar	Supply	Standard Deviation	Supply	Standard Deviation	Supply	Standard Deviation	Supply	Standard Deviation
2000	NA	NA	NA	NA	NA	NA	NA	NA
2001	28,494	2,941	29,252	3,021	NA	NA	NA	NA
2002	20,274	10,131	20,827	10,134	(28.8%)	244.5%	(28.8%)	235.5%
2003	37,147	4,337	37,807	4,389	83.2%	(57.2%)	81.5%	(56.7%)
2004	46,591	4,794	47,377	5,039	25.4%	10.5%	25.3%	14.8%
2005	89,011	9,434	90,502	9,443	91.0%	96.8%	91.0%	87.4%
2006	97,319	9,035	99,551	9,061	9.3%	(4.2%)	10.0%	(4.0%)
2007	110,099	11,938	112,561	12,141	13.1%	32.1%	13.1%	34.0%
2008	109,711	10,479	112,165	10,671	(0.4%)	(12.2%)	(0.4%)	(12.1%)
2009	104,880	13,895	107,325	14,031	(4.4%)	32.6%	(4.3%)	31.5%
2010	101,733	13,835	104,858	13,917	(3.0%)	(0.4%)	(2.3%)	(0.8%)
2011	110,310	12,200	112,854	12,419	8.4%	(11.8%)	7.6%	(10.8%)
2012	132,178	13,701	134,405	13,804	19.8%	12.3%	19.1%	11.2%
2013	147,246	13,054	149,300	13,244	11.4%	(4.7%)	11.1%	(4.1%)
2014	168,373	11,875	170,778	11,935	14.3%	(9.0%)	14.4%	(9.9%)
2015	123,424	14,671	125,973	14,915	(26.7%)	23.5%	(26.2%)	25.0%
2016	133,263	19,105	135,638	19,405	8.0%	30.2%	7.7%	30.1%
2017	140,756	16,933	140,756	16,933	5.6%	(11.4%)	3.8%	(12.7%)

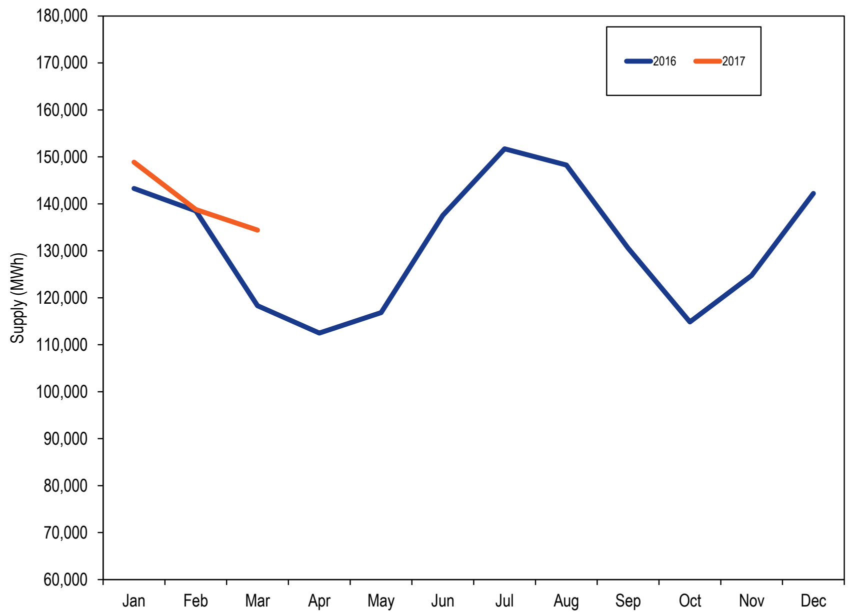
PJM Day-Ahead, Monthly Average Supply

Figure 3-10 compares the day-ahead, monthly average hourly supply, including increment offers and up to congestion transactions, for 2016 and the first three months of 2017.

27 Each range on the horizontal axis excludes the start value and includes the end value.

28 Since the Day-Ahead Energy Market did not start until June 1, 2000, the day-ahead data for 2000 only includes data for the last six months of that year.

Figure 3-10 PJM day-ahead monthly average hourly supply: January 1, 2016 through March 31, 2017



Real-Time and Day-Ahead Supply

Table 3-12 presents summary statistics for the first three months of 2016 and 2017, for day-ahead and real-time supply. All data are cleared MW. The last two columns of Table 3-12 are the day-ahead supply minus the real-time supply. The first of these columns is the total day-ahead supply less the total real-time supply and the second of these columns is the total physical day-ahead generation less the total physical real-time generation. In the first three months of 2017, up-to congestion transactions were 27.1 percent of the total day-ahead supply compared to 29.9 percent in the first three months of 2016.

Table 3-12 Day-ahead and real-time supply (MW): January 1 through March 31, 2016 and 2017

		Day Ahead					Real Time		Day Ahead Less Real Time	
	(Jan-Mar)	Generation	INC Offers	Up-to Congestion	Imports	Total Supply	Generation	Total Supply	Total Supply	Total Generation
Average	2016	91,348	5,202	36,705	2,375	135,638	88,470	94,383	41,255	2,877
	2017	92,125	6,115	42,516	1,323	142,079	91,074	94,388	47,692	1,051
Median	2016	90,440	5,070	36,131	2,296	134,690	87,392	93,082	41,607	3,048
	2017	91,972	6,111	42,702	1,363	141,842	90,623	93,731	48,111	1,349
Standard Deviation	2016	14,074	948	7,490	526	19,405	12,666	13,890	5,515	1,408
	2017	11,876	1,098	7,515	243	16,947	11,009	11,673	5,274	867
Peak Average	2016	98,217	5,357	38,741	2,479	144,832	94,434	100,852	43,980	3,783
	2017	98,367	6,626	45,126	1,271	151,390	96,856	100,304	51,086	1,512
Peak Median	2016	98,337	5,182	37,989	2,389	144,990	94,091	100,313	44,677	4,246
	2017	97,245	6,591	44,873	1,342	150,120	95,955	99,413	50,707	1,291
Peak Standard Deviation	2016	11,631	939	7,506	598	16,837	10,883	12,107	4,730	748
	2017	8,655	984	6,733	254	13,142	8,226	9,039	4,104	429
Off-Peak Average	2016	85,097	5,061	34,852	2,281	127,274	83,044	88,498	38,776	2,053
	2017	86,324	5,641	40,090	1,372	133,426	85,700	88,889	44,537	624
Off-Peak Median	2016	83,797	4,977	34,172	2,248	125,757	81,979	87,218	38,539	1,817
	2017	85,365	5,575	40,154	1,398	132,181	84,759	87,856	44,324	606
Off-Peak Standard Deviation	2016	13,165	934	6,980	430	17,737	11,702	12,748	4,989	1,463
	2017	11,519	980	7,392	223	15,436	10,538	11,148	4,288	981

Figure 3-11 shows the average hourly cleared volumes of day-ahead supply and real-time supply for the first three months of 2017. The day-ahead supply consists of cleared MW of day-ahead generation, imports, increment offers and up to congestion transactions. The real-time generation includes generation and imports.

Figure 3-11 Day-ahead and real-time supply (Average hourly volumes): January 1 through March 31, 2017

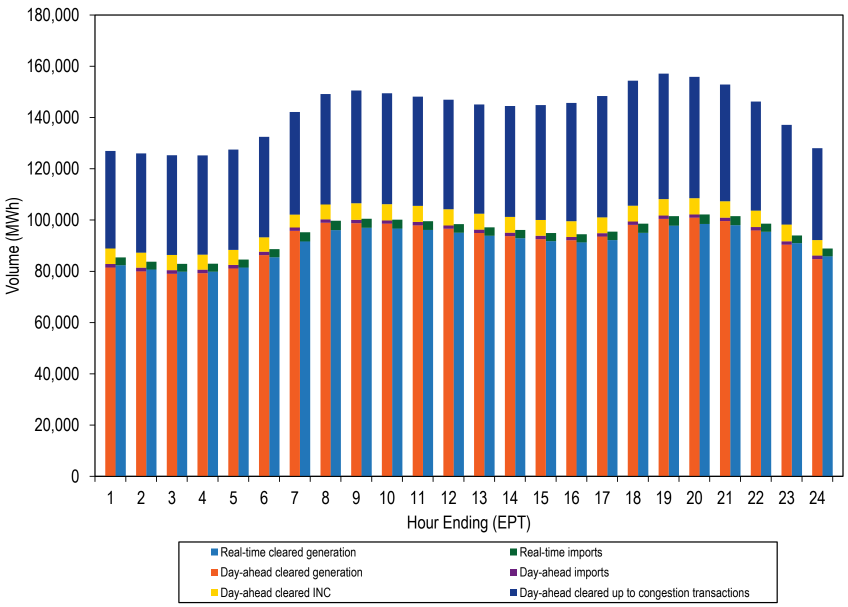


Figure 3-12 Difference between day-ahead and real-time supply (Average daily volumes): January 1, 2016 through March 31, 2017

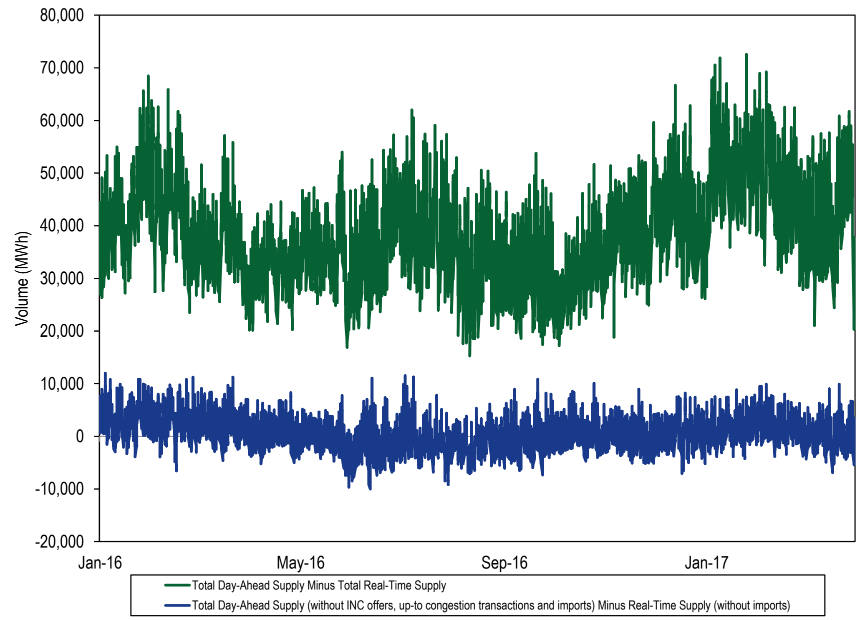
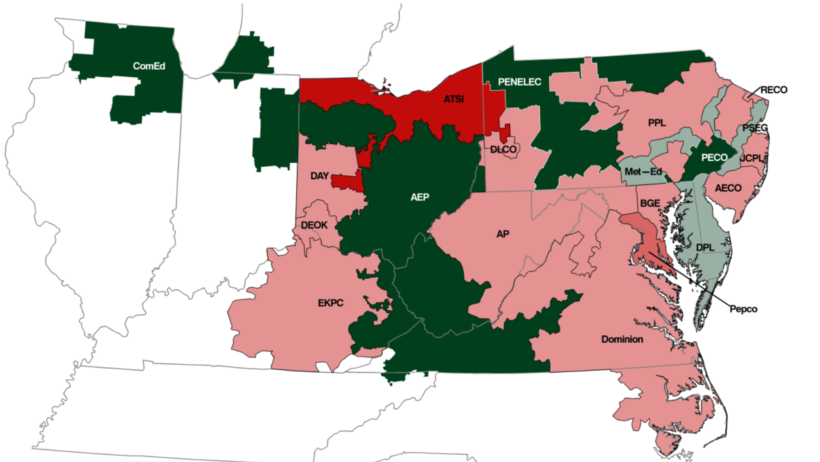


Figure 3-12 shows the difference between the day-ahead and real-time average daily supply for 2016 and the first three months of 2017.

Figure 3-13 shows the difference between the PJM real-time generation and real-time load by zone in the first three months of 2017. Figure 3-13 is color coded on a scale on which red shades represent zones that have less generation than load and green shades represent zones that have more generation than load, with darker shades meaning greater amounts of net generation or load. For example, the Pepco Control Zone has less generation than load, while the PENELEC Control Zone has more generation than load. Table 3-13 shows the difference between the PJM real-time generation and real-time load by zone in the first three months of 2016 and 2017.

Figure 3-13 Map of PJM real-time generation, less real-time load, by zone: January 1 through March 31, 2017[29]



Zone	Net Gen Minus Load (GWh)	Zone	Net Gen Minus Load (GWh)	Zone	Net Gen Minus Load (GWh)	Zone	Net Gen Minus Load (GWh)
AECO	(494)	ComEd	8,574	DPL	(2,957)	PENELEC	7,484
AEP	8,075	DAY	(1,876)	EKPC	(1,247)	Pepco	(5,489)
AP	(917)	DEOK	(884)	JCPL	(989)	PPL	(7)
ATSI	(7,949)	DLCO	1,017	Met-Ed	1,334	PSEG	919
BGE	(3,270)	Dominion	(520)	PECO	7,024	RECO	(323)

Table 3-13 PJM real-time generation less real-time load by zone (GWh): January 1 through March 31, 2016 and 2017

	Zonal Generation and Load (GWh)					
	2016 (Jan - Mar)			2017 (Jan - Mar)		
Zone	Generation	Load	Net	Generation	Load	Net
AECO	1,649.8	2,276.3	(626.4)	1,726.5	2,220.9	(494.4)
AEP	33,313.9	32,946.3	367.6	39,504.4	31,429.8	8,074.7
AP	11,506.0	12,767.4	(1,261.4)	11,419.3	12,336.2	(916.9)
ATSI	9,757.6	16,688.1	(6,930.6)	8,521.5	16,470.2	(7,948.7)
BGE	4,963.0	7,988.7	(3,025.7)	4,223.0	7,493.1	(3,270.2)
ComEd	30,737.3	23,440.7	7,296.6	31,476.1	22,902.6	8,573.5
DAY	3,853.0	4,316.3	(463.3)	2,319.9	4,196.4	(1,876.5)
DEOK	2,818.6	6,654.2	(3,835.6)	5,482.3	6,365.9	(883.5)
DLCO	4,262.6	3,348.5	914.1	4,280.2	3,262.9	1,017.3
Dominion	25,147.3	24,387.2	760.1	22,862.1	23,381.9	(519.8)
DPL	1,600.2	4,594.7	(2,994.5)	1,502.7	4,459.8	(2,957.1)
EKPC	2,478.2	3,471.6	(993.4)	1,932.4	3,179.9	(1,247.5)
JCPL	3,992.9	5,339.8	(1,346.9)	4,267.2	5,256.3	(989.2)
Met-Ed	5,758.7	3,878.3	1,880.4	5,181.9	3,848.1	1,333.8
PECO	16,178.3	9,721.3	6,457.0	16,736.6	9,712.9	7,023.6
PENELEC	8,625.1	4,369.6	4,255.5	11,845.7	4,361.5	7,484.1
Pepco	2,218.3	7,489.0	(5,270.7)	1,588.3	7,077.3	(5,489.1)
PPL	12,354.7	10,667.6	1,687.0	10,574.7	10,581.9	(7.2)
PSEG	11,915.2	10,208.0	1,707.2	11,183.8	10,264.8	919.0
RECO	0.0	330.9	(330.9)	0.0	322.7	(322.7)

Demand

Demand includes physical load and exports and virtual transactions.

Peak Demand

In this section, demand refers to accounting load and exports and in the Day-Ahead Energy Market also includes virtual transactions.[30]

The PJM system real-time peak load for the first three months of 2017 was 127,543 MW in the HE 0700 on January 09, 2017, which was 2,333MW, or 1.8 percent, lower than the peak load for the first three months of 2016, which was 129,876 MW in the HE 0700 on January 19, 2016.

29 Zonal real-time generation data for the map and corresponding table is based on the zonal designation for every bus listed in the most current PJM LMP bus model, which can be found at <http://www.pjm.com/markets-and-operations/energy/lmp-model-info.aspx>.

30 PJM reports peak load including accounting load plus an addback equal to PJM's estimated load drop from demand side resources. This will generally result in PJM reporting peak load values greater than accounting load values. PJM's load drop estimate is based PJM Manual 19: Load Forecasting and Analysis Attachment A: Load Drop Estimate Guidelines at <http://www.pjm.com/~/media/documents/manuals/m19.ashx>.

Table 3-14 shows the peak loads for the first three months of 1999 through 2017.

Table 3-14 Actual PJM footprint peak loads: January through March, 1999 to 2017[31]

(Jan - Mar)	Date	Hour Ending (EPT)	PJM Load (MW)	Annual Change (MW)	Annual Change (%)
1999	Tue, January 05	19	99,982	NA	NA
2000	Thu, January 27	20	102,359	2,377	2.4%
2001	Tue, January 02	19	100,411	(1,948)	(1.9%)
2002	Mon, March 04	20	97,334	(3,077)	(3.1%)
2003	Thu, January 23	19	112,755	15,421	15.8%
2004	Mon, January 26	19	106,760	(5,995)	(5.3%)
2005	Tue, January 18	19	111,973	5,213	4.9%
2006	Mon, February 13	20	100,065	(11,908)	(10.6%)
2007	Mon, February 05	20	118,800	18,736	18.7%
2008	Thu, January 03	19	111,724	(7,076)	(6.0%)
2009	Fri, January 16	19	117,169	5,445	4.9%
2010	Mon, January 04	19	109,210	(7,959)	(6.8%)
2011	Mon, January 24	8	110,659	1,448	1.3%
2012	Tue, January 03	19	122,539	11,880	10.7%
2013	Tue, January 22	19	126,632	4,093	3.3%
2014	Tue, January 07	19	140,467	13,835	10.9%
2015	Fri, February 20	8	143,086	2,619	1.9%
2016	Tue, January 19	8	129,876	(13,210)	(9.2%)
2017	Mon, January 09	8	127,543	(2,333)	(1.8%)

Figure 3-14 shows the peak loads for the first three months of 1999 through 2017.

Figure 3-14 PJM footprint calendar year peak loads: January 1 through March 31, 1999 to 2017

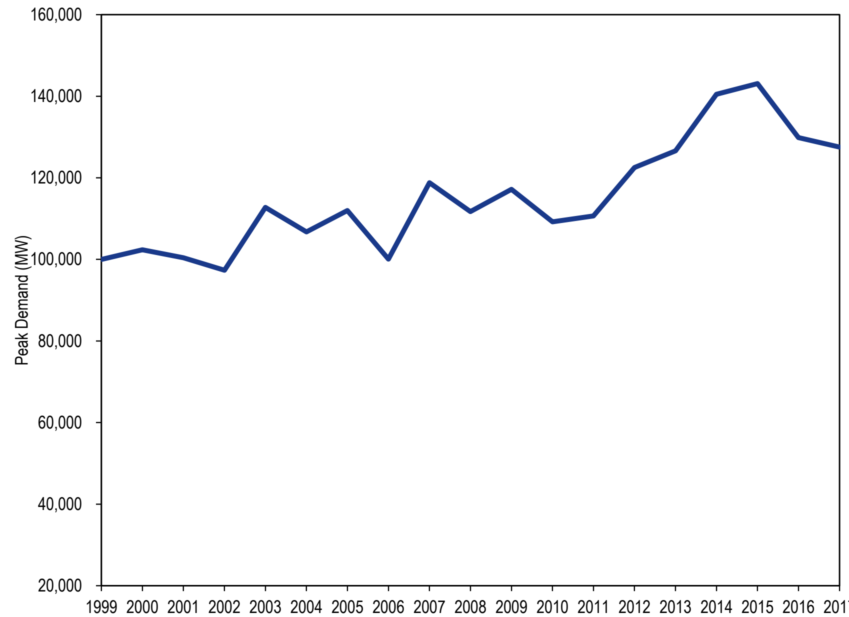
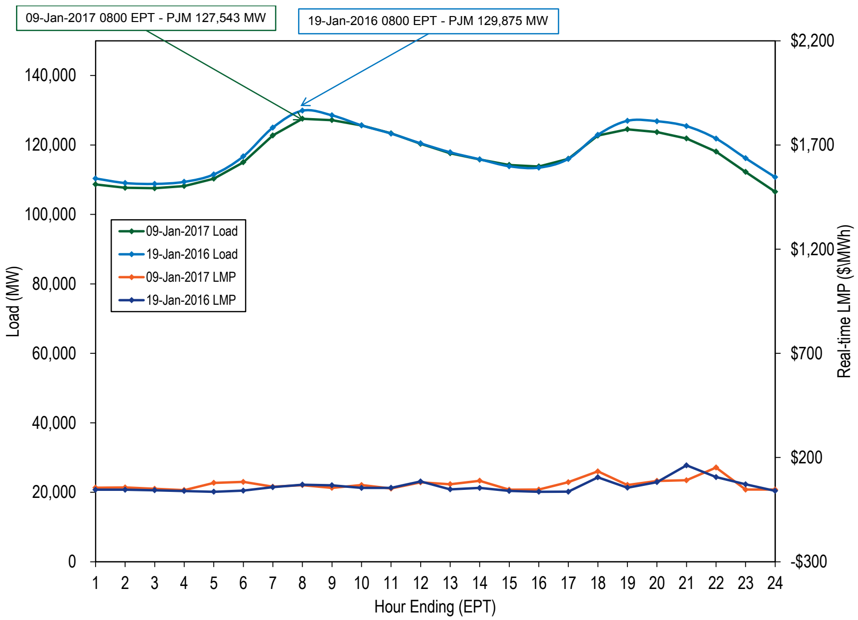


Figure 3-15 compares the peak load days during the first three months of 2016 and 2017. The highest average hourly real-time LMP on January 09, 2017 was $151.98 and on January 19, 2016 was $162.73.

31 Peak loads shown are Power accounting load. See the *MMU Technical Reference for the PJM Markets*, at "Load Definitions" for detailed definitions of load. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

Figure 3-15 PJM peak-load comparison Tuesday, January 19, 2016 and Monday, January 09, 2017



Real-Time Demand

PJM average real-time load in the first three months of 2017 decreased from the first three months of 2016, from 89,322 MW to 87,598 MW.[32]

PJM average real-time demand in the first three months of 2017 slightly increased from the first three months of 2016, from 92,777 MW to 92,791 MW.

In the PJM Real-Time Energy Market, there are two types of demand:

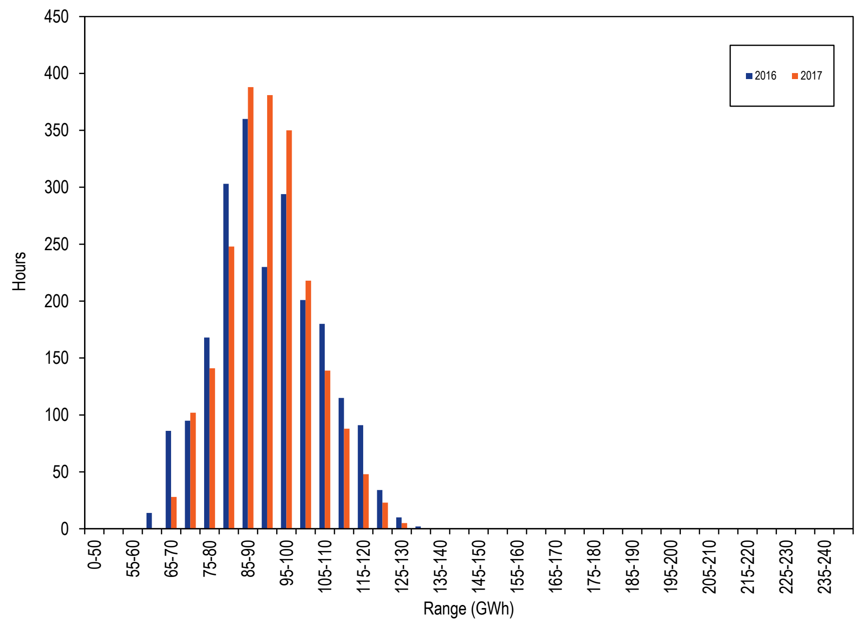
- **Load.** The actual MWh level of energy used by load within PJM.
- **Export.** An export is an external energy transaction scheduled from PJM to another balancing authority. A real-time export must have a valid OASIS reservation when offered, must have available ramp room to support the export, must be accompanied by a NERC Tag, and must pass the neighboring balancing authority checkout process.

32 Load data are the net MWh injections and withdrawals MWh at every load bus in PJM.

PJM Real-Time Demand Duration

Figure 3-16 shows the hourly distribution of PJM real-time load plus exports for the first three months of 2016 and 2017.[33]

Figure 3-16 Distribution of PJM real-time accounting load plus exports: January through March, 2016 and 2017[34]



33 All real-time load data in Section 3, "Energy Market," "Market Performance: Load and LMP," are based on PJM accounting load. See the *Technical Reference for PJM Markets*, "Load Definitions," for detailed definitions of accounting load. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.
34 Each range on the horizontal axis excludes the start value and includes the end value.

PJM Real-Time, Average Load

Table 3-15 presents summary real-time demand statistics for the first three months of 1998 to 2017. Before June 1, 2007, transmission losses were included in accounting load. After June 1, 2007, transmission losses were excluded from accounting load and losses were addressed through marginal loss pricing.[35]

Table 3-15 PJM real-time average hourly load and real-time average hourly load plus average hourly exports: January 1 through March 31, 1998 through 2017[36]

	PJM Real-Time Demand (MWh)				Year-to-Year Change			
	Load		Load Plus Exports		Load		Load Plus Exports	
Jan-Mar	Load	Standard Deviation	Demand	Standard Deviation	Load	Standard Deviation	Demand	Standard Deviation
1998	28,019	3,762	28,019	3,762	NA	NA	NA	NA
1999	29,784	4,027	29,784	4,027	6.3%	7.0%	6.3%	7.0%
2000	30,367	4,624	30,367	4,624	2.0%	14.8%	2.0%	14.8%
2001	31,254	3,846	33,452	3,704	2.9%	(16.8%)	10.2%	(19.9%)
2002	29,968	4,083	30,988	3,932	(4.1%)	6.1%	(7.4%)	6.1%
2003	39,249	5,546	41,600	5,701	31.0%	35.8%	34.2%	45.0%
2004	39,549	5,761	41,198	5,394	0.8%	3.9%	(1.0%)	(5.4%)
2005	71,388	8,966	79,319	9,587	80.5%	55.6%	92.5%	77.8%
2006	80,179	8,977	86,567	9,378	12.3%	0.1%	9.1%	(2.2%)
2007	84,586	12,040	90,304	12,012	5.5%	34.1%	4.3%	28.1%
2008	82,235	10,184	89,092	10,621	(2.8%)	(15.4%)	(1.3%)	(11.6%)
2009	81,170	11,718	86,110	11,948	(1.3%)	15.1%	(3.3%)	12.5%
2010	81,121	10,694	86,843	11,262	(0.1%)	(8.7%)	0.9%	(5.7%)
2011	81,018	10,273	86,635	10,613	(0.1%)	(3.9%)	(0.2%)	(5.8%)
2012	86,329	10,951	91,090	11,293	6.6%	6.6%	5.1%	6.4%
2013	91,337	10,610	95,835	10,452	5.8%	(3.1%)	5.2%	(7.4%)
2014	98,317	13,484	104,454	12,843	7.6%	27.1%	9.0%	22.9%
2015	97,936	13,445	102,821	13,855	(0.4%)	(0.3%)	(1.6%)	7.9%
2016	89,322	13,262	92,777	13,409	(8.8%)	(1.4%)	(9.8%)	(3.2%)
2017	87,598	11,208	92,791	11,295	(1.9%)	(15.5%)	0.0%	(15.8%)

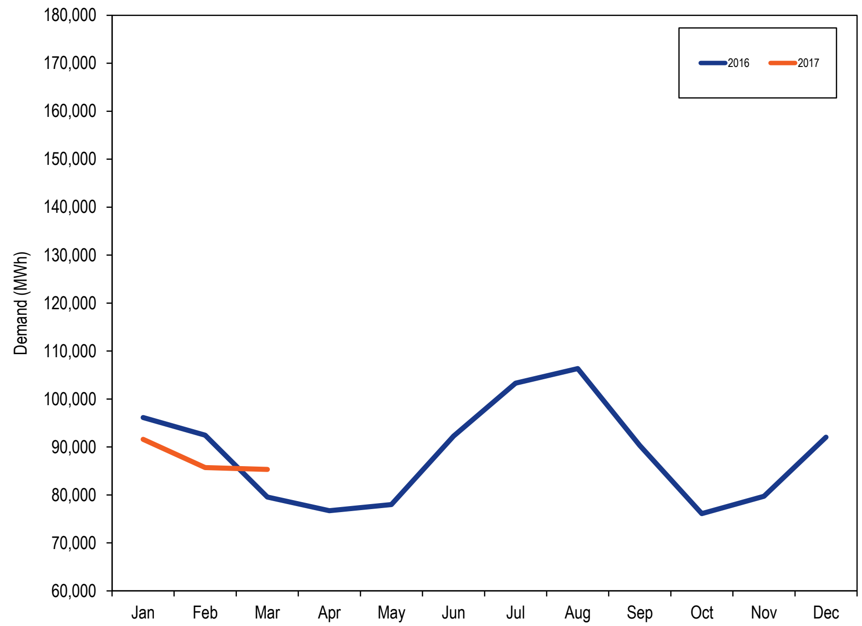
35 Accounting load is used here because PJM uses accounting load in the settlement process, which determines how much load customers pay for. In addition, the use of accounting load with losses before June 1, and without losses after June 1, 2007, is consistent with PJM's calculation of LMP, which excluded losses prior to June 1 and includes losses after June 1.

36 Export data are not available before June 1, 2000. The export data for 2000 are for the last six months of 2000.

PJM Real-Time, Monthly Average Load

Figure 3-17 compares the real-time, monthly average hourly loads for 2016 and the first three months of 2017.

Figure 3-17 PJM real-time monthly average hourly load: January 1, 2016 through March 31, 2107



PJM real-time load is significantly affected by temperature. Figure 3-18 and Table 3-16 compare the PJM monthly heating and cooling degree days in 2016 and the first three months of 2017.[37] Heating degree days decreased 10.6 percent from the first three months of 2016 to 2017.

37 A heating degree day is defined as the number of degrees that a day's average temperature is below 65 degrees F (the temperature below which buildings need to be heated). A cooling degree day is the number of degrees that a day's average temperature is above 65 degrees F (the temperature when people will start to use air conditioning to cool buildings). PJM uses 60 degrees F for a heating degree day as stated in Manual 19.
Heating and cooling degree days are calculated by weighting the temperature at each weather station in the individual transmission zones using weights provided by PJM in Manual 19. Then the temperature is weighted by the real-time zonal accounting load for each transmission zone. After calculating an average hourly temperature across PJM, the heating and cooling degree formulas are used to calculate the daily heating and cooling degree days, which are summed for monthly reporting. The weather stations that provided the

Figure 3-18 PJM heating and cooling degree days: January 1, 2016 through March 31, 2017

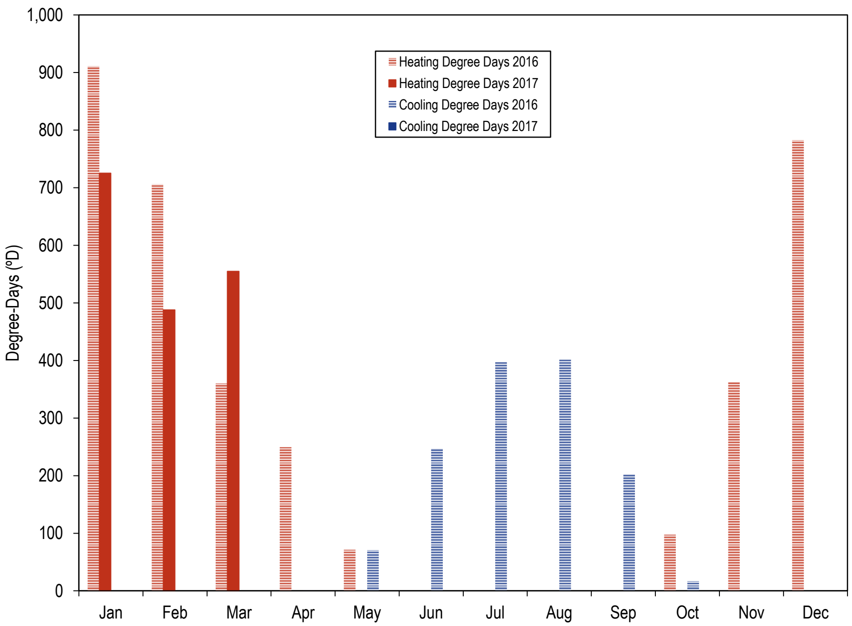


Table 3-16 PJM heating and cooling degree days: 2016 and January through March, 2017

	2016		2017		Percent Change	
	Heating Degree Days	Cooling Degree Days	Heating Degree Days	Cooling Degree Days	Heating Degree Days	Cooling Degree Days
Jan	911	0	725	0	(20.4%)	0.0%
Feb	706	0	488	0	(30.9%)	0.0%
Mar	360	0	555	0	54.1%	0.0%
Apr	250	1				
May	71	71				
Jun	0	247				
Jul	0	397				
Aug	0	402				
Sep	0	203				
Oct	98	17				
Nov	363	0				
Dec	782	0				
Total	3,541	1,337	1,768	0	(23.1%)	
Jan-Mar	1,977	0	1,768	0	(10.6%)	0.0%

Day-Ahead Demand

PJM average day-ahead demand in the first three months of 2017, including DECs and up to congestion transactions, increased by 3.9 percent from the first three months of 2016, from 130,534 MW to 135,560 MW.

PJM average day-ahead demand in the first three months of 2017, including DECs, up to congestion transactions, and exports, increased by 4.6 percent from the first three months of 2016, from 133,386 MW to 139,467 MW.

The reduction in up to congestion transactions (UTC) that had followed a FERC order setting September 8, 2014, as the effective date for any uplift charges subsequently assigned to UTCs, was reversed. There was an increase in up to congestion volume as a result of the expiration of the 15 month refund period for the proceeding related to uplift charges for UTC transactions.[38]

In the PJM Day-Ahead Energy Market, five types of financially binding demand bids are made and cleared:

basis for the analysis are ABE, ACY, AVP, BWI, CAK, CLE, CMH, CRW, CVG, DAY, DCA, ERI, EWR, FWA, IAD, ILG, IPT, LEX, ORD, ORF, PHL, PIT, RIC, ROA, TOL and WAL.

38 148 FERC ¶ 61,144 (2014).

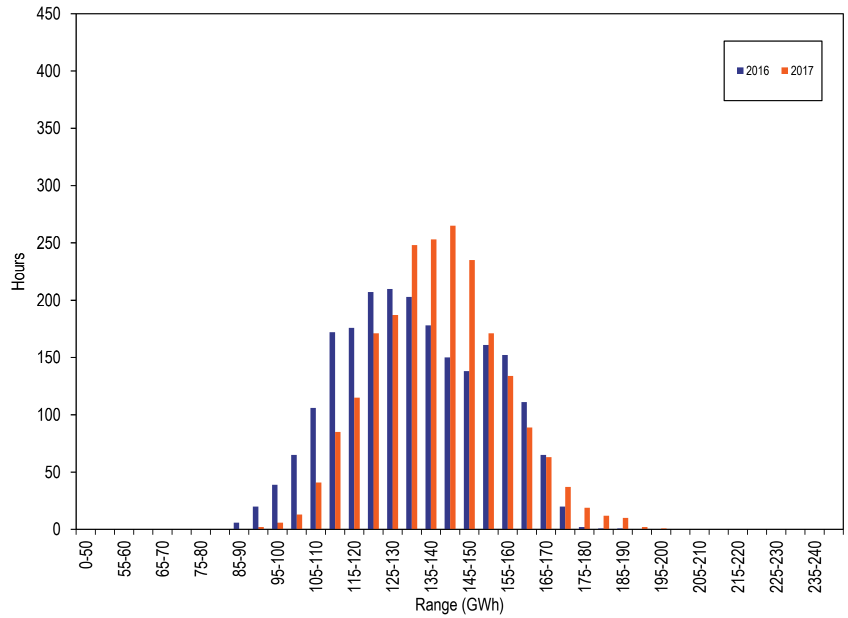
- **Fixed-Demand Bid.** Bid to purchase a defined MWh level of energy, regardless of LMP.
- **Price-Sensitive Bid.** Bid to purchase a defined MWh level of energy only up to a specified LMP, above which the load bid is zero.
- **Decrement Bid (DEC).** Financial bid to purchase a defined MWh level of energy up to a specified LMP, above which the bid is zero. A DEC can be submitted by any market participant.
- **Up to Congestion Transaction (UTC).** A conditional transaction that permits a market participant to specify a maximum price spread between the transaction source and sink. An up to congestion transaction is evaluated as a matched pair of an injection and a withdrawal analogous to a matched pair of an INC offer and a DEC bid.
- **Export.** An external energy transaction scheduled from PJM to another balancing authority. An export must have a valid willing to pay congestion (WPC) OASIS reservation when offered. An export energy transaction that clears the Day-Ahead Energy Market is financially binding. There is no link between transactions submitted in the PJM Day-Ahead Energy Market and the PJM Real-Time Energy Market, so an export energy transaction approved in the Day-Ahead Energy Market will not physically flow in real time unless it is also submitted through the Real-Time Energy Market scheduling process.

PJM day-ahead demand is the hourly total of the five types of cleared demand bids.

PJM Day-Ahead Demand Duration

Figure 3-19 shows the hourly distribution of PJM day-ahead demand, including decrement bids, up to congestion transactions, and exports for the first three months of 2016 and 2017.

Figure 3-19 Distribution of PJM day-ahead demand plus exports: January 1 through March 31, 2016 and 2017[39]



39 Each range on the horizontal axis excludes the start value and includes the end value.

PJM Day-Ahead, Average Demand

Table 3-17 presents summary day-ahead demand statistics for the first three months of each year from 2000 to 2017.[40]

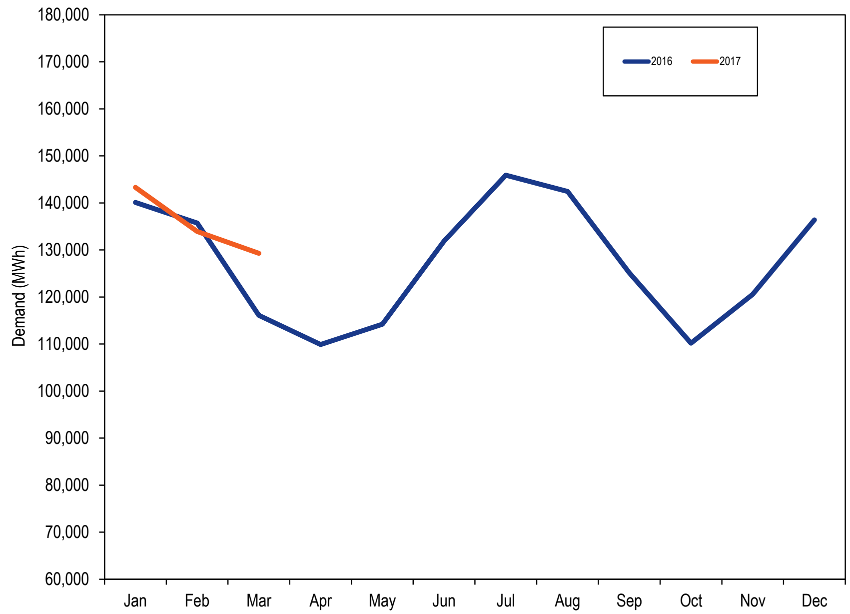
Table 3-17 PJM day-ahead average demand and day-ahead average hourly demand plus average hourly exports: January 1 through March 31, 2000 through 2017

	PJM Day-Ahead Demand (MWh)				Year-to-Year Change			
	Demand		Demand Plus Exports		Demand		Demand Plus Exports	
Jan-Mar	Demand	Standard Deviation	Demand	Standard Deviation	Demand	Standard Deviation	Demand	Standard Deviation
2000	NA	NA	NA	NA	NA	NA	NA	NA
2001	33,731	4,557	34,523	4,390	NA	NA	NA	NA
2002	33,976	4,960	34,004	4,964	0.7%	8.9%	(1.5%)	13.1%
2003	47,034	6,841	47,147	6,853	38.4%	37.9%	38.7%	38.1%
2004	46,885	5,591	47,123	5,537	(0.3%)	(18.3%)	(0.1%)	(19.2%)
2005	87,341	9,810	90,288	9,947	86.3%	75.5%	91.6%	79.7%
2006	96,244	9,453	99,342	9,777	10.2%	(3.6%)	10.0%	(1.7%)
2007	108,699	12,601	111,831	12,746	12.9%	33.3%	12.6%	30.4%
2008	105,995	10,677	109,428	10,975	(2.5%)	(15.3%)	(2.1%)	(13.9%)
2009	102,366	13,619	105,023	13,758	(3.4%)	27.5%	(4.0%)	25.4%
2010	101,012	11,937	104,866	12,103	(1.3%)	(12.4%)	(0.1%)	(12.0%)
2011	107,116	11,890	110,865	12,157	6.0%	(0.4%)	5.7%	0.4%
2012	129,258	13,163	132,757	13,481	20.7%	10.7%	19.7%	10.9%
2013	143,585	13,120	146,878	13,108	11.1%	(0.3%)	10.6%	(2.8%)
2014	163,031	11,914	167,318	11,717	13.5%	(9.2%)	13.9%	(10.6%)
2015	119,078	14,226	123,282	14,565	(27.0%)	19.4%	(26.3%)	24.3%
2016	130,534	18,683	133,386	18,860	9.6%	31.3%	8.2%	29.5%
2017	135,560	16,273	139,467	16,462	3.9%	(12.9%)	4.6%	(12.7%)

PJM Day-Ahead, Monthly Average Demand

Figure 3-20 compares the day-ahead, monthly average hourly demand, including decrement bids and up to congestion transactions in 2016 and the first three months of 2017

Figure 3-20 PJM day-ahead monthly average hourly demand: January 1, 2016 through March 31, 2017



Real-Time and Day-Ahead Demand

Table 3-18 presents summary statistics for the first three months of 2016 and 2017 day-ahead and real-time demand. All data are cleared MW. The last two columns of Table 3-18 are the day-ahead demand minus the real-time demand. The first such column is the total day-ahead demand less the total real-time demand and the second such column is the total physical day-ahead load (fixed demand plus price-sensitive demand) less the physical real-time load.

40 Since the Day-Ahead Energy Market did not start until June 1, 2000, the day-ahead data for 2000 only includes data for the last six months of that year.

Table 3-18 Cleared day-ahead and real-time demand (MWh): January 1 through March 31, 2016 and 2017

		Day-Ahead						Real-Time		Day-Ahead Less Real-Time	
	Year	Fixed Demand	Price Sensitive	DEC Bids	Up-to Congestion	Exports	Total Demand	Load	Total Demand	Total Demand	Total Load
Average	2016	86,525	3,221	4,075	36,705	2,852	133,386	89,322	92,777	40,608	48,714
	2017	85,432	2,743	4,869	42,516	3,907	139,467	87,598	92,791	46,676	40,923
Median	2016	85,443	3,208	3,735	36,131	2,762	132,475	87,962	91,595	40,880	47,082
	2017	85,446	2,742	4,678	42,702	3,855	139,254	87,106	92,183	47,071	40,035
Standard Deviation	2016	12,090	396	1,305	7,490	608	18,860	13,262	13,409	5,452	7,810
	2017	10,669	308	1,179	7,515	863	16,462	11,208	11,295	5,167	6,041
Peak Average	2016	92,978	3,428	4,315	38,741	2,851	142,351	95,708	99,063	43,288	52,420
	2017	91,430	2,938	5,109	45,126	3,986	148,589	93,329	98,584	50,004	43,325
Peak Median	2016	92,889	3,404	4,166	37,989	2,785	142,530	95,338	98,602	43,928	51,410
	2017	90,895	2,973	4,904	44,873	3,981	147,313	92,487	97,826	49,487	43,000
Peak Standard Deviation	2016	9,791	323	1,157	7,506	571	16,338	11,312	11,683	4,655	6,657
	2017	7,701	252	1,045	6,733	843	12,754	8,562	8,743	4,011	4,551
Off-Peak Average	2016	80,653	3,031	3,856	34,852	2,853	125,228	83,511	87,058	38,170	45,341
	2017	79,858	2,562	4,647	40,090	3,833	130,989	82,272	87,407	43,582	38,690
Off-Peak Median	2016	79,956	2,984	3,417	34,172	2,745	123,918	82,392	85,932	37,985	44,407
	2017	79,081	2,548	4,385	40,154	3,739	129,778	81,321	86,473	43,305	38,017
Off-Peak Standard Deviation	2016	10,937	360	1,392	6,980	640	17,234	12,194	12,272	4,961	7,233
	2017	10,002	238	1,251	7,392	876	14,919	10,743	10,724	4,196	6,547

Figure 3-21 shows the average hourly cleared volumes of day-ahead demand and real-time demand for the first three months of 2017. The day-ahead demand includes day-ahead load, day-ahead exports, decrement bids and up to congestion transactions. The real-time demand includes real-time load and real-time exports.

Figure 3-21 Day-ahead and real-time demand (Average hourly volumes): January 1 through March 31, 2017

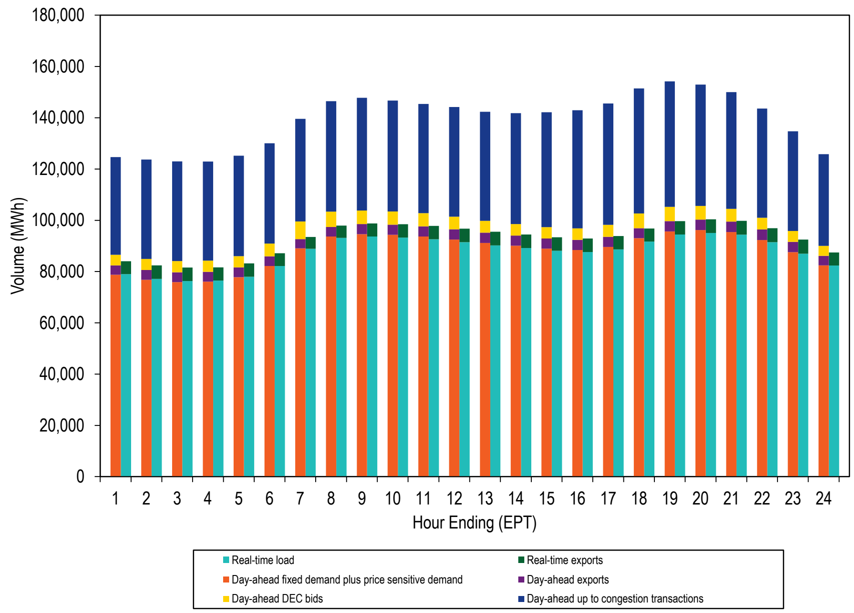


Figure 3-22 Difference between day-ahead and real-time demand (Average daily volumes): January 1, 2016 through March 31, 2017

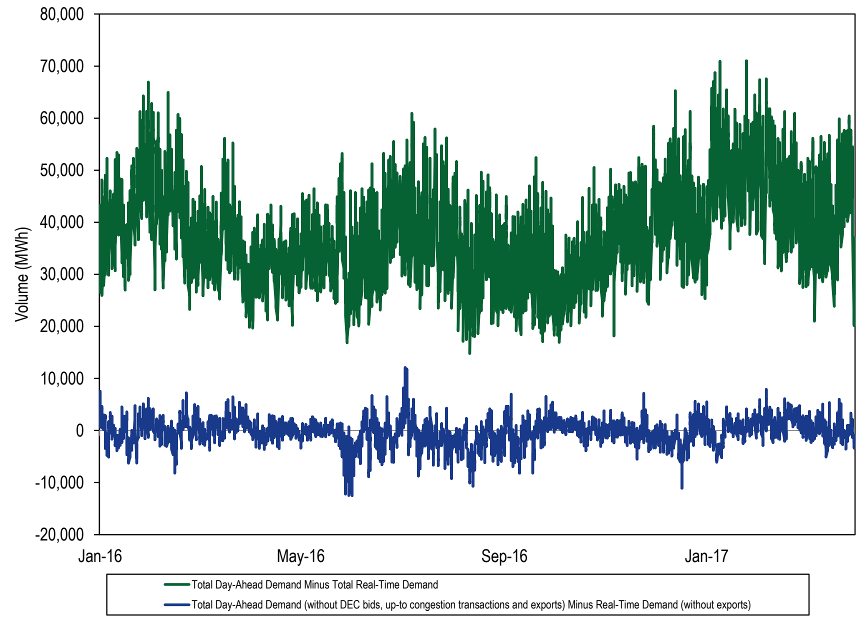


Figure 3-22 shows the difference between the day-ahead and real-time average daily demand from January 2016 through March 2017. There was an increase in up to congestion volume as a result of the expiration of the fifteen month potential refund period for the proceeding related to uplift charges for UTC transactions on December 7, 2015.

Supply and Demand: Load and Spot Market

Real-Time Load and Spot Market

Participants in the PJM Real-Time Energy Market can use their own generation to meet load, to sell in the bilateral market or to sell in the spot market in any hour. Participants can both buy and sell via bilateral contracts and buy and sell in the spot market in any hour. If a participant has positive net bilateral transactions in an hour, it is buying energy through bilateral contracts (bilateral purchase). If a participant has negative net bilateral transactions in an hour, it is selling energy through bilateral contracts (bilateral sale). If a participant has positive net spot transactions in an hour, it is buying energy from the spot market (spot purchase). If a participant has negative net spot transactions in an hour, it is selling energy to the spot market (spot sale).

Real-time load is served by a combination of self-supply, bilateral market purchases and spot market purchases. From the perspective of a parent company of a PJM billing organization that serves load, its load could be supplied by any combination of its own generation, net bilateral market purchases and net spot market purchases. In addition to directly serving load, load serving entities can also transfer their responsibility to serve load to other parties through eSchedules transactions referred to as wholesale load responsibility (WLR) or retail load responsibility (RLR) transactions. When the responsibility to serve load is transferred via a bilateral contract, the entity to which the responsibility is transferred becomes the load serving entity. Supply from its own generation (self-supply) means that the parent company is generating power from plants that it owns in order to meet demand. Supply from bilateral purchases means that the parent company is purchasing power under bilateral contracts from a nonaffiliated company at the same time that it is meeting load. Supply from spot market purchases means that the parent company is generating less power from owned plants and/or purchasing less power under bilateral contracts than required to meet load at a defined time and, therefore, is purchasing the required balance from the spot market.

The PJM system's reliance on self-supply, bilateral contracts and spot purchases to meet real-time load is calculated by summing across all the parent companies of PJM billing organizations that serve load in the Real-Time Energy Market for each hour. Table 3-19 shows the monthly average share of real-time load served by self-supply, bilateral contracts and spot purchase in 2016 and through March 2017 based on parent company. In the first three months of 2017, 17.9 percent of real-time load was supplied by bilateral contracts, 20.9 percent by spot market purchase and 61.1 percent by self-supply. Compared with the first three months of 2016, reliance on bilateral contracts increased by 5.1 percentage points, reliance on spot supply decreased by 3.0 percentage points and reliance on self-supply increased by 2.1 percentage points.

Table 3-19 Monthly average percent of real-time self-supply load, bilateral-supply load and spot-supply load based on parent companies: January 1, 2016 through March 31, 2017[41]

	2016			2017			Difference in Percentage Points		
	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply
Jan	11.1%	25.9%	63.0%	18.2%	20.3%	61.5%	7.1%	(5.7%)	(1.5%)
Feb	11.5%	25.5%	63.0%	19.4%	19.9%	60.7%	8.0%	(5.6%)	(2.3%)
Mar	11.7%	26.4%	61.9%	16.2%	22.6%	61.1%	4.5%	(3.8%)	(0.8%)
Apr	12.7%	24.0%	63.4%						
May	12.6%	24.5%	62.9%						
Jun	12.5%	24.2%	63.2%						
Jul	12.8%	23.3%	63.9%						
Aug	12.7%	23.6%	63.7%						
Sep	12.4%	22.7%	64.9%						
Oct	14.6%	21.4%	64.0%						
Nov	14.3%	23.2%	62.4%						
Dec	15.6%	22.3%	62.1%						
Annual	12.9%	23.9%	63.2%	17.9%	20.9%	61.1%	5.1%	(3.0%)	(2.1%)

Day-Ahead Load and Spot Market

In the PJM Day-Ahead Energy Market, participants can not only use their own generation, bilateral contracts and spot market purchases to supply their load serving obligation, but can also use virtual resources to meet their load serving obligations in any hour. Virtual supply is treated as supply in the day-ahead analysis and virtual demand is treated as demand in the day-ahead analysis.

The PJM system's reliance on self-supply, bilateral contracts, and spot purchases to meet day-ahead demand (cleared fixed-demand, price-sensitive load and decrement bids) is calculated by summing across all the parent companies of PJM billing organizations that serve demand in the Day-Ahead Energy Market for each hour. Table 3-20 shows the monthly average share of day-ahead demand served by self-supply, bilateral contracts and spot purchases in 2016 through March 2017, based on parent companies. In the first three months of 2017, 10.5 percent of day-ahead demand was supplied by bilateral contracts, 21.1 percent by spot market purchases, and 68.4 percent

41 Table 3-19 and Table 3-20 were calculated as of April 20, 2017. The values may change slightly as billing values are updated by PJM.

by self-supply. Compared with the first three months of 2016, reliance on bilateral contracts increased by 1.6 percentage points, reliance on spot supply decreased by 2.3 percentage points, and reliance on self-supply increased by 0.8 percentage points.

Table 3-20 Monthly average share of day-ahead self-supply demand, bilateral supply demand, and spot-supply demand based on parent companies: January 1, 2016 through March 31, 2017

	2016			2017			Difference in Percentage Points		
	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply
Jan	8.2%	25.9%	65.9%	11.0%	20.6%	68.4%	2.8%	(5.3%)	2.5%
Feb	8.5%	25.5%	66.0%	11.2%	20.6%	68.2%	2.7%	(4.9%)	2.2%
Mar	8.0%	27.0%	65.0%	9.2%	22.4%	68.4%	1.2%	(4.6%)	3.4%
Apr	9.9%	24.3%	65.8%						
May	9.6%	24.4%	66.0%						
Jun	8.3%	22.3%	69.4%						
Jul	8.7%	22.8%	68.6%						
Aug	8.5%	22.7%	68.8%						
Sep	7.9%	22.7%	69.4%						
Oct	9.5%	21.3%	69.2%						
Nov	9.4%	22.3%	68.2%						
Dec	10.4%	21.4%	68.2%						
Annual	8.9%	23.5%	67.6%	10.5%	21.2%	68.4%	1.6%	(2.3%)	0.8%

Market Behavior

Offer Capping for Local Market Power

In the PJM Energy Market, offer capping occurs as a result of structurally noncompetitive local markets and noncompetitive offers in the Day-Ahead and Real-Time Energy Markets. PJM also uses offer capping for units that are committed for reliability reasons, specifically for providing black start and reactive service as well as for conservative operations. There are no explicit rules governing market structure or the exercise of market power in the aggregate energy market. PJM's market power mitigation goals have focused on market designs that promote competition and that limit local market power mitigation to situations where the local market structure is not competitive and thus where market design alone cannot mitigate 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 offer cap owners when the local market structure is noncompetitive. However, there are some issues with the application of mitigation in the Day-Ahead Energy Market and the Real-Time Energy Market when market sellers fail the TPS test. There is no tariff or manual language that defines in detail the application of the TPS test and offer capping in the Day-Ahead Energy Market and the Real-Time Energy Market.

In both the Day-Ahead and Real-Time Energy Markets, generators have the ability to avoid mitigation by using varying markups in their price-based offers, offering different operating parameters in their price-based and cost-based offers, and using different fuels in their price-based and cost-based offers. These issues can be resolved by simple rule changes.

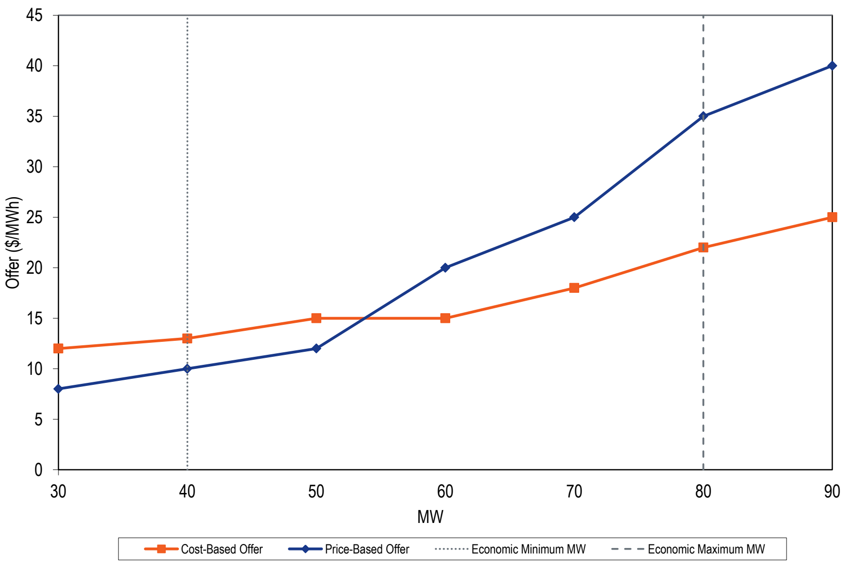
When an owner fails the TPS test, the units offered by the owner that are committed to provide relief are committed on the cheaper of cost or price-based offers. PJM uses a dispatch cost formula to compare price-based offers and cost-based offers to select the cheaper offer.[42] Dispatch cost is calculated as:

((Incremental Energy Offer @ EcoMin*EcoMin MW) + No-Load Cost)*Min Run Time + Startup Cost.

With the ability to submit offer curves with varying markups at different output levels in the price-based offer, units can avoid mitigation by using a low markup at low output levels and a high markup at higher output levels. Figure 3-23 shows an example of offers from a unit that has a negative markup at the economic minimum MW level and a positive markup at the economic maximum MW level. The result would be that a unit that failed the TPS test would be committed on its price-based offer that has a lower dispatch cost, even though the price-based offer is higher than cost-based offer at higher output levels and includes positive markups, inconsistent with the explicit goal of local market power mitigation.

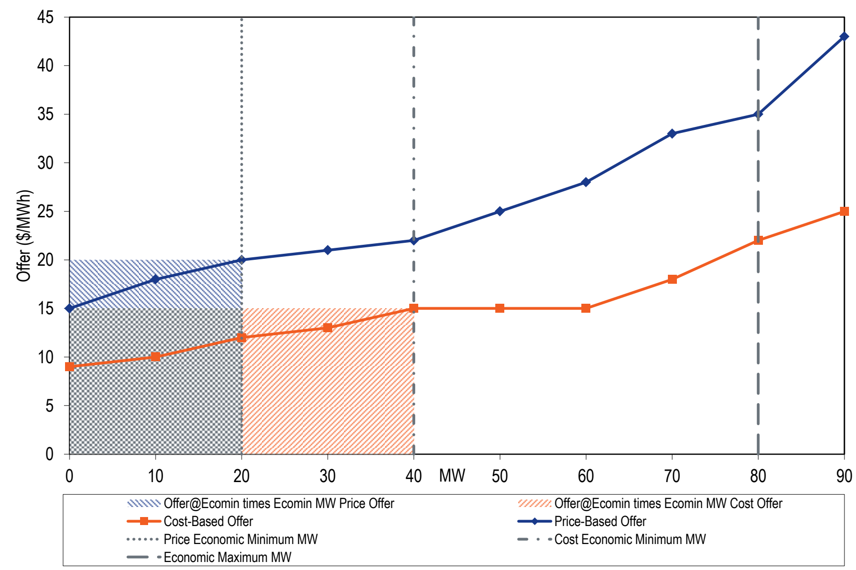
42 See, PJM OA Schedule 1 § 6.4.1 (g).

Figure 3-23 Offers with varying markups at different MW output levels



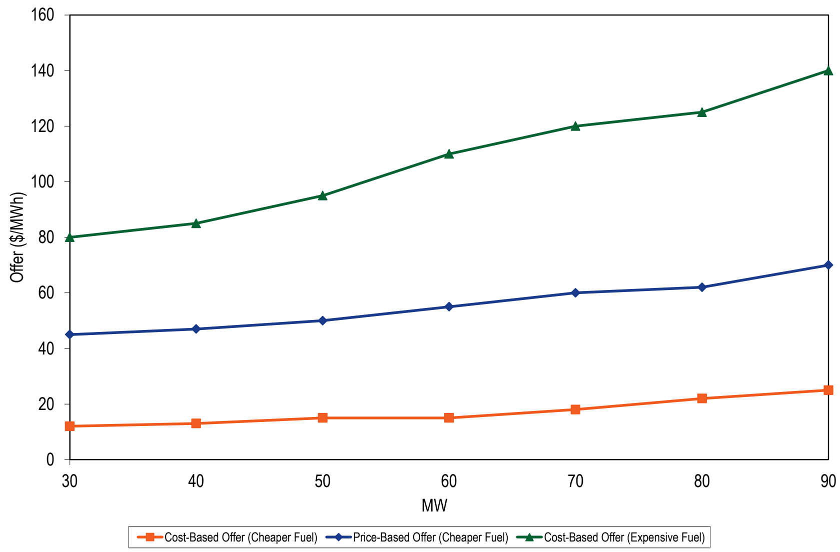
Offering a different economic minimum MW level, different minimum run times, different start up and notification times on the cost-based and price-based offers can also be used to avoid mitigation. For example, a unit may offer its price-based offer with a positive markup, but have a shorter minimum run time (MRT) on the price-based offer resulting in a lower dispatch cost for the price based offer but setting prices at a level that includes a positive markup. For example, a unit may offer a lower economic minimum MW level on the price-based offer than the cost-based offer. Such a unit may appear to be cheaper to commit on the price-based offer even with a positive markup. A unit with a positive markup can have lower dispatch cost on price-based offer because of a lower economic minimum level compared to cost-based offer. Figure 3-24 shows an example of offers from a unit that has a positive markup and a price-based offer with a lower economic minimum MW than the cost-based offer. Keeping the startup cost, Minimum Run Time and No-load cost constant between the price-based offer and cost-based offer, the dispatch cost for this unit is lower on the price-based offer than on the cost-based offer. However, the price-based offer includes a positive markup and could result in setting the market price at a noncompetitive level even after the resource owner fails the TPS test.

Figure 3-24 Offers with a positive markup but different economic minimum MW



In case of dual fuel units, if the price-based offer uses a cheaper fuel and the cost-based offer uses a more expensive fuel, the price-based offer will appear to be lower cost even when it includes a markup. Figure 3-25 shows an example of offers by a dual fuel unit, where the active cost-based offer uses a more expensive fuel and the price-based offer uses a cheaper fuel and includes a markup.

Figure 3-25 Dual fuel unit offers



These issues can be solved by simple rule changes.[43] The MMU recommends that markup of price based offers over cost-based offers be constant across the offer curve, that there be at least one cost-based offer using the same fuel as the available price-based offer, and that operating parameters on parameter limited schedules (PLS) be at least as flexible as price-based non-PLS offers.

Levels of offer capping have historically been low in PJM, as shown in Table 3-21. The offer capping percentages shown in Table 3-21 include units that are committed to provide constraint relief whose owners failed the TPS test in the energy market as well as units committed as part of conservative operations, excluding units that were committed for providing black start and reactive service.

Table 3-21 Offer capping statistics – energy only: January 1 through March 31, 2013 to 2017

	Real-Time		Day-Ahead	
(Jan-Mar)	Unit Hours Capped	MW Capped	Unit Hours Capped	MW Capped
2013	0.3%	0.1%	0.1%	0.0%
2014	1.1%	0.4%	0.3%	0.2%
2015	0.6%	0.2%	0.3%	0.1%
2016	0.4%	0.2%	0.1%	0.1%
2017	0.2%	0.1%	0.0%	0.0%

Table 3-22 shows the offer capping percentages including units committed to provide constraint relief and units committed to provide black start service and reactive support. The units that are committed and offer capped for black start service and reactive support reasons increased from 2012 through 2013. Before 2011, the units that ran to provide black start service and reactive support were generally economic in the energy market. From 2011 through 2013, the percentage of hours when these units were not economic (and were therefore committed on their cost schedule for reliability reasons) increased. This trend reversed in 2014, 2015 and 2016 because higher LMPs (in the first six months) resulted in the increased economic dispatch of black start and reactive service resources. As of April 2015, the Automatic Load Rejection (ALR) units that were committed for black start previously no longer provide black start service, and are not included in the offer capping statistics for black start. PJM also created closed loop interfaces to, in some cases, model reactive constraints. The result was higher LMPs, which increased economic dispatch, which contributed to the reduction in units offer capped for reactive support. In instances where units are now committed for the modeled closed loop interface constraints, they are considered offer capped for providing constraint relief. They are included in the offer capping percentages in Table 3-21.

43 The MMU proposed these offer rule changes as part of a broader reform to address generator offer flexibility and associated impact on market power mitigation rules in the Generator Offer Flexibility Senior Task Force (GOFSTF) and subsequently in the MMU's protest in the hourly offers proceeding in Docket No. ER16-372-000, filed December 14, 2015.

Table 3-22 Offer capping statistics for energy and reliability: January 1 through March 31, 2013 to 2017

	Real-Time		Day-Ahead	
(Jan-Mar)	Unit Hours Capped	MW Capped	Unit Hours Capped	MW Capped
2013	2.7%	1.9%	3.1%	1.8%
2014	1.5%	0.9%	0.8%	0.6%
2015	0.8%	0.4%	0.5%	0.3%
2016	0.5%	0.3%	0.2%	0.1%
2017	0.4%	0.7%	0.3%	0.6%

Table 3-23 shows the offer capping percentages for units committed to provide black start service and reactive support. The data in Table 3-23 is the difference between the offer cap percentages shown in Table 3-22 and Table 3-21.

Table 3-23 Offer capping statistics for reliability: January 1 through March 31, 2013 to 2017

	Real-Time		Day-Ahead	
(Jan-Mar)	Unit Hours Capped	MW Capped	Unit Hours Capped	MW Capped
2013	2.4%	1.8%	3.0%	1.8%
2014	0.4%	0.5%	0.5%	0.4%
2015	0.3%	0.2%	0.3%	0.2%
2016	0.1%	0.1%	0.1%	0.1%
2017	0.2%	0.6%	0.2%	0.5%

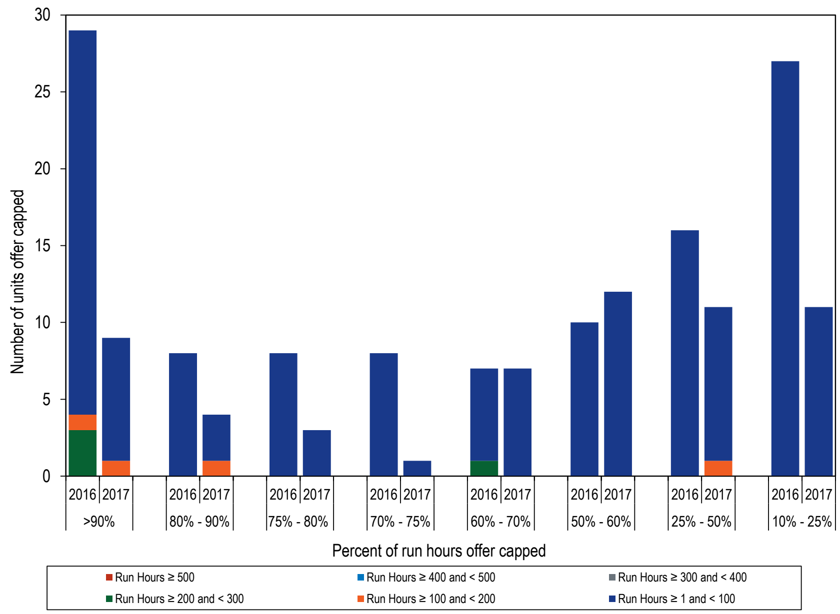
Table 3-24 presents data on the frequency with which units were offer capped in the first three months of 2016 and 2017 for failing the TPS test to provide energy for constraint relief in the Real-Time Energy Market. Table 3-24 shows that 29 units were offer capped for 90 percent or more of their run hours in the first three months of 2017 compared to nine in the first three months of 2016.

Table 3-24 Real-time offer capped unit statistics: January 1 through March 31, 2016 and 2017

		Offer-Capped Hours					
Run Hours Offer-Capped, Percent Greater Than Or Equal To:	Jan - Mar	Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
90%	2016	0	0	0	3	1	25
	2017	0	0	0	0	1	8
80% and < 90%	2016	0	0	0	0	0	8
	2017	0	0	0	0	1	3
75% and < 80%	2016	0	0	0	0	0	8
	2017	0	0	0	0	0	3
70% and < 75%	2016	0	0	0	0	0	8
	2017	0	0	0	0	0	1
60% and < 70%	2016	0	0	0	1	0	6
	2017	0	0	0	0	0	7
50% and < 60%	2016	0	0	0	0	0	10
	2017	0	0	0	0	0	12
25% and < 50%	2016	0	0	0	0	0	16
	2017	0	0	0	0	1	10
10% and < 25%	2016	0	0	0	0	0	27
	2017	0	0	0	0	0	11

Figure 3-26 shows the frequency with which units were offer capped in the first three months of 2016 and 2017 for failing the TPS test to provide energy for constraint relief in the Real-Time Energy Market.

Figure 3-26 Real-time offer capped unit statistics: January 1 through March 31, 2016 and 2017



TPS Test Statistics

In the first three months of 2017, the AEP, ATSI, BGE, ComEd, Dominion, DPL, PECO, PENELEC, and PPL control zones experienced congestion resulting from one or more constraints binding for 25 or more hours or resulting from an interface constraint (Table 3-25). The AECO, AP, DAY, DEOK, DLCO, EKPC, JCPL, Met-Ed, Pepco, PSEG and RECO control zones did not have constraints binding for 25 or more hours in the first three months of 2017. Table 3-25 shows that AEP and ComEd were the control zones that experienced congestion resulting from one or more constraints binding for 25 or more hours or resulting from an interface constraint that was binding for one or more hours in the first three months of every year from 2009 through 2017.

Table 3-25 Numbers of hours when control zones experienced congestion resulting from one or more constraints binding for 25 or more hours or from an interface constraint: January 1 through March 31, 2009 through 2017

	(Jan - Mar)								
	2009	2010	2011	2012	2013	2014	2015	2016	2017
AECO	149	0	70	40	32	0	41	252	0
AEP	890	157	556	100	447	840	1,405	283	54
AP	125	165	89	56	38	309	417	72	0
ATSI	101	37	0	1	46	428	391	30	349
BGE	0	25	0	650	150	29	232	1,418	551
ComEd	325	816	123	525	973	1,233	651	1,426	766
DEOK	0	0	0	33	0	68	0	0	0
DLCO	0	141	0	146	0	211	674	0	0
Dominion	130	114	73	0	0	52	423	458	52
DPL	43	0	28	133	0	297	388	694	389
JCPL	0	0	0	0	0	44	79	0	0
Met-Ed	0	0	0	0	0	34	144	0	0
PECO	30	0	158	0	77	327	242	287	537
PENELEC	0	0	58	32	29	179	517	237	578
Pepco	0	0	44	66	71	39	0	0	0
PPL	0	0	52	0	167	41	0	0	166
PSEG	336	344	281	199	1,408	1,445	2,550	55	0

The local market structure in the Real-Time Energy Market associated with each of the frequently binding constraints was analyzed using the three pivotal supplier results in the first three months of 2017.[44] The three pivotal supplier (TPS) test is applied every time the system solution indicates that out of merit resources are needed to relieve a transmission constraint. Only uncommitted resources, which would be started to relieve the transmission constraint, are subject to offer capping. Already committed units that can provide incremental relief cannot be offer capped. The results of the TPS test are shown for tests that could have resulted in offer capping and tests that resulted in offer capping.

Overall, the results confirm that the three pivotal supplier test results in offer capping when the local market is structurally noncompetitive and does not result in offer capping when that is not the case. Local markets are noncompetitive when the number of suppliers is relatively small.

44 See the *MMU Technical Reference for PJM Markets*, at "Three Pivotal Supplier Test" for a more detailed explanation of the three pivotal supplier test. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

Table 3-26 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owners passing and failing for the transfer interface constraints.

Table 3-26 Three pivotal supplier test details for interface constraints: January 1 through March 31, 2017

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
AEP - DOM	Peak	341	87	7	0	7
	Off Peak	225	173	7	0	7
AP South	Peak	492	650	14	0	14
	Off Peak	431	645	11	0	10
Bedington - Black Oak	Peak	158	255	14	5	9
	Off Peak	105	99	8	1	7
Seneca	Peak	132	138	1	0	1
	Off Peak	150	162	1	0	1

Table 3-27 Summary of three pivotal supplier tests applied for interface constraints: January 1 through March 31, 2017

Constraint	Period	Total Tests Applied	Total Tests that Could Have Resulted in Offer Capping	Percent Total Tests that Could Have Resulted in Offer Capping	Total Tests Resulted in Offer Capping	Percent Total Tests Resulted in Offer Capping	Tests Resulted in Offer Capping as Percent of Tests that Could Have Resulted in Offer Capping
AEP - DOM	Peak	1	1	100%	0	0%	0%
	Off Peak	95	53	56%	7	7%	13%
AP South	Peak	166	88	53%	10	6%	11%
	Off Peak	384	178	46%	9	2%	5%
Bedington - Black Oak	Peak	23	20	87%	2	9%	10%
	Off Peak	140	93	66%	7	5%	8%
Seneca	Peak	341	2	1%	0	0%	0%
	Off Peak	477	0	0%	0	0%	NA

The three pivotal supplier test is applied every time the PJM market system solution indicates that incremental relief is needed to relieve a transmission constraint. While every system solution that requires incremental relief to transmission constraints will result in a test, not all tested providers of effective supply are eligible for capping. Steam units that are offer capped in the Day-Ahead Energy Market continue to be offer capped in the Real-Time Energy Market regardless of their inclusion in the TPS test in real time and the outcome of the TPS test in real time. Only uncommitted resources, which would be started as a result of incremental relief needs, are eligible to be offer capped. Already committed units that can provide incremental relief cannot, regardless of test score, be switched from price to cost offers. Table 3-27 provides, for the identified interface constraints, information on total tests applied, the subset of three pivotal supplier tests that could have resulted in the offer capping of uncommitted units and the portion of those tests that did result in offer capping uncommitted units. The three pivotal supplier tests that resulted in offer capping do not explain all the offer capped units in the Real-Time Energy Market. PJM operators also manually commit units for reliability reasons that are not specifically for providing relief to a binding constraint.

Parameter Limited Schedules

Cost-Based Offers

All capacity resources in PJM are required to submit at least one cost-based offer. During the 2016/2017 and 2017/2018 delivery years, all cost-based offers, submitted by resources that are not capacity performance resources, are parameter limited in accordance with the Parameter Limited Schedule (PLS) matrix or with the level of an approved exception.[45] During the 2016/2017 and 2017/2018 delivery years, all cost-based offers, submitted by capacity performance resources, are parameter limited in accordance with predetermined unit specific parameter limits. During the 2016/2017 and 2017/2018 delivery years, there was no base capacity procured.

For the 2018/2019 and 2019/2020 delivery years, PJM procured two types of capacity resources, capacity performance resources and base capacity

45 See PJM, OATT, § 6.6 Minimum Generator Operating Parameters - Parameter-Limited Schedules, (September 10, 2014), pp. 1937- 1940.

resources. Beginning June 1, 2018, there will no longer be any resources committed as the current annual capacity product. All cost-based offers, submitted by capacity performance resources and base capacity resources, are parameter limited in accordance with predetermined unit specific parameter limits.

Price-Based Offers

All capacity resources that choose to offer price-based offers are required to make available at least one price-based parameter limited offer (referred to as price-based PLS). For resources that are not capacity performance resources or not base capacity resources, the price-based parameter limited schedule is to be used by PJM for committing generation resources when a maximum emergency generation alert is declared. For capacity performance resources, the price-based parameter limited schedule is to be used by PJM for committing generation resources when hot weather alerts and cold weather alerts are declared. For base capacity resources (during the 2018/2019 and 2019/2020 delivery years only), the price-based parameter limited schedule is to be used by PJM for committing generation resources when hot weather alerts are declared.

Parameter Limits

During the extreme cold weather conditions in the first three months of 2016, as well as 2015 and 2014, a number of gas fired generators requested temporary exceptions to parameter limits for their parameter limited schedules due to restrictions imposed by natural gas pipelines. The parameters that were affected because of gas pipeline restrictions include minimum run time (MRT) and turn down ratio (TDR, the ratio of economic maximum MW to economic minimum MW). When pipelines issue critical notices and enforce ratable take requirements, generators may, depending on the nature of the transportation service purchased, be forced to nominate an equal amount of gas for each hour in a 24 hour period, with penalties for deviating from the nominated quantity. This led to requests for 24 hour minimum run times and turn down ratios close to 1.0, to avoid deviations from the hourly nominated quantity.

Key parameters like startup and notification time were not included in the PLS matrix in 2016 and prior periods for annual resources that do not have capacity performance obligations. Some resource owners notified PJM that they needed extended notification times based on the claimed necessity for generation owners to nominate gas prior to gas nomination cycle deadlines. Startup and notification times are limited for capacity performance resources beginning June 1, 2016, in accordance with predetermined unit specific parameter limits. The unit specific parameter limits for capacity performance resources were based on default minimum operating parameter limits posted by PJM by technology type. These default parameters were based on analysis by the MMU. Market participants could request an adjustment to the default values by submitting supporting documentation, which was reviewed by PJM and the MMU. The default minimum operating parameter limits or approved adjusted values are used by capacity performance resources for their parameter limited schedules.

PJM has the authority to approve adjusted parameters with input from the MMU. PJM has inappropriately applied different review standards to coal units than to CTs and CCs despite the objections of the MMU. PJM has approved parameter limits for steam units based on historical performance and existing equipment while holding CTs and CCs to higher standards based on OEM documentation and up to date equipment configuration.

Currently, there are no rules in the PJM tariff or manuals that limit the nonparameter attributes of price-based PLS offers. The intent of the price-based PLS offer is to prevent the exercise of market power during high demand conditions by preventing units from offering inflexible operating parameters in order to extract higher market revenues or higher uplift payments. However, a generator can include a higher markup in the price-based PLS offer than in the price-based non-PLS schedule. The result is that the offer is higher and market prices are higher as a result of the exercise of market power using the PLS offer. This defeats the purpose of requiring price-based PLS offers.

The MMU recommends that in order to ensure rigorous 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.

Parameter Limited Schedules under Capacity Performance

Beginning in the 2016/2017 delivery year, resources that have capacity performance (CP) commitments are required to submit, in their parameter limited schedules (cost-based offers and price-based PLS offers), unit specific parameters that reflect the physical capability of the technology type of the resource. For the 2018/2019 and 2019/2020 delivery years, resources that have base capacity commitments are also required to submit, in their parameter limited schedules, unit specific parameters that reflect the physical capability of the technology type of the resource. In its order on capacity performance, the Commission determined that capacity performance resources should be able to reflect actual constraints based on not just the resource physical constraints, but also other constraints, such as contractual limits that are not based on the physical characteristics of the generator.[46] The Commission directed that capacity performance resources with parameters based on nonphysical constraints should receive uplift payments.[47] The Commission directed PJM to submit tariff language to establish a process through which capacity performance resources that operate outside the defined unit-specific parameter limits can justify such operation and therefore remain eligible for make whole payments.[48]

A primary goal of the capacity performance market design is to assign performance risk to generation owners and to ensure that capacity prices reflect underlying supply and demand conditions, including the cost of taking on performance risk. The June 9th Order's determination on parameters is not consistent with that goal. By permitting generation owners to establish unit parameters based on nonphysical limits, the June 9th Order has weakened the incentives for units to be flexible and has weakened the assignment of performance risk to generation owners. Contractual limits, unlike generating unit operational limits, are a function of the interests and incentives of the parties to the contracts. If a generation owner expects to be compensated through uplift payments for running for 24 hours regardless of whether the energy is economic or needed, that generation owner has no incentive to pay more to purchase the flexible gas service that would permit the unit to be flexible in response to dispatch.

The fact that a contract may be just and reasonable because it was an arm's length contract entered into by two willing parties does not mean that is the only possible arrangement between the two parties or that it is consistent with an efficient market outcome or that such a contract can reasonably impose costs on customers who were not party to the contract. The actual contractual terms are a function of the incentives and interests of the parties. The fact that a just and reasonable contract exists between a generation owner and a gas supplier does not mean that it is appropriate or efficient to impose the resultant costs on electric customers or that it incorporates an efficient allocation of performance risk between the generation owner and other market participants.

The approach to parameters defined in the June 9th Order will increase energy market uplift payments substantially. Uplift costs are unpredictable, opaque and unhedgeable. While some uplift is necessary and efficient in an LMP market, this uplift is not. Electric customers are not in a position to determine the terms of the contracts that resources enter into. Customers rely on the market rules to create incentives that protect them by assigning operational risk to generators, who are in the best position to efficiently manage those risks.

The MMU recommends that the revised rules 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 reflected in uplift payments. The parameters provided to PJM dispatchers each day should reflect what units are physically capable of. That is an operational necessity. However, the parameters which determine the amount of uplift payments to

46 *PJM Interconnection, L.L.C. et al.*, 151 FERC ¶ 61,208 at P 437 (June 9th Order).
47 *Id* at P 439.
48 *Id* at P 440.

those generators should reflect the flexibility goals of the capacity performance construct and the assignment of performance risk to generation owners.

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. This solution creates the incentives for flexibility and preserves, to the extent possible, the incentives to follow PJM's dispatch instructions during high demand conditions. The proposed operating parameters should be based on the physical capability of the Reference Resource used in the Cost of New Entry, currently two GE Frame 7FA turbines with dual fuel capability. All resources that are less flexible than the Reference Resource are expected to be scheduled and running during high demand conditions anyway, while the flexible CTs that are used as peaking plants would still have the incentive to follow LMP and dispatch instructions. CCs would also have the capability to be as flexible as the reference resource. These units will be exempt from nonperformance charges and made whole as long as they perform in accordance with their parameters. This ensures that all the peaking units that are needed by PJM for flexible operation do not self schedule at their maximum output, and follow PJM dispatch instructions during high demand conditions. If any of the less flexible resources need to be dispatched down by PJM for reliability reasons, they would be exempt from nonperformance charges.

Such an approach is consistent with the Commission's no excuses policy for nonperformance because the flexibility target is set based on the optimal OEM-defined capability for the marginal resource that is expected to meet peak demand, which is consistent with the level of performance that customers are paying for in the capacity market. Any resource that is less flexible is not excused for nonperformance and any resource that meets the flexibility target is performing according to the commitments made in the capacity market.

The June 9th Order pointed out that the way to ensure that a resource's parameters are exposed to market consequences is to not allow any parameter limitations as an excuse for nonperformance. The same logic should apply to energy market uplift rules. A resource's parameters should be exposed to market consequences and the resource should not be made whole if it is operating less flexibly than the reference resource. Paying energy market uplift on the basis of parameters consistent with the flexibility goals of the capacity performance construct would ensure that performance incentives are consistent across the capacity and energy markets and ensure that performance risk is appropriately assigned to generation owners.

Markup Index

Markup is a summary measure of participant offer behavior or conduct for individual units. The markup index for each marginal unit is calculated as (Price – Cost)/Price.[49] The markup index is normalized and can vary from -1.00 when the offer price is less than short run marginal cost, to 1.00 when the offer price is higher than short run marginal cost. The markup index does not measure the impact of unit markup on total LMP. The dollar markup for a unit is the difference between price and cost.

Real-Time Markup

Table 3-28 shows the average markup index of marginal units in the Real-Time Energy Market, by offer price category using unadjusted cost offers. Table 3-29 shows the average markup index of marginal units in the Real-Time Energy Market, by offer price category using adjusted cost offers. The unadjusted markup is the difference between the price offer and the cost offer including the 10 percent adder in the cost offer. The adjusted markup is the difference between the price offer and the cost offer excluding the 10 percent adder from the cost offer. The adjusted markup is calculated for coal, gas and oil units because these units have consistently had price-based offers less than cost-based offers.[50] The markup is negative if the cost-based offer of the marginal unit exceeds its price-based offer at its operating point.

49 In order to normalize the index results (i.e., bound the results between +1.00 and -1.00) for comparison across both low and high cost units, the index is calculated as (Price – Cost)/Price when price is greater than cost, and (Price – Cost)/Cost when price is less than cost.

50 The MMU will calculate adjusted markup for gas units also in future reports because gas units also more consistently have price-based offers less than cost-based offers.

In the first three months of 2017, 91.4 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 (-$0.36 per MWh) when using unadjusted cost offers. The average dollar markups of units with offer prices between $25 and $50 was positive ($0.95 per MWh) when using unadjusted cost offers. Negative markup means the unit is offering to run at a price less than its cost-based offer, implying 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. Among the units that were marginal in the first three months of 2017, none had offer prices above $400 per MWh. Among the units that were marginal in the first three months of 2016, none had offer prices greater than $400 per MWh. Using the unadjusted cost offers, the highest markup for any marginal unit in the first three months of 2017 was $235.44 while the highest markup in the first three months of 2016 was $216.98.

Table 3-28 Average, real-time marginal unit markup index (By offer price category unadjusted): January 1 through March 31, 2016 and 2017

	2016 (Jan-Mar)			2017 (Jan-Mar)		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $25	(0.00)	($1.41)	65.7%	0.33	($0.36)	63.9%
$25 to $50	(0.05)	($3.19)	24.0%	0.05	$0.95	27.5%
$50 to $75	0.11	$6.82	1.7%	0.28	$16.10	1.3%
$75 to $100	0.23	$19.84	0.7%	0.07	$5.72	1.1%
$100 to $125	0.05	$5.83	2.0%	0.25	$27.11	0.2%
$125 to $150	0.01	$0.91	5.5%	0.43	$56.87	0.2%
>= $150	0.20	$37.17	0.4%	0.01	$1.46	5.8%

Table 3-29 Average, real-time marginal unit markup index (By offer price category adjusted): January 1 through March 31, 2016 and 2017

	2016 (Jan-Mar)			2017 (Jan-Mar)		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $25	0.08	$0.28	65.7%	0.41	$1.32	63.9%
$25 to $50	0.04	($0.01)	24.0%	0.14	$3.71	27.5%
$50 to $75	0.19	$11.57	1.7%	0.34	$19.86	1.3%
$75 to $100	0.30	$25.99	0.7%	0.16	$13.57	1.1%
$100 to $125	0.14	$15.85	2.0%	0.32	$34.62	0.2%
$125 to $150	0.11	$12.83	5.5%	0.48	$63.79	0.2%
>= $150	0.28	$49.61	0.4%	0.11	$16.04	5.8%

Table 3-30 shows the percentage of marginal units that had markups, calculated using unadjusted cost offers, below, above and equal to zero for coal, gas and oil fuel types.[51] Table 3-31 shows the percentage of marginal units that had markups, calculated using adjusted cost offers, below, above and equal to zero for coal, gas and oil fuel types. In the first three months of 2017, using unadjusted cost-based offers for coal units, 43.65 percent of coal units had negative markups. In the first three months of 2017, using adjusted cost-based offers for coal units, 22.81 percent of coal units had negative markups.

Table 3-30 Percent of marginal units with markup below, above and equal to zero (By fuel type unadjusted): January 1 through March 31, 2016 and 2017

	2016 (Jan-Mar)			2017 (Jan-Mar)		
Type/Fuel	Negative	Zero	Positive	Negative	Zero	Positive
Coal	63.56%	19.63%	16.81%	43.65%	26.81%	29.54%
Gas	19.74%	20.48%	59.78%	39.40%	10.67%	49.92%
Oil	1.07%	92.54%	6.39%	3.34%	96.09%	0.56%

Table 3-31 Percent of marginal units with markup below, above and equal to zero (By fuel type adjusted): January 1 through March 31, 2016 and 2017

	2016 (Jan-Mar)			2017 (Jan-Mar)		
Type/Fuel	Negative	Zero	Positive	Negative	Zero	Positive
Coal	52.29%	2.23%	45.48%	22.81%	8.36%	68.83%
Gas	5.36%	3.77%	90.87%	6.08%	3.16%	90.77%
Oil	0.00%	0.00%	100.00%	0.00%	0.00%	100.00%

51 Other fuel types were excluded based on data confidentiality rules.

Figure 3-27 shows the frequency distribution of hourly markups for all gas units offered in the first three months of 2016 and 2017. The highest markup within the economic operating range of the unit's offer curve was used for creating the frequency distributions.[52] Of the gas units offered in the PJM market in the first three months of 2017, nearly 28 percent of gas unit-hours had a maximum markup that was negative. More than seven percent of gas fired unit-hours had a highest markup within the economic operating range above $100 per MWh.

Figure 3-27 Frequency distribution of highest markup of gas units offered in January 1 through March 31, 2016 and 2017

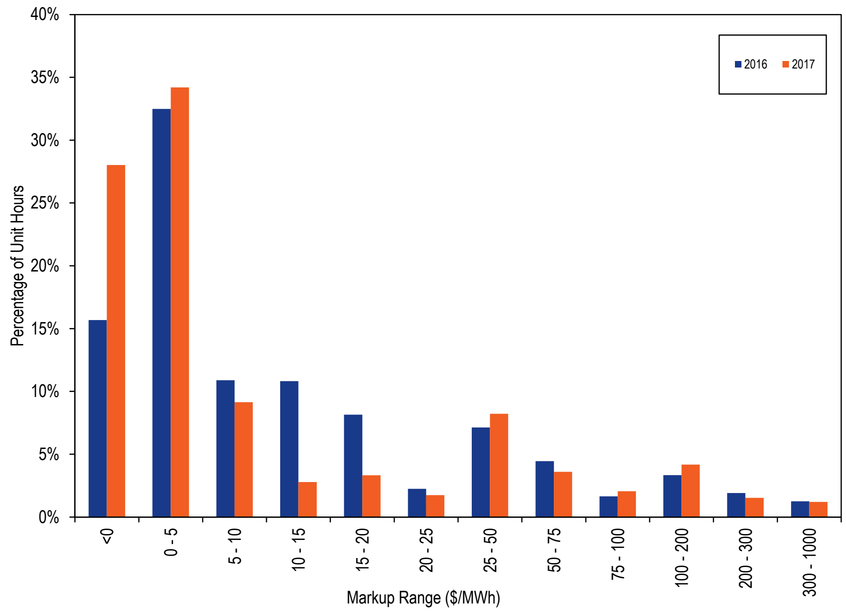


Figure 3-28 shows the frequency distribution of hourly markups for all coal units offered in the first three months of 2016 and 2017. Of the coal units offered in the PJM market in the first three months of 2017, nearly 41 percent of coal unit-hours had a maximum markup that was negative.

Figure 3-28 Frequency distribution of highest markup of coal units offered in January 1 through March 31, 2016 and 2017

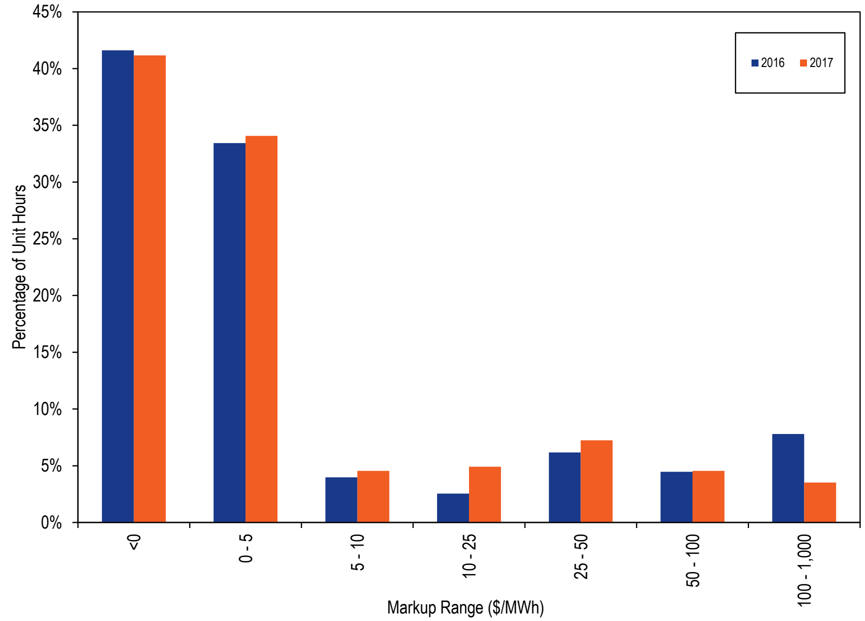


Figure 3-29 shows the frequency distribution of hourly markups for all offered oil units in the first three month of 2016 and 2017. Of the oil units offered in the PJM market in the first three months of 2017, nearly 51 percent of oil unit-hours had a maximum markup that was negative.

52 The categories in the frequency distribution were chosen so as to maintain data confidentiality.

Figure 3-29 Frequency distribution of highest markup of oil units offered in January 1 through March 31, 2016 and 2017

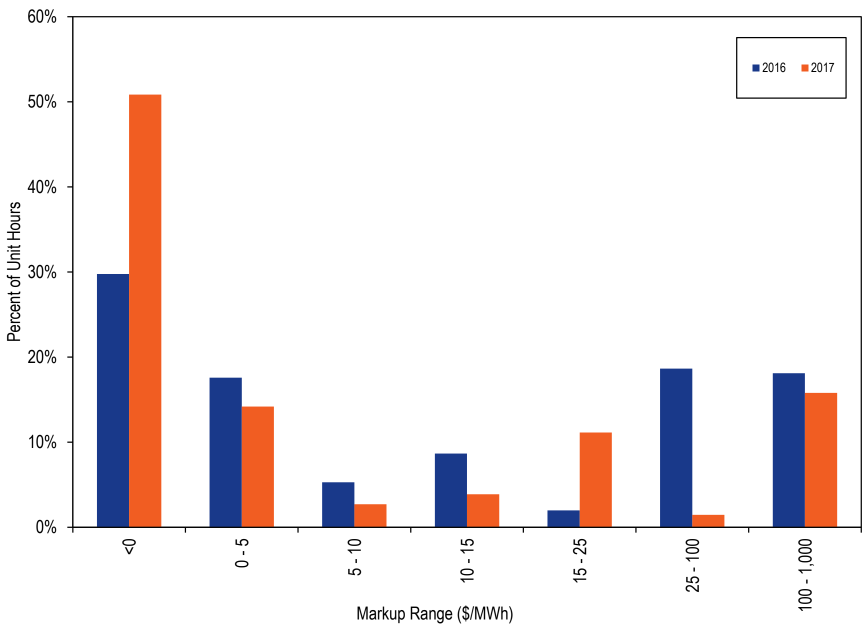
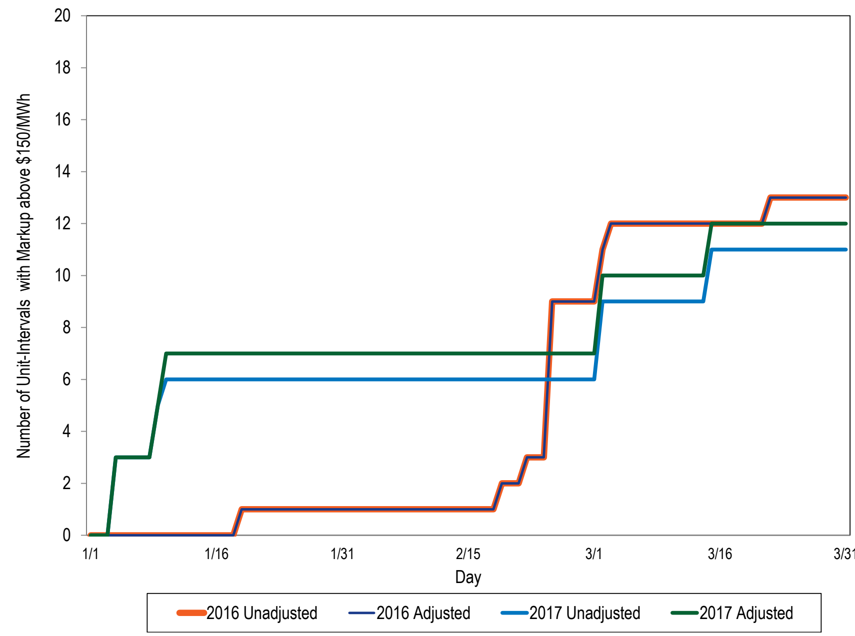


Figure 3-30 Cumulative number of unit intervals with markups above $150 per MWh: January 1 through March 31, 2016 and 2017



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 imply 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.

Figure 3-30 and Figure 3-32 show the number of marginal unit intervals in the first three months of 2017 and 2016 with markup above $150 per MWh.

Day-Ahead Markup

Table 3-32 shows the average markup index of marginal generating units in the Day-Ahead Energy Market, by offer price category using unadjusted offers. The majority of marginal units are virtual transactions, which do not have markup. In the first three months of 2017, 89.3 percent of marginal generating units had offer prices less than $50 per MWh and the average dollar markup was positive, and the 1.1 percent of marginal generating units had offers in the $75 to $100 per MWh range and the average dollar markup was positive.

Table 3-32 Average day-ahead marginal unit markup index (By offer price category, unadjusted): January 1 through March 31, 2016 and 2017

	2016 (Jan - Mar)			2017 (Jan - Mar)		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $25	0.06	($0.43)	58.8%	0.24	$0.59	55.6%
$25 to $50	(0.03)	($1.91)	28.1%	0.08	$2.23	33.7%
$50 to $75	0.05	$2.94	2.6%	0.05	$2.60	1.2%
$75 to $100	0.06	$4.41	0.2%	0.00	$0.25	1.1%
$100 to $125	0.00	$0.33	0.7%	0.00	$0.00	0.0%
$125 to $150	0.00	$0.01	9.5%	0.00	$0.00	0.0%
>= $150	0.00	$0.00	0.0%	(0.00)	($0.06)	8.4%

Table 3-33 shows the average markup index of marginal generating units in the Day-Ahead Energy Market, by offer price category using adjusted offers. In the first three months of 2017, 1.1 percent of marginal generating units had offers between $75 and $100 per MWh and the average dollar markup and the average markup index were both positive. The average markup index increased from 0.13 in the first three months of 2016, to 0.32 in the first three months of 2017 in the offer price category less than $25.

Table 3-33 Average day-ahead marginal unit markup index (By offer price category, adjusted): January 1 through March 31, 2016 and 2017

	2016 (Jan - Mar)			2017 (Jan - Mar)		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $25	0.13	$1.36	58.8%	0.32	$2.39	55.6%
$25 to $50	0.05	$1.20	28.1%	0.15	$4.77	33.7%
$50 to $75	0.13	$7.77	2.6%	0.13	$7.16	1.2%
$75 to $100	0.14	$11.49	0.2%	0.09	$8.78	1.1%
$100 to $125	0.09	$11.09	0.7%	0.00	$0.00	0.0%
$125 to $150	0.09	$11.96	9.5%	0.09	$11.86	0.0%
>= $150	0.00	$0.00	0.0%	0.09	$14.51	8.4%

Energy Market Cost-Based Offers

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 structure 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 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.

Short Run Marginal Costs

There are three types of costs identified under PJM rules:

- Short run marginal costs (or incremental costs). Short run costs incurred directly as a result of producing energy for an hour;
- Avoidable costs. Annual costs that would be avoided if energy were not produced over an annual period;
- Fixed costs. Costs associated with an investment in a facility including the return on and of capital.

Marginal costs are the only costs relevant to the energy market. Specifically, the competitive energy offer level is the short run marginal cost of production.

The MMU recommends that PJM require that the level of incremental costs includable in cost-based offers not exceed the unit's short run marginal cost.

Fuel Cost Policies

The fuel cost policy documents the process by which the Market Seller calculates the fuel cost component of its cost-based offers. Short run marginal fuel costs include commodity costs, transportation costs, fees, and taxes for the purchase of fuel. Fuel handling costs and fuel additive costs are included in the cost-based offer as variable operations and maintenance (VOM) costs. The fuel cost policy documents the frequency with which the Market Seller updates VOM and other nonfuel cost inputs.

The verification of accurate fuel costs in cost-based offers is not possible unless the fuel cost policy is algorithmic, verifiable, and systematic. Algorithmic means that the fuel cost policy must use a set of defined, logical steps to use defined inputs to get to defined outputs. Verifiable means that the fuel cost policy must provide a fuel price that can be calculated by the Market Monitor after the fact with the same data available to the generation owner at the time the decision was made, and documentation for that data from a public or a private source. Systematic means that the fuel cost policy must document a standardized method or methods for calculating fuel costs including objective triggers for each method.

The MMU recommends that PJM require that all fuel cost policies be algorithmic, verifiable, and systematic.

Cost Development Guidelines

The Cost Development Guidelines contained in PJM Manual 15 do not clearly or accurately describe the short run marginal cost of generation. 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.

FERC System of Accounts

PJM Manual 15 relies heavily on the FERC System of Accounts, which predates markets and does not define costs consistently with market economics.

The MMU recommends removal of all use of the FERC System of Accounts in the Cost Development Guidelines.

Cyclic Starting and Peaking Factors

The use of cyclic starting and peaking factors for calculating VOM costs for combined cycles and combustion turbines is designed to allocate a greater proportion of long term maintenance costs to starts and the tail block of the cost curve. The use of such factors is not appropriate given that long term maintenance costs are not short run marginal costs and should not be included in cost offers.

The MMU recommends the removal of all cyclic starting and peaking factors from the Cost Development Guidelines.

Labor Costs

PJM Manual 15 allows for the inclusion of plant staffing costs in energy market cost offers. This is inappropriate given that labor costs are avoidable costs, not short run marginal costs, and are correctly includable in the RPM Avoidable Cost Rate.

The MMU recommends the removal of all labor costs from the Cost Development Guidelines.

Combined Cycle Start Heat Input Definition

PJM Manual 15 defines the start heat input of combined cycles as the amount of fuel used from the firing of the first combustion turbine to the close of the steam turbine breaker plus any fuel used by other combustion turbines in the combined cycle from firing to the point at which the HRSG steam pressure matches the steam turbine steam pressure. This definition is inappropriate given that after each combustion turbine is synchronized, some of the fuel is used to produce energy for which the resource is compensated in the energy market.

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. This change will make the treatment of combined cycles consistent with steam turbines.

Nuclear Costs

The fuel costs for nuclear plants are fixed in the short run and amortized over the period between refueling outages. The short run marginal cost of fuel for nuclear plants is zero. Operations and maintenance costs for nuclear power plants consist primarily of labor and maintenance costs incurred during outages, which are also fixed in the short run.

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.

Pumped Hydro Costs

The calculation of pumped hydro costs for energy storage in Section 7.3 of PJM Manual 15 is inaccurate. The mathematical formulation contains an error in the calculation of the weighted average pumping cost, and it does not take into account the purchase of power for pumping in the day-ahead market.

The MMU recommends revising the pumped hydro fuel cost calculation to include day-ahead and real-time power purchases.

Energy Market Opportunity Costs

The calculation of energy market opportunity costs for energy limited units in Section 12 of PJM Manual 15 fails to account for a number of physical unit characteristics and environmental restrictions that influence opportunity costs. These include start up time, notification time, minimum down time, multiple fuel capability, multiple emissions limitations, and fuel usage limitations.

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.

The use of Catastrophic Force Majeure as the criterion for the use of opportunity costs for fuel supply limitations in Schedule 2 of the Operating Agreement is overly restrictive. This criterion would not allow the use of opportunity costs to allocate limited fuel in the case of regional fuel transportation disruptions or extreme weather events.

The MMU recommends removing the catastrophic designation for force majeure fuel supply limitations in Schedule 2.

Frequently Mitigated Units (FMU) and Associated Units (AU)

An FMU is a frequently mitigated unit. The results reported here include units that were mitigated for any reason, including both structural market power in the energy market and units called on for reliability reasons, including reactive and black start service.

The FMU adder was filed with FERC in 2005, and approved effective February 2006.[53] The goal, in 2005, was to ensure that units that were offer capped for most of their run hours could cover their going forward or avoidable costs (also known as ACR in the PJM Capacity Market). That function became unnecessary with the introduction of the RPM capacity market design in 2007, and changes to the scarcity pricing rules in 2012. Under the RPM design, units can make offers in the capacity market that include their ACR net of net revenues. Thus, if there is a shortfall in ACR recovery, that shortfall is included in the RPM offer. If the unit clears in RPM, it covers its shortfall in ACR costs. If the unit does not clear, then the market result means that PJM can provide reliability without the unit and no additional revenue is needed.

For those reasons, the MMU recommended the elimination of FMU and AU adders.[54] FMU and AU adders no longer serve the purpose for which they were created and interfere with the efficient operation of PJM markets.

53 110 FERC ¶ 61,053 (2005).
54 See the "*FMU Problem Statement and Issue Charge*," <http://www.monitoringanalytics.com/reports/Presentations/2013/IMM_MIC_FMU_Problem_Statement_and_Issue_Charge_20130306.pdf>.

The MMU and PJM proposed a compromise on the elimination of FMU adders that maintains the ability of generating units to qualify for FMU adders when units have net revenues less than unit going forward costs or ACR. PJM submitted the joint MMU/PJM proposal to the Commission pursuant to section 206 of the Federal Power Act. On October 31, 2014, the Commission conditionally approved the filing and the new rule became effective November 1, 2014.

The definition of FMUs provides for a set of graduated adders associated with increasing levels of offer capping. Units capped for 60 percent or more of their run hours and less than 70 percent are eligible for an adder of either 10 percent of their cost-based offer or $20 per MWh. Units capped for 70 percent or more of their run hours and less than 80 percent are eligible for an adder of either 10 percent of their cost-based offer or $30 per MWh. Units capped for 80 percent or more of their run hours are eligible for an adder of either 10 percent of their cost-based offer or $40 per MWh. These categories are designated Tier 1, Tier 2 and Tier 3.

In addition to being offer capped for the designated percent of run hours, in order to qualify for an FMU adder, a generating unit's Projected PJM Market Revenues plus the unit's PJM capacity market revenues on a rolling 12-month basis, divided by the unit's MW of installed capacity (in $/MW-year) must be less than its accepted unit specific Avoidable Cost Rate (in $/MW-year) (excluding APIR and ARPIR), or its default Avoidable Cost Rate (in $/MW-year) if no unit-specific Avoidable Cost Rate is accepted for the BRAs for the Delivery Years included in the rolling 12-month period, determined pursuant to Sections 6.7 and 6.8 of Attachment DD of the Tariff. (The relevant Avoidable Cost Rate is the weighted average of the Avoidable Cost Rates for each Delivery Year included in the rolling 12-month period, weighted by month.) No portion of the unit may be included in an FRR capacity plan or be receiving compensation under Part V of the PJM Tariff and the unit must be internal to the PJM Region and subject only to PJM dispatch.[55]

An AU, or associated unit, is a unit that is physically, electrically and economically identical to an FMU, but does not qualify for the same FMU adder based on the number of run-hours the unit is offer capped.[56] For example, if a generating station had two identical units with identical electrical impacts on the system, one of which was offer capped for more than 80 percent of its run hours, that unit would be designated a Tier 3 FMU. If the second unit were capped for 30 percent of its run hours, that unit would be an AU and receive the same Tier 3 adder as the FMU at the site. The AU designation was implemented to ensure that the associated unit is not dispatched in place of the FMU, resulting in no effective adder for the FMU. In the absence of the AU designation, the associated unit would be an FMU after its dispatch and the FMU would be dispatched in its place after losing its FMU designation.

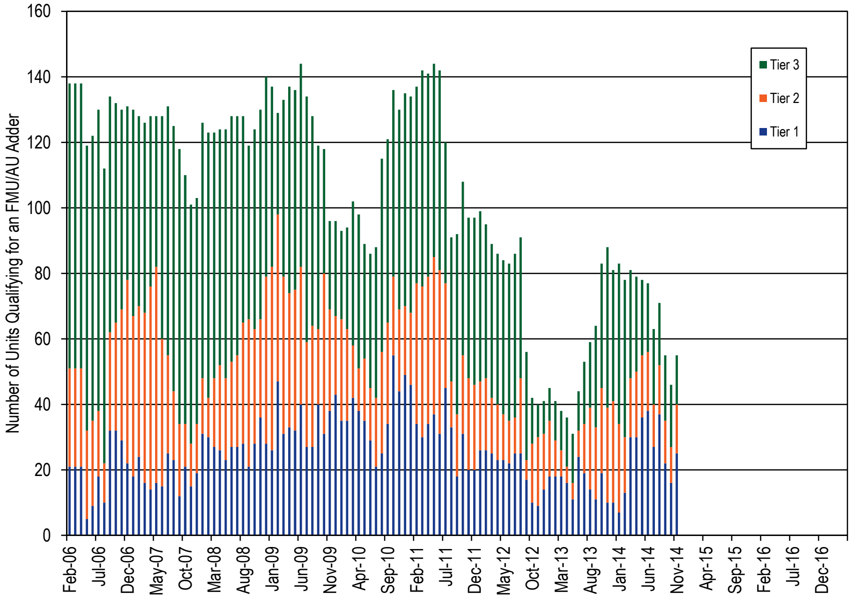
Figure 3-31 shows the total number of FMUs and AUs that qualified for an adder since the inception of the business rule in February 2006. The new rules for determining the qualification of a unit as an FMU or AU became effective November 1, 2014. FMUs and AUs are designated monthly, and a unit's capping percentage is based on a rolling 12-month average, effective with a one-month lag.[57] 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.

55 PJM. OA, Schedule 1 § 6.4.2.

56 An associated unit (AU) must belong to the same design class (where a design class includes generation that is the same size and uses the same technology, without regard to manufacturer) and uses the identical primary fuel as the FMU.

57 PJM. OA, Schedule 1 § 6.4.2. In 2007, the FERC approved OA revisions to clarify the AU criteria.

Figure 3-31 Frequently mitigated units and associated units (By month): February 1, 2006 through March 31, 2017



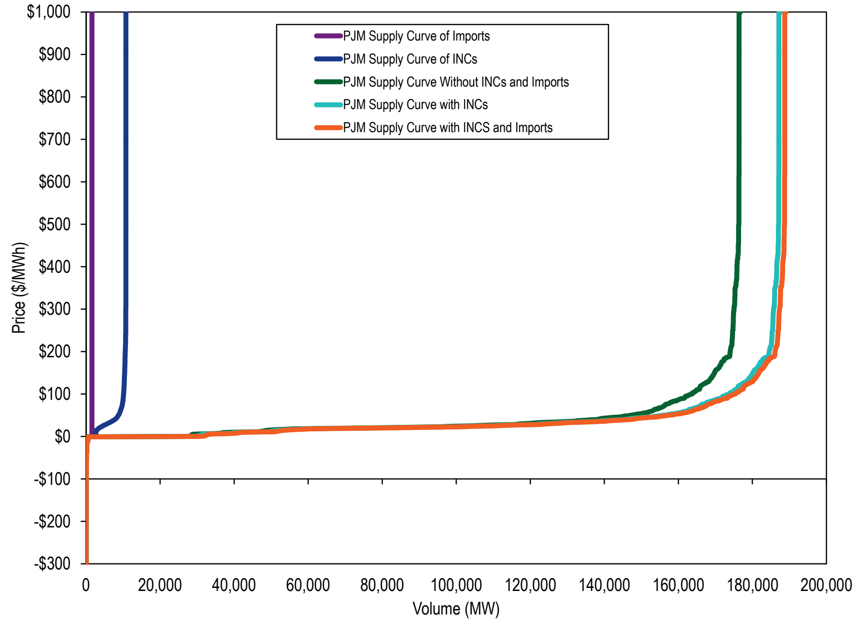
Virtual Offers and Bids

There is a substantial volume of virtual offers and bids in the PJM Day-Ahead Energy Market and such offers and bids may be marginal, based on the way in which the PJM optimization algorithm works.

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. Increment offers and decrement bids may be submitted at any hub, transmission zone, aggregate, or single bus for which LMP is calculated. Up to congestion transactions may be submitted between any two buses on a list of 431 buses, eligible for up to congestion transaction bidding.[58] Financial Transaction Rights (FTRs) bids may be submitted at any bus on a list of selected buses that change every planning period, eligible for FTRs. Import and export transactions may be submitted at any interface pricing point, where an import is equivalent to a virtual offer that is injected into PJM and an export is equivalent to a virtual bid that is withdrawn from PJM.

Figure 3-32 shows the PJM day-ahead daily aggregate supply curve of increment offers, the system aggregate supply curve of imports, the system aggregate supply curve without increment offers and imports, the system aggregate supply curve with increment offers, and the system aggregate supply curve with increment offers and imports for an example day in 2017.

Figure 3-32 PJM day-ahead aggregate supply curves: 2017 example day



58 Market participants were required to specify an interface pricing point as the source for imports, an interface pricing point as the sink for exports or an interface pricing point as both the source and sink for transactions wheeling through PJM. On November 1, 2012, PJM eliminated this requirement. For the list of eligible sources and sinks for up to congestion transactions, see www.pjm.com "*OASIS-Source-Sink-Link.xls*,"<http://www.pjm.com/~/media/etools/oasis/references/oasis-source-sink-link.ashx>.

Table 3-34 shows the hourly average number of cleared and submitted increment offers and decrement bids by month in 2016 and the first three months of 2017. The hourly average submitted and cleared increment MW increased by 40.3 and 30.4 percent, from 7,425 MW and 4,691 MW in the first three months of 2016 to 10,419 MW and 6,115 MW in the first three months of 2017. The hourly average submitted and cleared decrement MW increased by 22.5 percent and 4.5 percent, from 7,901 MW and 4,661 MW in the first three months of 2016 to 9,676 MW and 4,869 MW in the first three months of 2017.

Table 3-34 Hourly average number of cleared and submitted INCs, DECs by month: January 1, 2016 through March 31, 2017

	Increment Offers				Decrement Bids			
Year	Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume	Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume
2016 Jan	4,350	6,447	78	398	5,153	7,320	76	295
2016 Feb	4,754	7,109	116	578	4,511	7,445	72	409
2016 Mar	4,973	8,689	142	760	4,305	8,894	101	648
2016 Apr	4,511	6,351	187	558	3,453	6,990	84	451
2016 May	5,089	7,459	181	656	4,171	6,823	94	404
2016 Jun	4,592	7,043	143	697	4,196	6,696	89	410
2016 Jul	4,101	6,534	128	745	3,335	5,830	86	448
2016 Aug	4,457	6,956	135	749	3,433	5,506	74	398
2016 Sep	4,527	6,772	148	733	4,391	7,030	112	437
2016 Oct	4,631	7,112	199	846	3,990	6,757	112	462
2016 Nov	5,022	7,822	223	1,008	3,671	6,435	109	482
2016 Dec	5,102	7,775	189	1,010	4,028	6,869	129	486
2016 Annual	4,675	7,175	156	729	4,051	6,879	95	444
2017 Jan	5,855	10,169	205	1,288	4,811	9,753	136	821
2017 Feb	6,058	10,590	266	1,430	4,599	9,326	149	784
2017 Mar	6,427	10,516	312	1,669	5,170	9,915	170	1,019
2017 Annual	6,115	10,419	261	1,463	4,869	9,676	152	878

Table 3-35 shows the average hourly number of up to congestion transactions and the average hourly MW in 2016 and the first three months of 2017. In the first three months of 2017, the average hourly up to congestion submitted MW increased 30.1 percent and cleared MW increased 15.9 percent, compared to the first three months of 2016.

Table 3-35 Hourly average of cleared and submitted up to congestion bids by month: January 1, 2016 through March 31, 2017

	Up to Congestion			
Year	Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume
2016 Jan	39,639	135,369	2,466	6,015
2016 Feb	38,814	152,891	2,091	5,748
2016 Mar	31,817	148,162	1,703	5,101
2016 Apr	29,212	128,349	2,689	6,079
2016 May	32,883	120,132	2,977	6,006
2016 Jun	35,469	151,414	2,528	6,406
2016 Jul	37,668	181,720	2,413	7,158
2016 Aug	32,986	147,289	2,294	6,774
2016 Sep	29,368	129,498	2,309	6,065
2016 Oct	28,250	121,377	2,612	6,498
2016 Nov	36,506	141,491	2,927	7,324
2016 Dec	40,090	147,343	3,552	8,803
2016 Annual	34,387	142,075	2,549	6,503
2017 Jan	46,856	196,472	3,568	10,246
2017 Feb	41,841	207,994	2,711	8,309
2017 Mar	38,780	164,063	2,272	6,252
2017 Annual	42,516	188,905	2,855	8,269

Table 3-36 shows the average hourly number of import and export transactions and the average hourly MW in 2016 and first three months of 2017. In the first three months of 2017, the average hourly submitted and cleared import transaction MW decreased by 8.9 and 12.8 percent, and the average hourly submitted and cleared export transaction MW increased 9.3 and 4.2 percent, compared to the first three months of 2016.

Table 3-36 Hourly average day-ahead number of cleared and submitted import and export transactions by month: January 1, 2016 through March 31, 2017

	Imports				Exports			
Year	Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume	Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume
2016 Jan	2,633	2,103	20	20	3,044	2,571	16	16
2016 Feb	2,396	2,480	20	22	2,634	2,653	13	13
2016 Mar	2,097	2,145	17	18	2,324	2,330	11	11
2016 Apr	2,150	2,180	16	16	2,620	2,635	13	13
2016 May	1,889	1,947	12	14	2,484	2,492	14	15
2016 Jun	1,335	1,366	6	7	4,428	4,471	23	24
2016 Jul	1,315	1,247	6	6	4,327	3,389	21	21
2016 Aug	1,384	1,424	6	7	4,331	4,351	20	20
2016 Sep	939	956	5	5	3,997	4,004	21	21
2016 Oct	1,104	997	6	6	3,800	2,902	22	22
2016 Nov	1,012	1,030	6	7	2,883	2,894	17	17
2016 Dec	1,302	1,354	8	9	4,284	4,306	22	22
2016 Annual	1,628	1,600	11	11	3,434	3,250	18	17
2017 Jan	2,633	1,289	20	20	3,044	3,171	16	16
2017 Feb	2,396	1,418	20	8	2,634	3,552	13	19
2017 Mar	2,097	1,157	17	7	2,324	3,813	11	18
2017 Annual	1,560	1,600	10	11	3,499	3,510	17	17

Table 3-37 shows the frequency with which generation offers, import or export transactions, up to congestion transactions, decrement bids, increment offers and price-sensitive demand were marginal in January 1, 2016 through March 31, 2017.

Table 3-37 Type of day-ahead marginal units: January 1, 2016 through March 31, 2017

	2016						2017				
	Generation	Dispatchable Transaction	Up to Congestion Transaction	Decrement Bid	Increment Offer	Price Sensitive Demand	Generation	Dispatchable Transaction	Up to Congestion Transaction	Decrement Bid	Increment Offer
Jan	5.3%	0.1%	85.2%	5.6%	3.8%	0.0%	3.2%	0.0%	85.3%	7.7%	3.7%
Feb	5.5%	0.0%	83.5%	7.4%	3.6%	0.0%	4.9%	0.0%	83.9%	6.5%	4.6%
Mar	7.0%	0.1%	80.6%	7.7%	4.7%	0.0%	4.3%	0.1%	81.5%	8.5%	5.6%
Apr	5.8%	0.0%	82.3%	8.1%	3.7%	0.0%					
May	6.2%	0.1%	83.8%	6.5%	3.4%	0.0%					
Jun	3.5%	0.0%	84.2%	8.5%	3.7%	0.0%					
Jul	3.0%	0.0%	83.1%	10.1%	3.7%	0.0%					
Aug	3.1%	0.0%	78.4%	13.1%	5.4%	0.0%					
Sep	6.1%	0.0%	76.3%	11.4%	6.2%	0.0%					
Oct	6.1%	0.1%	77.0%	10.9%	5.9%	0.0%					
Nov	4.0%	0.0%	86.5%	6.3%	3.1%	0.0%					
Dec	3.1%	0.0%	86.6%	6.9%	3.3%	0.0%					
Annual	4.7%	0.0%	82.4%	8.6%	4.2%	0.0%	4.1%	0.0%	83.7%	7.6%	4.6%

Figure 3-33 shows the monthly volume of bid and cleared INC, DEC and up to congestion bids by month for 2005 through the first three months of 2017.

Figure 3-33 Monthly bid and cleared INCs, DECs and UTCs (MW): January 1, 2005 through March 31, 2017

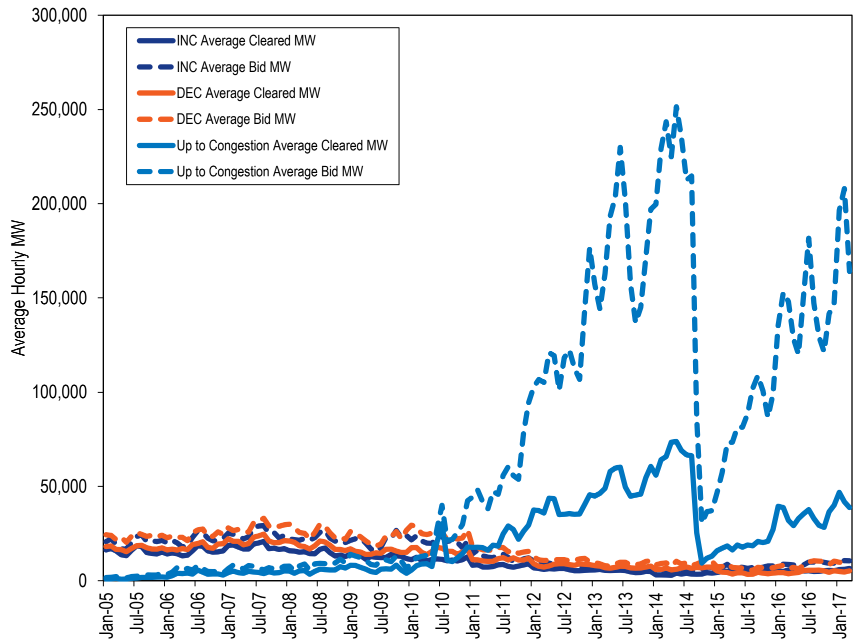
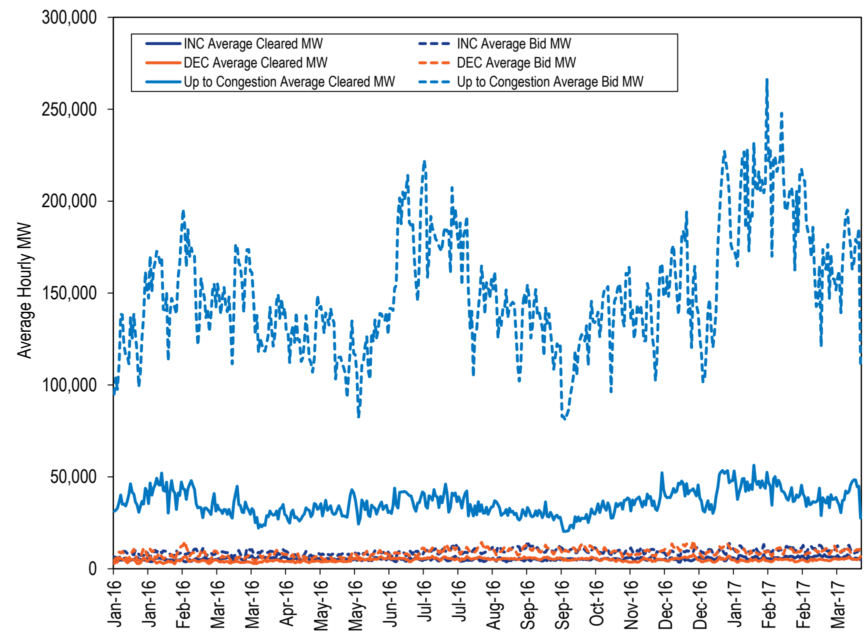


Figure 3-34 shows the daily volume of bid and cleared INC, DEC and up to congestion bids for the period 2016 through the first three months of 2017.

Figure 3-34 Daily bid and cleared INCs, DECs, and UTCs (MW): January 1, 2016 through March 31, 2017



In order to evaluate the ownership of virtual bids, the MMU categorizes all participants making virtual bids in PJM as either physical or financial. Physical entities include utilities and customers which primarily take physical positions in PJM markets. Financial entities include banks and hedge funds which primarily take financial positions in PJM markets. International market participants that primarily take financial positions in PJM markets are generally considered to be financial entities even if they are utilities in their own countries.

Table 3-38 shows, in the first three months of 2016 and 2017, the total increment offers and decrement bids and cleared MW by whether the parent organization is financial or physical.

Table 3-38 PJM INC and DEC bids and cleared MW by type of parent organization (MW): January 1 through March 31, 2016 and 2017

	Jan-Mar 2016				Jan-Mar 2017			
Category	Total Virtual Bid MW	Percent	Total Virtual Cleared MW	Percent	Total Virtual Bid MW	Percent	Total Virtual Cleared MW	Percent
Financial	18,035,687	52.3%	6,268,151	31.0%	24,827,459	57.2%	9,688,435	40.9%
Physical	16,435,855	47.7%	13,982,822	69.0%	18,560,931	42.8%	14,026,693	59.1%
Total	34,471,542	100.0%	20,250,973	100.0%	43,388,390	100.0%	23,715,128	100.0%

Table 3-39 shows, in the first three months of 2016 and 2017, the total up to congestion bids and cleared MW by whether the parent organization was financial or physical.

Table 3-39 PJM up to congestion transactions by type of parent organization (MW): January 1 through March 31, 2016 and 2017

	Jan-Mar 2016				Jan-Mar 2017			
Category	Total Up to Congestion Bid MW	Percent	Total Up to Congestion Cleared MW	Percent	Total Up to Congestion Bid MW	Percent	Total Up to Congestion Cleared MW	Percent
Financial	295,275,386	93.1%	71,891,904	89.7%	400,356,768	98.2%	88,612,664	96.5%
Physical	21,935,772	6.9%	8,235,260	10.3%	7,488,886	1.8%	3,178,964	3.5%
Total	317,211,158	100.0%	80,127,163	100.0%	407,845,654	100.0%	91,791,629	100.0%

Table 3-40 shows, in the first three months of 2016 and 2017, the total import and export transactions by whether the parent organization was financial or physical.

Table 3-40 PJM import and export transactions by type of parent organization (MW): January 1 through March 31, 2016 and 2017

		Jan-Mar 2016		Jan-Mar 2017	
	Category	Total Import and Export MW	Percent	Total Import and Export MW	Percent
Day-Ahead	Financial	19,015,698	39.9%	5,109,129	46.9%
	Physical	28,635,508	60.1%	5,790,217	53.1%
	Total	47,651,206	100.0%	10,899,346	100.0%
Real-Time	Financial	25,595,400	30.4%	6,928,946	38.4%
	Physical	58,569,000	69.6%	11,095,123	61.6%
	Total	84,164,400	100.0%	18,024,069	100.0%

Table 3-41 shows increment offers and decrement bids bid by top 10 locations in the first three months of 2016 and 2017.

Table 3-41 PJM virtual offers and bids by top 10 locations (MW): January 1 through March 31, 2016 and 2017

Jan-Mar 2016					Jan-Mar 2017				
Aggregate/Bus Name	Aggregate/Bus Type	INC MW	DEC MW	Total MW	Aggregate/Bus Name	Aggregate/Bus Type	INC MW	DEC MW	Total MW
WESTERN HUB	HUB	5,403,807	5,218,719	10,622,527	WESTERN HUB	HUB	6,169,328	4,965,019	11,134,347
SOUTHIMP	INTERFACE	1,503,450	0	1,503,450	SOUTHIMP	INTERFACE	1,504,206	0	1,504,206
N ILLINOIS HUB	HUB	189,476	589,534	779,010	MISO	INTERFACE	83,285	1,136,449	1,219,734
NYIS	INTERFACE	466,833	253,568	720,401	AEP-DAYTON HUB	HUB	943,957	185,449	1,129,406
BGE	ZONE	96,804	612,646	709,450	NYIS	INTERFACE	388,256	441,364	829,620
AEP-DAYTON HUB	HUB	321,804	173,426	495,230	N ILLINOIS HUB	HUB	120,502	590,226	710,728
IMO	INTERFACE	426,618	1,050	427,668	BGE	ZONE	169,858	455,246	625,103
SOUTHEXP	INTERFACE	0	415,678	415,678	FOWLER 34.5 KV FWL2-1WF	GEN	170,451	356,677	527,127
LINDENVFT	INTERFACE	874	380,395	381,269	DCKCRKCE345 KV UN1 DYN	GEN	333,180	193,444	526,624
MISO	INTERFACE	131,637	208,923	340,560	FOWLER 34.5 KV FWLR1AWF	GEN	76,342	405,828	482,171
Top ten total		8,541,304	7,853,939	16,395,243			9,959,365	8,729,701	18,689,067
PJM total		18,437,329	16,034,213	34,471,542			22,495,581	20,892,809	43,388,390
Top ten total as percent of PJM total		46.3%	49.0%	47.6%			44.3%	41.8%	43.1%

Table 3-42 shows up to congestion transactions by import bids for the top 10 locations and associated profits at each path in the first three months of 2016 and 2017.[59]

59 The source and sink aggregates in these tables refer to the name and location of a bus and do not include information about the behavior of any individual market participant.

Table 3-42 PJM cleared up to congestion import bids by top 10 source and sink pairs (MW): January 1 through March 31, 2016 and 2017

Jan-Mar 2016							
Imports							
Source	Source Type	Sink	Sink Type	MW	Source Profit	Sink Profit	UTC Profit
MISO	INTERFACE	COOK	EHVAGG	242,432	$168,662	($114,928)	$53,734
HUDSONTP	INTERFACE	LEONIA 230 T-2	AGGREGATE	182,923	$644,527	($640,838)	$3,689
OVEC	INTERFACE	CONESVILLE 5	AGGREGATE	180,391	$304,760	($259,032)	$45,728
OVEC	INTERFACE	CABOT	EHVAGG	178,741	$234,845	($162,667)	$72,178
MISO	INTERFACE	112 WILTON	EHVAGG	171,689	$102,843	($25,225)	$77,618
SOUTHWEST	INTERFACE	DUMONT	EHVAGG	150,019	$159,478	($103,274)	$56,204
NEPTUNE	INTERFACE	SOUTHRIV 230	AGGREGATE	146,950	$92,597	($15,352)	$77,245
MISO	INTERFACE	CHICAGO GEN HUB	HUB	128,058	$169,196	($169,821)	($626)
OVEC	INTERFACE	COOK	EHVAGG	125,000	$147,679	($91,827)	$55,852
NORTHWEST	INTERFACE	POWERTON 5-6	AGGREGATE	118,597	$138,234	$12,222	$150,456
Top ten total				1,624,800	$2,162,821	($1,570,743)	$592,078
PJM total				8,037,920	$11,266,571	($7,728,186)	$3,538,385
Top ten total as percent of PJM total				20.2%	19.2%	20.3%	16.7%
Jan-Mar 2017							
Imports							
Source	Source Type	Sink	Sink Type	MW	Source Profit	Sink Profit	UTC Profit
MISO	INTERFACE	COOK	EHVAGG	361,736	$166,034	($276,119)	($110,085)
HUDSONTP	INTERFACE	LEONIA 230 T-2	AGGREGATE	314,191	($13,069)	$15,272	$2,203
OVEC	INTERFACE	BUCKEYE - AEP	AGGREGATE	179,081	$82,546	($83,839)	($1,293)
SOUTHEAST	INTERFACE	WILLIAMSPORT - AP	AGGREGATE	173,267	$91,472	($74,636)	$16,836
SOUTHIMP	INTERFACE	COOK	EHVAGG	157,299	($121,473)	($180,807)	($302,281)
MISO	INTERFACE	AELC	AGGREGATE	132,837	($10,816)	$17,199	$6,383
OVEC	INTERFACE	DEOK	ZONE	128,389	($18,719)	$24,950	$6,231
SOUTHEAST	INTERFACE	SCOTTSVI 138 KV T1T2	AGGREGATE	126,678	$193,979	($183,452)	$10,527
NYIS	INTERFACE	HUDSON BC	AGGREGATE	118,598	$185,364	($165,910)	$19,454
NYIS	INTERFACE	PSEG	ZONE	116,500	($34,404)	$38,065	$3,661
Top ten total				1,808,574	$520,913	($869,276)	($348,364)
PJM total				7,606,307	$4,613,702	($4,592,928)	$20,774
Top ten total as percent of PJM total				23.8%	11.3%	18.9%	(1676.9%)

Table 3-43 shows up to congestion transactions by export bids for the top 10 locations and associated profits at each path in the first three months of 2016 and 2017.

Table 3-43 PJM cleared up to congestion export bids by top 10 source and sink pairs (MW): January 1 through March 31, 2016 and 2017

Jan-Mar 2016							
Exports							
Source	Source Type	Sink	Sink Type	MW	Source Profit	Sink Profit	UTC Profit
COMED	ZONE	NIPSCO	INTERFACE	397,071	$425,560	($173,232)	$252,328
21 KINCA ATR24304	AGGREGATE	NIPSCO	INTERFACE	269,188	$362,997	($208,900)	$154,097
SULLIVAN-AEP	EHVAGG	OVEC	INTERFACE	267,964	$608,470	($483,421)	$125,049
SOMERVIL 230 KV T-2	AGGREGATE	NEPTUNE	INTERFACE	138,665	$113,267	($164,488)	($51,222)
UNIV PARK 1-6	AGGREGATE	NIPSCO	INTERFACE	131,157	$59,659	$20,372	$80,030
EAST BEND 2	AGGREGATE	SOUTHWEST	INTERFACE	129,678	$173,707	($194,746)	($21,039)
NAGELAEP	EHVAGG	SOUTHEXP	INTERFACE	127,681	$267,255	($208,045)	$59,210
21 KINCA ATR24404	AGGREGATE	SOUTHWEST	INTERFACE	113,339	$109,427	($156,454)	($47,027)
21 KINCA ATR24304	AGGREGATE	SOUTHWEST	INTERFACE	109,798	$276,731	($218,547)	$58,184
MADISON	AGGREGATE	SOUTHWEST	INTERFACE	103,633	$63,444	($32,621)	$30,823
Top ten total				1,788,174	$2,460,517	($1,820,084)	$640,434
PJM total				6,032,764	$6,272,078	($5,255,836)	$1,016,242
Top ten total as percent of PJM total				29.6%	39.2%	34.6%	63.0%
Jan-Mar 2017							
Exports							
Source	Source Type	Sink	Sink Type	MW	Source Profit	Sink Profit	UTC Profit
21 KINCA ATR24304	AGGREGATE	SOUTHWEST	INTERFACE	311,464	$285,782	($241,403)	$44,380
COMED	ZONE	NIPSCO	INTERFACE	224,622	$314,886	($170,316)	$144,570
QUAD CITIES 2	AGGREGATE	MISO	INTERFACE	216,386	$122,618	($73,908)	$48,710
ROCKPORT	EHVAGG	SOUTHWEST	INTERFACE	199,820	$69,343	($88,012)	($18,669)
GENEVA	AGGREGATE	NIPSCO	INTERFACE	174,512	$219,375	($144,847)	$74,528
WAUKEGAN TR412	AGGREGATE	NIPSCO	INTERFACE	126,589	$147,085	($84,125)	$62,959
JEFFERSON	EHVAGG	NIPSCO	INTERFACE	124,869	$155,137	($76,213)	$78,924
QUAD CITIES 2	AGGREGATE	NORTHWEST	INTERFACE	120,095	$72,763	$5,803	$78,566
QUAD CITIES 1	AGGREGATE	NORTHWEST	INTERFACE	111,835	$24,173	($2,710)	$21,463
21 KINCA ATR24304	AGGREGATE	NIPSCO	INTERFACE	105,652	$87,414	($8,118)	$79,295
Top ten total				1,715,844	$1,498,576	($883,850)	$614,725
PJM total				6,043,159	$3,958,509	($2,504,066)	$1,454,443
Top ten total as percent of PJM total				28.4%	37.9%	35.3%	42.3%

Table 3-44 shows up to congestion transactions by wheel bids and associated profits at each path for the top 10 locations in the first three months of 2016 and 2017.

Table 3-44 PJM cleared up to congestion wheel bids by top 10 source and sink pairs (MW): January 1 through March 31, 2016 and 2017

Jan-Mar 2016							
Wheels							
Source	Source Type	Sink	Sink Type	MW	Source Profit	Sink Profit	UTC Profit
NORTHWEST	INTERFACE	MISO	INTERFACE	139,843	$249,475	($82,485)	$166,991
MISO	INTERFACE	NIPSCO	INTERFACE	133,330	$172,964	($67,117)	$105,848
SOUTHWEST	INTERFACE	SOUTHEXP	INTERFACE	74,640	$90,875	($62,491)	$28,384
NYIS	INTERFACE	IMO	INTERFACE	64,680	$57,359	$5,834	$63,193
MISO	INTERFACE	NORTHWEST	INTERFACE	56,605	$24,639	$69,209	$93,849
IMO	INTERFACE	NYIS	INTERFACE	53,799	$40,161	($56,622)	($16,461)
SOUTHWEST	INTERFACE	NIPSCO	INTERFACE	41,078	$67,873	($29,490)	$38,383
HUDSONTP	INTERFACE	NYIS	INTERFACE	23,450	($114,659)	$110,743	($3,916)
MISO	INTERFACE	SOUTHEXP	INTERFACE	21,489	$27,041	($21,030)	$6,011
IMO	INTERFACE	MISO	INTERFACE	21,422	$25,558	($25,695)	($137)
Top ten total				630,337	$641,288	($159,143)	$482,144
PJM total				717,476	$830,005	($283,709)	$546,296
Top ten total as percent of PJM total				87.9%	77.3%	56.1%	88.3%
Jan-Mar 2017							
Wheels							
Source	Source Type	Sink	Sink Type	MW	Source Profit	Sink Profit	UTC Profit
MISO	INTERFACE	NIPSCO	INTERFACE	121,431	$191,057	($93,183)	$97,874
NORTHWEST	INTERFACE	MISO	INTERFACE	74,099	$132,188	($42,843)	$89,344
SOUTHWEST	INTERFACE	SOUTHEXP	INTERFACE	58,499	$7,560	($15,442)	($7,882)
MISO	INTERFACE	NORTHWEST	INTERFACE	58,162	$9,107	($35,970)	($26,862)
SOUTHWEST	INTERFACE	NIPSCO	INTERFACE	32,795	$62,414	($66,816)	($4,401)
OVEC	INTERFACE	SOUTHWEST	INTERFACE	15,251	($14,424)	$16,256	$1,832
SOUTHEAST	INTERFACE	SOUTHEXP	INTERFACE	11,446	$20,552	($255)	$20,297
NORTHWEST	INTERFACE	NIPSCO	INTERFACE	10,843	$6,122	($2,751)	$3,371
NYIS	INTERFACE	HUDSONTP	INTERFACE	9,055	$12,885	($13,316)	($431)
SOUTHIMP	INTERFACE	MISO	INTERFACE	7,565	$24,233	($15,705)	$8,529
Top ten total				399,146	$451,695	($270,024)	$181,671
PJM total				471,556	$449,391	($247,475)	$201,916
Top ten total as percent of PJM total				84.6%	100.5%	109.1%	90.0%

On November 1, 2012, PJM eliminated the requirement for market participants to specify an interface pricing point as either the source or sink of an up to congestion transaction. The top 10 internal up to congestion transaction locations were 6.2 percent of the PJM total internal up to congestion transactions in the first three months of 2017.

Table 3-45 shows up to congestion transactions by internal bids for the top 10 locations and associated profits at each path in the first three months of 2016 and 2017. The total UTC profit by top 10 locations increased by $716,481, from $26,800 in the first three months of 2016 to $743,281 in the first three months of 2017. The total internal cleared MW increased by 12.3 million MW, or 18.9 percent, from 65.3 million MW in the first three months of 2016 to 77.7 million MW in the first three months of 2017.

Table 3-45 PJM cleared up to congestion internal bids by top 10 source and sink pairs (MW): January 1 through March 31, 2016 and 2017

Jan-Mar 2016							
Internal							
Source	Source Type	Sink	Sink Type	MW	Source Profit	Sink Profit	UTC Profit
112 WILTON	EHVAGG	DUMONT	EHVAGG	586,362	$368,797	($412,765)	($43,968)
BERGEN 2CC	AGGREGATE	LEONIA 230 T-1	AGGREGATE	576,605	$1,663,972	($1,675,613)	($11,640)
21 KINCA ATR24404	AGGREGATE	MICHFE	AGGREGATE	507,970	$288,707	($411,863)	($123,156)
ROCKPORT	EHVAGG	JEFFERSON	EHVAGG	410,366	$447,955	($392,689)	$55,266
21 KINCA ATR24404	AGGREGATE	DUMONT - OLIVE	AGGREGATE	359,025	$393,800	($321,276)	$72,524
21 KINCA ATR24304	AGGREGATE	DUMONT - OLIVE	AGGREGATE	337,626	$558,197	($521,474)	$36,723
WHIPPANY BK 7	AGGREGATE	TRAYNOR	AGGREGATE	336,485	$169,224	($163,878)	$5,346
MOUNTAINEER	EHVAGG	COOK	EHVAGG	269,624	$438,348	($325,005)	$113,343
JEFFERSON	EHVAGG	COOK	EHVAGG	256,334	$243,410	($149,691)	$93,719
BLACKOAK	EHVAGG	BEDINGTON	EHVAGG	251,293	$313,916	($485,270)	($171,354)
Top ten total				3,891,689	$4,886,325	($4,859,525)	$26,800
PJM total				65,339,002	$82,606,618	($67,059,522)	$15,547,096
Top ten total as percent of PJM total				6.0%	5.9%	7.2%	.2%
Jan-Mar 2017							
Internal							
Source	Source Type	Sink	Sink Type	MW	Source Profit	Sink Profit	UTC Profit
DUMONT	EHVAGG	COOK	EHVAGG	1,298,185	$937,776	($705,680)	$232,096
21 KINCA ATR24304	AGGREGATE	SULLIVAN-AEP	EHVAGG	443,188	$457,131	($151,381)	$305,749
BERGEN 2CC	AGGREGATE	LEONIA 230 T-1	AGGREGATE	410,312	$59,210	($57,514)	$1,695
QUAD CITIES 1	AGGREGATE	CORDOVA	AGGREGATE	407,562	$308,209	($331,363)	($23,154)
FE GEN	AGGREGATE	ATSI	ZONE	400,736	($117,126)	$165,617	$48,491
QUAD CITIES 2	AGGREGATE	CORDOVA	AGGREGATE	392,311	$518,419	($526,891)	($8,472)
HOMERCIT	AGGREGATE	AEC - PN	AGGREGATE	371,257	$208,356	($196,756)	$11,600
AEP-DAYTON HUB	HUB	N ILLINOIS HUB	HUB	369,685	$125,216	($225,655)	($100,439)
BAKER	EHVAGG	AMP-OHIO	AGGREGATE	367,064	$138,765	($17,670)	$121,095
CAYUGA RIDGE S WF	AGGREGATE	AELC	AGGREGATE	367,017	$438,857	($284,238)	$154,619
Top ten total				4,827,318	$3,074,811	($2,331,530)	$743,281
PJM total				77,670,606	$34,862,468	($27,757,531)	$7,104,937
Top ten total as percent of PJM total				6.2%	8.8%	8.4%	10.5%

Table 3-46 shows the number of source-sink pairs that were offered and cleared monthly in 2013 through March 2017. The annual row in Table 3-46 is the average hourly number of offered and cleared source-sink pairs for the year for the average columns and the maximum hourly number of offered and cleared source-sink pairs for the year for the maximum columns. The increase in average offered and cleared source-sink pairs beginning in January 2013 and continuing through the first eight months of 2014 illustrates that PJM's modification of the rules governing the location of up to congestion transactions bids resulted in a significant increase in the number of offered and cleared up to congestion transactions. The subsequent reduction in up to congestion transactions (UTC) that followed a FERC order setting September 8, 2014, as the effective date for any uplift charges subsequently assigned to UTCs, was reversed. There was an increase in up to congestion volume as a result of the expiration of the fifteen month refund period for the proceeding related to uplift charges for UTC transactions on December 7, 2015.[60]

60 See 148 FERC ¶ 61,144 (2014)..

Table 3-46 Number of PJM offered and cleared source and sink pairs: January 2013 through March 2017

		Daily Number of Source-Sink Pairs			
Year	Month	Average Offered	Max Offered	Average Cleared	Max Cleared
2013	Jan	6,580	10,548	3,291	5,060
2013	Feb	4,891	7,415	2,755	3,907
2013	Mar	4,858	7,446	2,868	4,262
2013	Apr	6,426	9,064	3,464	4,827
2013	May	5,729	7,914	3,350	4,495
2013	Jun	6,014	8,437	3,490	4,775
2013	Jul	5,955	9,006	3,242	4,938
2013	Aug	6,215	9,751	3,642	5,117
2013	Sep	3,496	4,222	2,510	3,082
2013	Oct	4,743	7,134	3,235	4,721
2013	Nov	8,605	14,065	5,419	8,069
2013	Dec	8,346	11,728	6,107	7,415
2013	Annual	5,996	14,065	3,620	8,069
2014	Jan	7,977	11,191	5,179	7,714
2014	Feb	10,087	11,688	7,173	8,463
2014	Mar	11,360	14,745	7,284	9,943
2014	Apr	11,487	14,106	8,589	10,253
2014	May	11,215	13,477	7,734	9,532
2014	Jun	10,613	14,112	7,374	10,143
2014	Jul	10,057	12,304	7,202	8,486
2014	Aug	10,877	12,863	7,609	9,254
2014	Sep	5,618	11,269	4,281	8,743
2014	Oct	2,871	4,092	1,972	2,506
2014	Nov	2,463	3,988	1,812	3,163
2014	Dec	2,803	3,672	2,197	2,786
2014	Annual	8,109	10,614	5,690	7,570
2015	Jan	3,337	5,422	2,263	3,270
2015	Feb	4,600	7,041	2,775	4,147
2015	Mar	4,061	5,799	2,625	3,244
2015	Apr	3,777	6,967	2,343	3,378
2015	May	4,025	5,513	2,587	3,587
2015	Jun	3,852	5,967	2,781	3,748
2015	Jul	3,957	5,225	2,786	4,044
2015	Aug	4,996	6,143	3,702	4,378
2015	Sep	5,775	7,439	4,222	5,462
2015	Oct	6,000	7,414	4,221	5,397
2015	Nov	5,846	7,148	4,494	5,842
2015	Dec	7,097	8,250	5,709	6,610
2015	Annual	4,259	6,152	2,897	3,912
2016	Jan	7,714	8,793	6,174	7,374
2016	Feb	9,200	11,172	7,203	7,957
2016	Mar	8,826	11,572	6,338	8,126
2016	Apr	7,697	8,473	5,958	6,767
2016	May	8,521	9,398	6,707	7,273
2016	Jun	9,261	10,948	6,913	7,770
2016	Jul	12,401	16,103	8,571	11,695
2016	Aug	12,464	13,576	8,725	9,224
2016	Sep	12,297	16,324	7,736	9,230
2016	Oct	11,248	13,114	7,648	8,539
2016	Nov	13,151	16,725	8,173	11,581
2016	Dec	12,688	15,868	8,101	9,630
2016	Annual	10,455	12,672	7,354	8,764
2017	Jan	11,893	13,258	7,785	8,839
2017	Feb	9,337	11,902	6,756	7,758
2017	Mar	7,795	8,776	6,051	7,001
2017	Jan-Mar	9,675	11,312	6,864	7,866

Table 3-47 and Figure 3-35 show total cleared up to congestion transactions by type in the first three months of 2016 and 2017. Total up to congestion transactions in the first three months of 2017 increased by 14.6 percent from 80.1 million MW in the first three months of 2016 to 91.8 million MW in the first three months of 2017. Internal up to congestion transactions in the first three months of 2017 were 84.6 percent of all up to congestion transactions compared to 81.5 percent in the first three months of 2016.

Table 3-47 PJM cleared up to congestion transactions by type (MW): January 1 through March 31, 2016 and 2017

	Jan-Mar 2016				
	Cleared Up to Congestion Bids				
	Import	Export	Wheel	Internal	Total
Top ten total (MW)	1,624,800	1,788,174	630,337	3,891,689	7,935,000
PJM total (MW)	8,037,920	6,032,764	717,476	65,339,002	80,127,162
Top ten total as percent of PJM total	20.2%	29.6%	87.9%	6.0%	9.9%
PJM total as percent of all up to congestion transactions	10.0%	7.5%	0.9%	81.5%	100.0%
	Jan-Mar 2017				
	Cleared Up to Congestion Bids				
	Import	Export	Wheel	Internal	Total
Top ten total (MW)	1,808,574	1,715,844	399,416	4,827,318	8,751,152
PJM total (MW)	7,606,307	6,043,159	471,556	77,670,606	91,791,628
Top ten total as percent of PJM total	23.8%	28.4%	84.7%	6.2%	9.5%
PJM total as percent of all up to congestion transactions	8.3%	6.6%	0.5%	84.6%	100.0%

Figure 3-35 shows the initial increase and continued increase in internal up to congestion transactions by month following the November 1, 2012 rule change permitting such transactions, until September 8, 2014. The reduction in up to congestion transactions (UTC) that followed a FERC order setting September 8, 2014, as the effective date for any uplift charges subsequently assigned to UTCs, was reversed. There was an increase in up to congestion volume as a result of the expiration of the fifteen month refund period for the proceeding related to uplift charges for UTC transactions.[61]

Figure 3-35 PJM monthly cleared up to congestion transactions by type (MW): January 1, 2005 through March 1, 2017

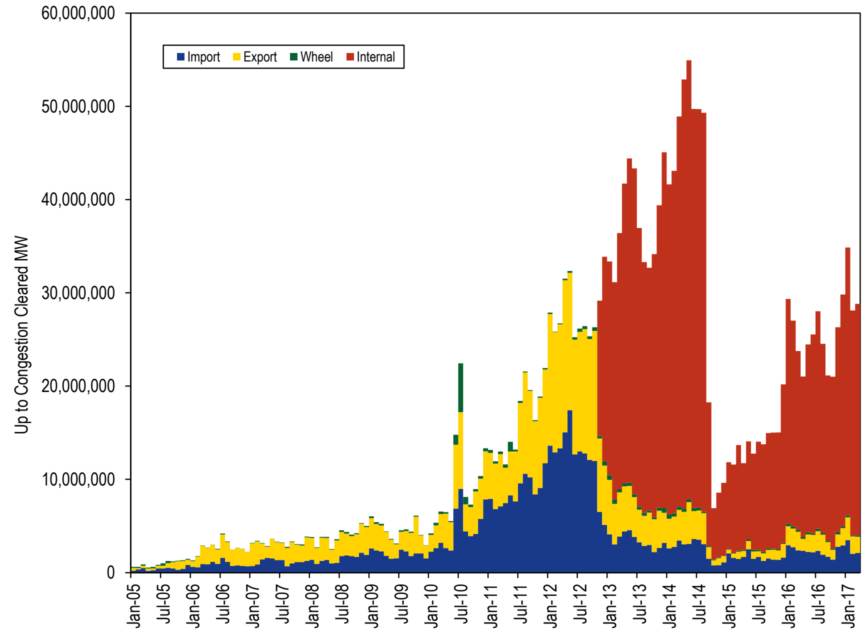
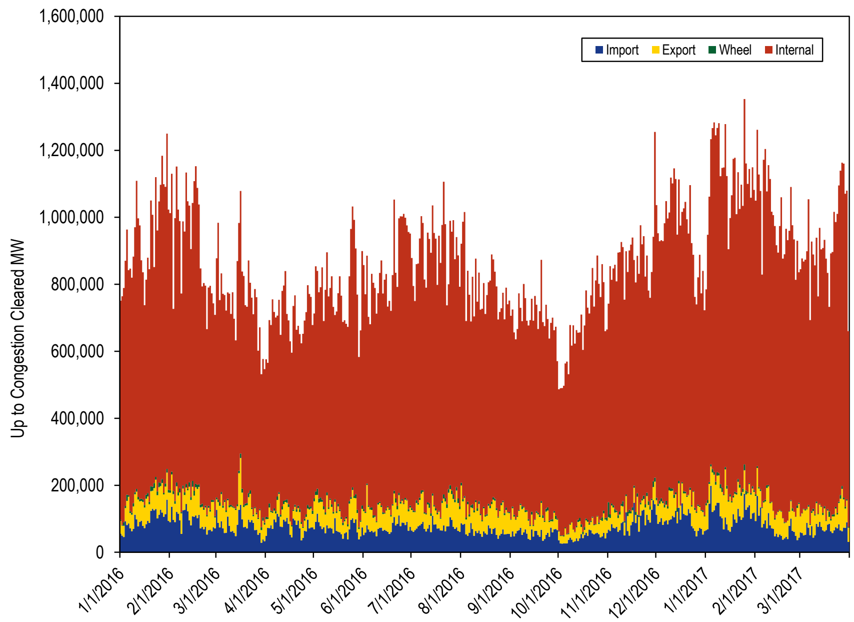


Figure 3-36 shows the daily cleared up to congestion MW by transaction type for the period from January 2016 through March 2017.

61 See 148 FERC ¶ 61,144 (2014).

Figure 3-36 PJM daily cleared up to congestion transaction by type (MW): January 1, 2016 through March 31, 2017



Generator Offers

Generator offers are categorized as dispatchable (Table 3-48) or self scheduled (Table 3-49).[62] Units which are available for economic dispatch are dispatchable. Units which are self scheduled to generate fixed output are self scheduled and must run. Units which are self scheduled at their economic minimum and are available for economic dispatch up to their economic maximum are self scheduled and dispatchable. Table 3-48 and Table 3-49 do not include units that did not indicate their offer status and units that were offered as available to run only during emergency events. Units that do not indicate their offer status are unavailable for dispatch by PJM. The MW offered beyond the economic range of a unit are categorized as emergency MW. Emergency MW are included in both tables.

Table 3-48 shows the proportion of MW offers by dispatchable units, by unit type and by offer price range, in the first three months of 2017. For example, 78.4 percent of CC offers were dispatchable and in the $0 to $200 per MWh price range. The total column is the proportion of all MW offers by unit type that were dispatchable. For example, 83.5 percent of all CC MW offers were dispatchable, including the 4.6 percent of emergency MW offered by CC units. The all dispatchable offers row is the proportion of MW that were offered as available for economic dispatch within a given range by all unit types. For example, 52.6 percent of all dispatchable offers were in the $0 to $200 per MWh price range. The total column in the all dispatchable offers row is the proportion of all MW offers that were offered as available for economic dispatch, including emergency MW. Among all the generator offers in the first three months of 2017, 57.1 percent were offered as available for economic dispatch.

62 Each range in the tables is greater than or equal to the lower value and less than the higher value. The unit type battery is not included in these tables because batteries do not make energy offers. The unit type fuel cell is not included in these tables because of the small number owners and the small number of units of this type of generation.

Table 3-48 Distribution of MW for dispatchable unit offer prices: January 1 through March 31, 2017

	Dispatchable (Range)							
Unit Type	($200) - $0	$0 - $200	$200 - $400	$400 - $600	$600 - $800	$800 - $1,000	Emergency	Total
CC	0.0%	78.4%	0.2%	0.1%	0.0%	0.1%	4.6%	83.5%
CT	0.0%	84.4%	4.8%	1.3%	0.0%	0.0%	8.7%	99.2%
Diesel	0.0%	37.0%	18.9%	2.4%	0.1%	0.0%	16.9%	75.4%
Fuel Cell	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Nuclear	0.0%	6.6%	0.0%	0.0%	0.0%	0.0%	0.0%	6.6%
Pumped Storage	69.4%	0.0%	0.0%	0.0%	0.0%	0.0%	1.8%	71.2%
Run of River	0.2%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%
Solar	56.8%	2.9%	0.0%	0.0%	0.0%	0.0%	0.0%	59.8%
Steam	0.1%	54.6%	0.1%	0.1%	0.0%	0.5%	2.6%	58.1%
Transaction	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Wind	55.8%	8.4%	0.0%	0.0%	0.0%	0.0%	0.4%	64.6%
All Dispatchable Offers	3.0%	52.6%	1.0%	0.3%	0.0%	0.2%	3.6%	60.7%

Table 3-49 Distribution of MW for self scheduled and dispatchable unit offer prices: January 1 through March 31, 2017

	Self Scheduled		Self Scheduled and Dispatchable (Range)							
Unit Type	Must Run	Emergency	($200) - $0	$0 - $200	$200 - $400	$400 - $600	$600 - $800	$800 - $1,000	Emergency	Total
CC	2.5%	0.5%	0.3%	11.2%	0.0%	0.0%	0.0%	0.0%	2.0%	16.5%
CT	0.1%	0.0%	0.0%	0.5%	0.0%	0.0%	0.0%	0.0%	0.1%	0.8%
Diesel	21.2%	1.0%	2.2%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	24.6%
Fuel Cell	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%
Nuclear	82.7%	1.0%	8.6%	1.0%	0.0%	0.0%	0.0%	0.0%	0.0%	93.4%
Pumped Storage	16.4%	8.0%	2.1%	0.0%	0.0%	0.0%	0.0%	0.0%	2.3%	28.8%
Run of River	62.6%	15.9%	0.4%	18.8%	0.0%	0.0%	0.0%	0.0%	2.1%	99.8%
Solar	28.0%	8.7%	3.4%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	40.2%
Steam	3.9%	1.3%	0.2%	34.8%	0.0%	0.0%	0.0%	0.0%	1.8%	41.9%
Transaction	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Wind	2.6%	2.4%	23.8%	3.3%	0.0%	0.0%	0.0%	0.0%	3.3%	35.4%
All Self-Scheduled Offers	19.1%	1.2%	2.3%	15.5%	0.0%	0.0%	0.0%	0.0%	1.2%	39.3%

Table 3-49 shows the proportion of MW offers by unit type that were self scheduled to generate fixed output and by unit type and price range for self-scheduled and dispatchable units, for the first three months of 2017. For example, 11.2 percent of CC offers were self scheduled and dispatchable and in the $0 to $200 price range. The total column is the proportion of all MW offers by unit type that were self scheduled to generate fixed output and are self scheduled and dispatchable. For example, 16.5 percent of all CC MW offers were either self scheduled to generate at fixed output or self scheduled to generate at economic minimum and dispatchable up to economic maximum, including the 2.0 percent of emergency MW offered by CC units. The all self scheduled offers row is the proportion of MW that were offered as either self scheduled to generate at fixed output or self scheduled to generate at economic minimum and dispatchable up to economic maximum within a given range by all unit types. For example, units that were self scheduled to generate at fixed output accounted for 19.1 percent of all offers and self scheduled and dispatchable units accounted for 17.8 percent of all offers. The total column in the all self scheduled offers row is the proportion of all MW offers that were either self scheduled to generate at fixed output or self scheduled to generate at economic minimum and dispatchable up to economic maximum, including emergency MW. Among all the generator offers in of the first three months of 2017, 20.3 percent were offered as self scheduled and 19.0 percent were offered as self scheduled and dispatchable.

Market Performance

The PJM average locational marginal price (LMP) reflects the configuration of the entire RTO. The PJM Energy Market includes the Real-Time Energy Market and the Day-Ahead Energy Market.

Markup

The markup index is a measure of participant conduct for individual marginal units. The markup in dollars is a measure of the impact of participant behavior on the generator bus market price when a unit is marginal. As an example, if unit A has a $90 cost and a $100 price, while unit B has a $9 cost and a $10 price, both would show a markup index of 10 percent, but the price impact of unit A's markup at the generator bus would be $10 while the price impact of unit B's markup at the generator bus would be $1. Depending on each unit's location on the transmission system, those bus-level impacts could also translate to different impacts on total system price. Markup can also affect prices when units with high markups are not marginal.

The MMU calculates the impact on system prices of marginal unit price-cost markup, based on analysis using sensitivity factors. The calculation shows the markup component of LMP based on a comparison between the price-based offer and the cost-based offer of each actual marginal unit on the system.[63]

The MMU calculated an explicit measure of the impact of marginal unit markups on LMP using the mathematical relationships among LMPs given the market solution. The markup impact includes the impact of the identified markup conduct on a unit by unit basis, but the inclusion of negative markup impacts has an offsetting effect. The markup analysis does not distinguish between intervals in which a unit has local market power or has a price impact in an unconstrained interval. The markup analysis is a more general measure of the competitiveness of the energy market.

The price impact of markup must be interpreted carefully. The markup calculation is not based on a full redispatch of the system to determine the marginal units and their marginal costs that would have occurred if all units had made all offers at short run marginal cost. The results do not reflect a counterfactual market outcome based on the assumption that all units made all offers at short run marginal cost. It is important to note that a full redispatch analysis is practically impossible and a limited redispatch analysis would not be dispositive. Nonetheless, such a hypothetical counterfactual analysis would reveal the extent to which the actual system dispatch is less than competitive if it showed a difference between dispatch based on short run marginal cost and actual dispatch. It is possible that the unit-specific markup, based on a redispatch analysis, would be lower than the markup component of price if the reference point were an inframarginal unit with a lower price and a higher cost than the actual marginal unit. If the actual marginal unit has short run marginal costs that would cause it to be inframarginal, a new unit would be marginal. If the offer of that new unit were greater than the cost of the original marginal unit, the markup impact would be lower than the MMU measure. If the newly marginal unit is on a price-based schedule, the analysis would have to capture the markup impact of that unit as well.

63 This is the same method used to calculate the fuel cost adjusted LMP and the components of LMP. *See* Calculation and Use of Generator Sensitivity/Unit Participation Factors, 2010 State of the Market Report for PJM: Technical Reference for PJM Markets.

Real-Time Markup

Markup Component of Real-Time Price by Fuel, Unit Type

The markup component of price is the difference between the system price, when the system price is determined by the active offers of the marginal units, whether price or cost-based, and the system price, based on the cost-based offers of those marginal units.

Table 3-50 shows the average unit markup component of LMP for marginal units, by unit type and primary fuel. The markup component of LMP is a measure of the impact of the markups of marginal units shown in Table 3-50 on the system-wide load-weighted LMP. The negative markup components of LMP reflect the negative markups shown in the Table 3-28.

All generating units, including coal units, are allowed to add an additional 10 percent to their cost offer. The additional 10 percent was included in the definition of cost offers prior to the implementation of PJM markets in 1999, based on the uncertainty of calculating the hourly operating costs of CTs under changing ambient conditions. Coal units do not face the same cost uncertainty as gas-fired CTs. A review of actual participant behavior supports this view, as the owners of coal units, facing competition, typically exclude the additional 10 percent from their actual offers. The unadjusted markup is calculated as the difference between the price offer and the cost offer including the additional 10 percent in the cost offer for coal units. The adjusted markup is calculated as the difference between the price offer and the cost offer excluding the additional 10 percent from the cost offer. Even the adjusted markup overestimates the negative markup because coal units facing increased competitive pressure have excluded both the 10 percent and some or all components of operating and maintenance cost. While both these elements are permitted under the definition of cost-based offers in the PJM Market Rules, they are not part of a competitive offer because they are not actually short run marginal costs, and actual market behavior reflected that fact.[64]

Table 3-50 shows the mark-up component of the real-time load-weighted LMP by fuel type and unit type using unadjusted and adjusted offers. The adjusted markup component of LMP increased from $1.13 per MWh in the first three months of 2016 to $3.81 per MWh in the first three months of 2017. The adjusted markup contribution of coal units in the first three months of 2017 was $1.23 per MWh. The mark-up component of gas-fired units in the first three months of 2017 was $2.31 per MWh, an increase of $0.68 per MWh from the first three months of 2016. The markup component of wind units was $0.19 per MWh. If a price-based offer is negative, but less negative than a cost-based offer, the markup is positive. In the first three months of 2017, among the wind units that were marginal, 15.9 percent had positive offer prices.

64 See PJM. "Manual 15: Cost Development Guidelines," Revision 27 (April 20, 2016).

Table 3-50 Markup component of the overall PJM real-time, load-weighted, average LMP by primary fuel type and unit type: January 1 through March 31, 2016 and 2017[65]

		2016 (Jan-Mar)		2017 (Jan-Mar)	
Fuel Type	Unit Type	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)
Coal	Steam	($2.21)	($0.50)	$0.11	$1.23
Gas	CC	$0.83	$1.31	$0.89	$2.04
Gas	CT	$0.08	$0.11	$0.13	$0.25
Gas	Diesel	($0.00)	$0.00	($0.00)	$0.00
Gas	Steam	$0.17	$0.22	($0.01)	$0.03
Municipal Waste	Diesel	$0.00	$0.00	$0.00	$0.00
Oil	CC	($0.00)	$0.01	$0.00	$0.00
Oil	CT	$0.02	$0.06	$0.01	$0.04
Oil	Diesel	$0.00	$0.00	$0.00	$0.00
Oil	Steam	$0.00	$0.01	$0.00	$0.00
Other	Steam	($0.11)	($0.11)	$0.02	$0.02
Wind	Wind	$0.02	$0.02	$0.19	$0.19
Total		($1.21)	$1.13	$1.35	$3.81

Markup Component of Real-Time Price

Table 3-51 shows the markup component, calculated using unadjusted offers, of average prices and of average monthly on-peak and off-peak prices. Table 3-52 shows the markup component, calculated using adjusted offers, of average prices and of average monthly on-peak and off-peak prices. In the first three months of 2017, when using unadjusted cost offers, $1.35 per MWh of the PJM real-time load-weighted average LMP was attributable to markup. Using adjusted cost offers, $3.81 per MWh of the PJM real-time load-weighted average LMP was attributable to markup. In the first three months of 2017, the peak markup component was highest in January, $3.11 per MWh using unadjusted cost offers and $5.88 per MWh using adjusted cost offers. This corresponds to 9.04 percent and 17.13 percent of the real-time peak load-weighted average LMP in January.

65 The Unit Type Diesel refers to power generation using reciprocating internal combustion engines. Such Diesel units can use a variety of fuel types including diesel, natural gas, oil and gas from municipal waste.

Table 3-51 Monthly markup components of real-time load-weighted LMP (Unadjusted): January 1 through March 31, 2016 and 2017

	2016			2017		
	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component
Jan	($1.89)	($1.95)	($1.82)	$1.75	$0.47	$3.11
Feb	($0.43)	($0.59)	($0.28)	$1.13	$0.53	$1.70
Mar	($1.24)	($1.22)	($1.25)	$1.12	$1.70	$0.60
Total	($1.21)	($1.30)	($1.12)	$1.35	$0.89	$1.80

Table 3-52 Monthly markup components of real-time load-weighted LMP (Adjusted): January 1 through March 31, 2016 and 2017

	2016			2017		
	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component
Jan	$0.76	$0.44	$1.12	$4.43	$3.07	$5.88
Feb	$1.98	$1.55	$2.39	$3.33	$2.60	$4.03
Mar	$0.63	$0.49	$0.76	$3.58	$3.82	$3.37
Total	$1.13	$0.81	$1.43	$3.81	$3.17	$4.44

Hourly Markup Component of Real-Time Prices

Figure 3-37 shows the markup contribution to the hourly load-weighted LMP using unadjusted cost offers in the first three months of 2017 and 2016. Figure 3-38 shows the markup contribution to the hourly load-weighted LMP using adjusted cost offers in the first three months of 2017 and 2016.

Figure 3-37 Markup contribution to real-time hourly load-weighted LMP (Unadjusted): January 1 through March 31, 2016 and 2017

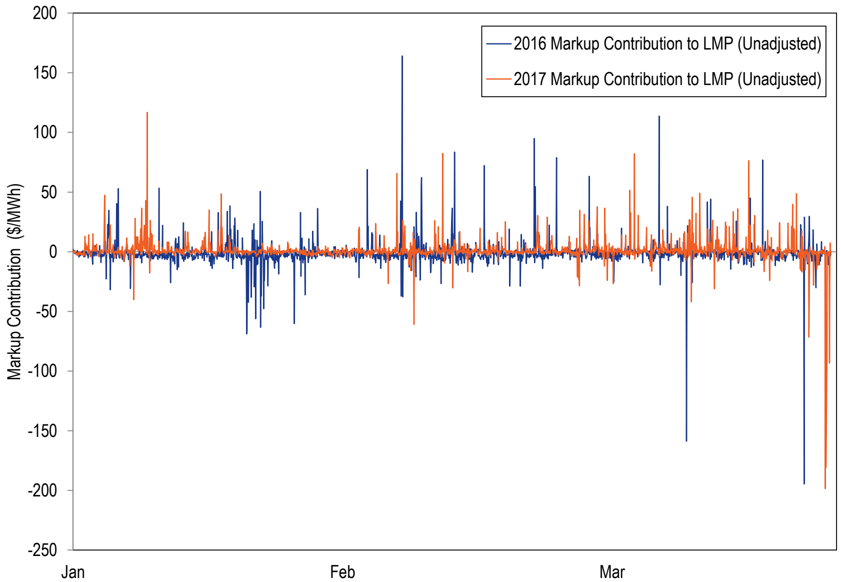


Figure 3-38 Markup contribution to real-time hourly load-weighted LMP (Adjusted): January 1 through March 31, 2016 and 2017

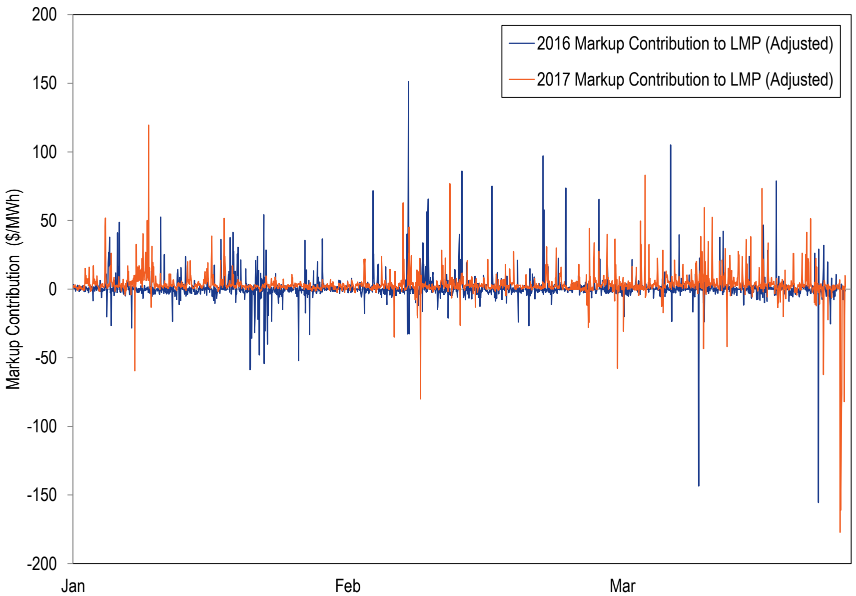


Table 3-53 Average real-time zonal markup component (Unadjusted): January 1 through March 31, 2016 and 2017

	2016 (Jan-Mar)			2017(Jan-Mar)		
	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component
AECO	($0.34)	($0.59)	($0.08)	$1.16	$0.65	$1.68
AEP	($1.43)	($1.52)	($1.34)	$1.23	$0.83	$1.62
APS	($1.52)	($1.65)	($1.39)	$1.38	$0.97	$1.80
ATSI	($1.68)	($1.77)	($1.60)	$1.32	$0.80	$1.80
BGE	($2.11)	($2.47)	($1.74)	$2.34	$1.47	$3.23
ComEd	($1.19)	($1.34)	($1.05)	$1.08	$0.77	$1.37
DAY	($1.88)	($1.74)	($2.02)	$1.35	$0.88	$1.79
DEOK	($1.52)	($1.65)	($1.39)	$1.18	$0.83	$1.52
DLCO	($1.60)	($1.73)	($1.47)	$1.22	$0.77	$1.65
DPL	($0.12)	($0.34)	$0.11	$1.48	$1.24	$1.74
Dominion	($1.59)	($1.67)	($1.51)	$1.79	$1.11	$2.49
EKPC	($1.39)	($1.17)	($1.62)	$1.27	$0.88	$1.68
JCPL	($0.35)	($0.17)	($0.53)	$0.99	$0.59	$1.38
Met-Ed	($0.23)	($0.28)	($0.18)	$0.90	$0.38	$1.40
PECO	($0.09)	($0.17)	($0.01)	$1.21	$0.85	$1.55
PENELEC	($1.01)	($1.11)	($0.91)	$1.37	$1.30	$1.43
PPL	($0.14)	($0.33)	$0.05	$1.00	$0.43	$1.56
PSEG	($0.48)	($0.14)	($0.80)	$1.10	$0.82	$1.36
Pepco	($1.85)	($2.12)	($1.58)	$2.09	$1.19	$2.97
RECO	($0.55)	($0.52)	($0.58)	$0.98	$1.40	$0.60

Markup Component of Real-Time Zonal Prices

The unit markup component of average real-time price using unadjusted offers is shown for each zone in the first three months of 2016 and 2017 in Table 3-53 and for adjusted offers in Table 3-54. The smallest zonal all hours average markup component using unadjusted offers in the first three months of 2017 was in the Met-Ed Zone, $0.90 per MWh, while the highest was in the BGE Control Zone, $2.34 per MWh. The smallest zonal on peak average markup was in the RECO Control Zone, $0.60 per MWh, while the highest was in the BGE Control Zone, $3.23 per MWh.

Table 3-54 Average real-time zonal markup component (Adjusted): January 1 through March 31, 2016 and 2017

	2016 (Jan-Mar)			2017 (Jan-Mar)		
	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component
AECO	$1.73	$1.31	$2.15	$3.69	$2.94	$4.44
AEP	$0.92	$0.63	$1.22	$3.60	$3.07	$4.12
APS	$0.93	$0.56	$1.29	$3.84	$3.26	$4.41
ATSI	$0.64	$0.33	$0.93	$3.83	$3.14	$4.49
BGE	$1.05	$0.43	$1.69	$4.90	$3.76	$6.04
ComEd	$0.94	$0.49	$1.36	$3.34	$2.93	$3.72
DAY	$0.46	$0.39	$0.54	$3.81	$3.18	$4.40
DEOK	$0.75	$0.41	$1.09	$3.50	$3.03	$3.95
DLCO	$0.68	$0.34	$1.01	$3.63	$3.04	$4.21
DPL	$2.25	$1.87	$2.64	$4.38	$4.06	$4.72
Dominion	$1.19	$0.87	$1.52	$4.25	$3.44	$5.09
EKPC	$0.93	$0.94	$0.91	$3.59	$3.10	$4.12
JCPL	$1.58	$1.56	$1.60	$3.65	$2.84	$4.41
Met-Ed	$1.70	$1.43	$1.95	$3.48	$2.59	$4.33
PECO	$1.79	$1.53	$2.04	$3.74	$3.14	$4.31
PENELEC	$1.19	$0.87	$1.49	$3.83	$3.60	$4.04
PPL	$1.79	$1.42	$2.16	$3.60	$2.75	$4.42
PSEG	$1.48	$1.58	$1.39	$3.74	$3.06	$4.38
Pepco	$1.05	$0.52	$1.58	$4.57	$3.45	$5.65
RECO	$1.40	$1.17	$1.61	$3.60	$3.71	$3.50

Markup by Real Time Price Levels

Table 3-55 shows the average markup component of LMP, based on the unadjusted cost-based offers and adjusted cost-based offers of the marginal units, when the PJM average LMP was in the identified price range.

Table 3-55 Average real-time markup component (By price category, unadjusted): January 1 through March 31, 2016 and 2017

	2016 (Jan-Mar)		2017 (Jan-Mar)	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $25	($1.26)	100.0%	($0.60)	44.9%
$25 to $50	$0.00	0.0%	$0.93	49.2%
$50 to $75	$0.00	0.0%	$0.64	4.4%
$75 to $100	$0.00	0.0%	$0.29	1.1%
$100 to $125	$0.00	0.0%	$0.04	0.1%
$125 to $150	$0.00	0.0%	$0.00	0.1%
>= $150	$0.00	0.0%	$0.07	0.1%

Table 3-56 Average real-time markup component (By price category, adjusted): January 1 through March 31, 2016 and 2017

	2016 (Jan-Mar)		2017 (Jan-Mar)	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $25	$1.17	100.0%	$0.28	45.0%
$25 to $50	$0.00	0.0%	$2.29	49.2%
$50 to $75	$0.00	0.0%	$0.82	4.4%
$75 to $100	$0.00	0.0%	$0.35	1.1%
$100 to $125	$0.00	0.0%	$0.04	0.1%
$125 to $150	$0.00	0.0%	($0.00)	0.1%
>= $150	$0.00	0.0%	$0.07	0.1%

Day-Ahead Markup

Markup Component of Day-Ahead Price by Fuel, Unit Type

The markup component of the PJM day-ahead, load-weighted average LMP by primary fuel and unit type is shown in Table 3-57. INC, DEC and up to congestion transactions have zero markups. INCs were 4.6 percent of marginal resources and DECs were 7.6 percent of marginal resources in the first three months of 2017. The share of marginal up to congestion transactions decreased significantly beginning on September 8, 2014, as a result of the FERC's UTC uplift refund notice which became effective on September 8, 2014.[66] However, the share of marginal up to congestion transactions increased from 83.2 percent in the first three months of 2016 to 83.7 percent in the first three

66 See 18 CFR § 385.213 (2014).

months of 2017 due to the expiration of the fifteen months resettlement period for the proceeding related to uplift charges for UTC transactions. The adjusted markup of coal, gas and oil units is calculated as the difference between the price offer, and the cost offer excluding the 10 percent adder. Table 3-57 shows the markup component of LMP for marginal generating resources. Generating resources were only 4.1 percent of marginal resources in the first three months of 2017. Using adjusted offers, the markup component of LMP for marginal generating resources increased for coal-fired steam units from a negative markup to a positive markup and for gas-fired CT units from $0.02 to $0.04. The markup component of LMP for coal-fired steam units increased from -$1.95 in the first three months of 2016 to -$0.13 in the first three months of 2017 using unadjusted offers. The markup component of LMP for gas-fired steam units decreased from $0.43 in the first three months of 2016 to $0.31 in the first three months of 2017 using unadjusted offers.

Table 3-57 Markup component of the annual PJM day-ahead, load-weighted, average LMP by primary fuel type and unit type: January 1 through March 31, 2016 and 2017

		2016 (Jan - Mar)		2017 (Jan - Mar)	
Fuel Type	Unit Type	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)
Coal	Steam	($1.95)	($0.70)	($0.13)	$0.58
Gas	CT	($0.01)	$0.02	($0.00)	$0.04
Gas	Diesel	$0.00	$0.00	$0.00	$0.00
Gas	Steam	$0.43	$0.77	$0.31	$0.91
Oil	CT	$0.00	$0.00	($0.00)	$0.00
Oil	Diesel	$0.00	$0.00	$0.00	($0.00)
Oil	Steam	$0.00	$0.00	$0.00	$0.00
Other	Steam	($0.11)	($0.11)	$0.01	$0.01
Wind	Wind	$0.02	$0.02	$0.01	$0.01
Total		($1.63)	$0.00	$0.20	$1.56

Markup Component of Day-Ahead Price

The markup component of price is the difference between the system price, when the system price is determined by the active offers of the marginal units, whether price or cost-based, and the system price, based on the cost-based offers of those marginal units. Only hours when generating units were marginal on either priced-based offers or on cost-based offers were included in the markup calculation.

Table 3-58 shows the markup component of average prices and of average monthly on-peak and off-peak prices using unadjusted offers. In the first three months of 2017, when using unadjusted cost-based offers, $0.20 per MWh of the PJM day-ahead load-weighted average LMP was attributable to markup. In the first three months of 2017, the peak markup component was highest in March, $0.83 per MWh using unadjusted cost offers.

Table 3-58 Monthly markup components of day-ahead (Unadjusted), load-weighted LMP: January 1 through March 31, 2016 and 2017

	2016			2017		
	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
Jan	($2.04)	($1.71)	($2.33)	($0.03)	$0.19	($0.23)
Feb	($1.15)	($1.32)	($0.96)	$0.25	$0.59	($0.10)
Mar	($1.66)	($1.26)	($2.12)	$0.38	$0.83	($0.12)
Apr	($0.37)	$0.76	($1.54)			
May	($0.71)	($0.16)	($1.26)			
Jun	$0.19	$0.74	($0.48)			
Jul	($3.73)	($6.42)	($1.05)			
Aug	($0.05)	$0.08	($0.22)			
Sep	($0.99)	($0.57)	($1.47)			
Oct	$0.65	$1.75	($0.45)			
Nov	$0.08	$0.52	($0.37)			
Dec	$0.30	$0.89	($0.27)			
Annual	($1.63)	($1.43)	($1.83)	$0.20	$0.54	($0.15)

Table 3-59 shows the markup component of average prices and of average monthly on-peak and off-peak prices using adjusted offers. In the first three months of 2017, when using adjusted cost-based offers, $1.56 per MWh of the PJM day-ahead load-weighted average LMP was attributable to markup. In the first three months of 2017, the peak markup component was highest in March, $1.99 per MWh using adjusted cost offers.

Table 3-59 Monthly markup components of day-ahead (Adjusted), load-weighted LMP: January 1 2016 through March 31, 2017

	2016			2017		
	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
Jan	($0.17)	$0.19	($0.48)	$1.40	$1.49	$1.32
Feb	$0.44	$0.27	$0.62	$1.65	$1.89	$1.39
Mar	($0.26)	$0.14	($0.72)	$1.65	$1.99	$1.27
Apr	$0.92	$1.86	($0.05)			
May	$0.60	$1.10	$0.09			
Jun	$1.58	$2.16	$0.89			
Jul	($2.90)	($6.38)	$0.58			
Aug	$3.94	$6.08	$1.27			
Sep	$0.17	$0.17	$0.16			
Oct	$1.69	$2.46	$0.91			
Nov	$1.25	$1.51	$0.99			
Dec	$1.82	$2.14	$1.50			
Annual	$0.00	$0.20	($0.20)	$1.56	$1.79	$1.33

Markup Component of Day-Ahead Zonal Prices

The markup component of annual average day-ahead price using unadjusted offers is shown for each zone in Table 3-60. The markup component of annual average day-ahead price using adjusted offers is shown for each zone in Table 3-61. Using unadjusted offers, the markup component of the average day-ahead price increased in all zones from the first three months of 2016 to the first three months of 2017. The smallest zonal all hours average markup component using adjusted offers for the first three months of 2017 was in the Pepco Zone, $1.38 per MWh, while the highest was in the DPL Control Zone, $2.15 per MWh. The smallest zonal on peak average markup using adjusted offers was in the ComEd Control Zone, $1.61 per MWh, while the highest was in the DPL Control Zone, $2.54 per MWh.

Table 3-60 Day-ahead, average, zonal markup component (Unadjusted): January 1 through March 31, 2016 and 2017

	2016 (Jan - Mar)			2017 (Jan - Mar)		
	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
AECO	($0.52)	($0.35)	($0.70)	$0.63	$1.13	$0.11
AEP	($1.79)	($1.61)	($1.97)	$0.10	$0.42	($0.22)
AP	($1.89)	($1.70)	($2.07)	$0.13	$0.45	($0.20)
ATSI	($1.83)	($1.61)	($2.06)	$0.13	$0.44	($0.21)
BGE	($2.44)	($2.44)	($2.44)	($0.03)	$0.32	($0.40)
ComEd	($1.73)	($1.56)	($1.91)	$0.09	$0.39	($0.22)
DAY	($1.92)	($1.71)	($2.15)	$0.13	$0.44	($0.20)
DEOK	($1.84)	($1.64)	($2.04)	$0.13	$0.43	($0.19)
DLCO	($1.80)	($1.60)	($2.01)	$0.13	$0.46	($0.22)
Dominion	($2.14)	($2.07)	($2.21)	$0.02	$0.38	($0.32)
DPL	($0.82)	($0.54)	($1.09)	$0.65	$1.15	$0.15
EKPC	($1.78)	($1.53)	($2.02)	$0.11	$0.43	($0.19)
JCPL	($0.74)	($0.54)	($0.95)	$0.47	$0.81	$0.11
Met-Ed	($0.86)	($0.70)	($1.04)	$0.49	$0.84	$0.13
PECO	($0.68)	($0.36)	($1.01)	$0.64	$1.10	$0.17
PENELEC	($1.44)	($1.16)	($1.72)	$0.27	$0.60	($0.08)
Pepco	($2.30)	($2.22)	($2.38)	($0.04)	$0.29	($0.37)
PPL	($0.80)	($0.59)	($1.02)	$0.51	$0.89	$0.12
PSEG	($0.77)	($0.26)	($1.32)	$0.41	$0.75	$0.05
RECO	($0.77)	($0.42)	($1.16)	$0.43	$0.73	$0.11

Table 3-61 Day-ahead, average, zonal markup component (Adjusted): January 1 through March 31, 2016 and 2017

	2016 (Jan - Mar)			2017 (Jan - Mar)		
	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
AECO	$0.95	$1.17	$0.73	$2.02	$2.37	$1.65
AEP	($0.13)	$0.02	($0.28)	$1.46	$1.67	$1.25
AP	($0.20)	($0.03)	($0.38)	$1.50	$1.72	$1.28
ATSI	($0.15)	$0.04	($0.35)	$1.52	$1.72	$1.29
BGE	($0.81)	($0.77)	($0.84)	$1.39	$1.67	$1.11
ComEd	($0.16)	$0.00	($0.34)	$1.41	$1.61	$1.20
DAY	($0.21)	($0.01)	($0.41)	$1.50	$1.71	$1.28
DEOK	($0.17)	$0.02	($0.36)	$1.45	$1.66	$1.24
DLCO	($0.15)	$0.04	($0.34)	$1.49	$1.71	$1.25
Dominion	($0.45)	($0.35)	($0.55)	$1.43	$1.68	$1.18
DPL	$0.92	$1.21	$0.64	$2.15	$2.54	$1.76
EKPC	($0.15)	$0.04	($0.32)	$1.44	$1.64	$1.24
JCPL	$0.84	$1.06	$0.60	$1.83	$2.01	$1.64
Met-Ed	$0.70	$0.89	$0.49	$1.85	$2.05	$1.64
PECO	$0.88	$1.21	$0.54	$2.04	$2.35	$1.71
PENELEC	$0.20	$0.47	($0.07)	$1.60	$1.83	$1.35
Pepco	($0.62)	($0.52)	($0.72)	$1.38	$1.62	$1.13
PPL	$0.76	$0.99	$0.52	$1.87	$2.09	$1.64
PSEG	$0.76	$1.30	$0.19	$1.78	$1.96	$1.59
RECO	$0.69	$1.09	$0.26	$1.78	$1.93	$1.62

Markup by Day-Ahead Price Levels

Table 3-62 and Table 3-63 show the average markup component of LMP, based on the unadjusted cost-based offers and adjusted cost-based offers of the marginal units, when the PJM system LMP was in the identified price range.

Table 3-62 Average, day-ahead markup (By LMP category, unadjusted): January 1 through March 31, 2016 and 2017

	2016 (Jan - Mar)		2017 (Jan - Mar)	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $25	($2.20)	50.2%	($0.66)	37.2%
$25 to $50	($1.81)	47.4%	$0.63	60.3%
$50 to $75	$4.38	2.3%	$1.08	2.1%
$75 to $100	$6.46	0.1%	$0.86	0.3%

Table 3-63 Average, day-ahead markup (By LMP category, adjusted): January 1 through March 31, 2016 and 2017

	2016 (Jan - Mar)		2017 (Jan - Mar)	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $25	($0.53)	50.2%	$1.07	37.2%
$25 to $50	$0.08	47.4%	$2.20	60.3%
$50 to $75	$5.88	2.3%	$2.79	2.1%
$75 to $100	$6.88	0.1%	$1.12	0.3%

Prices

The conduct of individual market entities within a market structure is reflected in market prices. PJM locational marginal prices (LMPs) are a direct measure of market performance. Price level is a good, general indicator of market performance, although overall price results must be interpreted carefully because of the multiple factors that affect them. Among other things, overall average prices reflect changes in supply and demand, generation fuel mix, the cost of fuel, emission related expenses, markup and local price differences caused by congestion. PJM also may administratively set prices with the creation of a closed loop interface related to demand side resources or reactive power.

Real-time and day-ahead energy market load-weighted prices were 13.0 percent and 8.8 percent higher in the first three months of 2017 than in the first three months of 2016.

PJM real-time energy market prices increased in the first three months of 2017 compared to the first three months of 2016. The average LMP was 14.8 percent higher in the first three months of 2017 than in the first three months of 2016, $29.39 per MWh versus $25.60 per MWh. The load-weighted average LMP was 13.0 percent higher in the first three months of 2017 than in the first three months of 2016, $30.28 per MWh versus $26.80 per MWh.

The fuel-cost adjusted, load-weighted, average LMP in the first three months of 2017 was 22.9 percent lower than the load-weighted, average LMP for the first three months of 2016. If fuel and emission costs in the first three months of 2017 had been the same as in the first three months of 2016, holding everything else constant, the load-weighted LMP would have been lower, $23.35 per MWh instead of the observed $30.28 per MWh.

PJM day-ahead energy market prices increased in the first three months of 2017 compared to the first three months of 2016. The day-ahead average LMP was 10.0 percent higher in the first three months of 2017 than in the first three months of 2016, $29.59 per MWh versus $26.90 per MWh. The day-ahead load-weighted average LMP was 8.8 percent higher in the first three months of 2017 than in the first three months of 2016, $30.40 per MWh versus $27.94 per MWh.

Occasionally, in a constrained market, the LMPs at some pricing nodes can exceed the offer price of the highest cleared generator in the supply stack.[67] In the nodal pricing system, the LMP at a pricing node is the total cost of meeting incremental demand at that node. When there are binding transmission constraints, satisfying the marginal increase in demand at a node may require increasing the output of some generators while simultaneously decreasing the output of other generators, such that the transmission constraints are not violated. The total cost of redispatching multiple generators can at times exceed the cost of marginally increasing the output of the most expensive generator offered. Thus the LMPs at some pricing nodes exceed $1,000 per MWh, the cap on the generators' offer price in the PJM market.[68]

67 See O'Neill R. P, Mead D. and Malvadkar P. "On Market Clearing Prices Higher than the Highest Bid and Other Almost Paranormal Phenomena." *The Electricity Journal* 2005; 18(2): pp 19-27.

68 The offer cap in PJM was temporarily increased to $1,800 per MWh prior to the winter of 2014/2015. A new cap of $2,000 per MWh, only for offers with costs exceeding $1,000 per MWh, went into effect on December, 14, 2015, 153 FERC ¶ 61,289 (2015).

Real-Time LMP

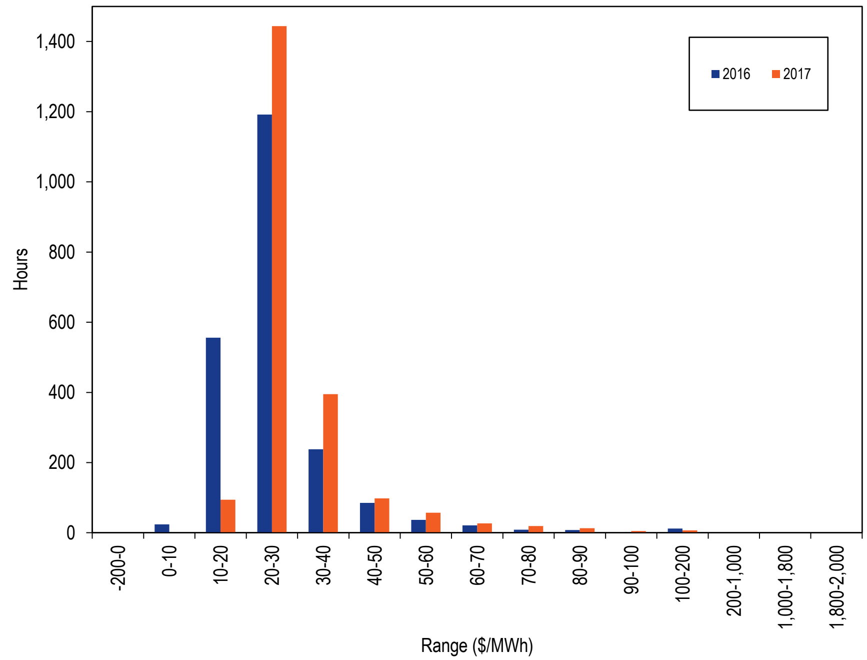
Real-time average LMP is the hourly average LMP for the PJM Real-Time Energy Market.[69]

Real-Time Average LMP

PJM Real-Time Average LMP Duration

Figure 3-39 shows the hourly distribution of PJM real-time average LMP for the first three months of 2016 and 2017.

Figure 3-39 Average LMP for the PJM Real-Time Energy Market: January 1 through March 31, 2016 and 2017



69 See the *MMU Technical Reference for the PJM Markets*, at "Calculating Locational Marginal Price," for detailed definition of Real-Time LMP. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

PJM Real-Time, Average LMP

Table 3-64 shows the PJM real-time, average LMP for the first three months of each year from 1998 through 2017.[70]

Table 3-64 PJM real-time, average LMP (Dollars per MWh): January 1 through March 31, 1998 through 2017

	Real-Time LMP			Year-to-Year Change		
Jan-Mar	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$17.51	$15.30	$7.84	NA	NA	NA
1999	$18.79	$16.56	$7.29	7.3%	8.3%	(7.0%)
2000	$23.66	$17.73	$16.22	25.9%	7.0%	122.4%
2001	$33.77	$26.01	$20.79	42.8%	46.8%	28.2%
2002	$22.23	$19.22	$9.61	(34.2%)	(26.1%)	(53.8%)
2003	$49.57	$43.08	$30.54	123.0%	124.2%	217.9%
2004	$46.37	$41.04	$24.07	(6.5%)	(4.8%)	(21.2%)
2005	$46.51	$40.62	$22.07	0.3%	(1.0%)	(8.3%)
2006	$52.98	$46.15	$23.29	13.9%	13.6%	5.5%
2007	$55.34	$47.15	$33.29	4.5%	2.2%	43.0%
2008	$66.75	$57.05	$35.54	20.6%	21.0%	6.8%
2009	$47.29	$40.56	$21.99	(29.2%)	(28.9%)	(38.1%)
2010	$44.13	$37.82	$21.87	(6.7%)	(6.8%)	(0.6%)
2011	$44.76	$38.14	$23.10	1.4%	0.8%	5.6%
2012	$30.38	$28.82	$11.63	(32.1%)	(24.4%)	(49.7%)
2013	$36.33	$32.29	$18.47	19.6%	12.1%	58.9%
2014	$84.04	$48.77	$119.84	131.3%	51.0%	548.8%
2015	$47.39	$31.95	$42.42	(43.6%)	(34.5%)	(64.6%)
2016	$25.60	$22.91	$12.99	(46.0%)	(28.3%)	(69.4%)
2017	$29.39	$25.71	$12.28	14.8%	12.2%	(5.4%)

Real-Time, Load-Weighted, Average LMP

Higher demand (load) generally results in higher prices, all else constant. As a result, load-weighted, average prices are generally higher than average prices. Load-weighted LMP reflects the average LMP paid for actual MWh consumed during a year. Load-weighted, average LMP is the average of PJM hourly LMP, each weighted by the PJM total hourly load.

PJM Real-Time, Load-Weighted, Average LMP

Table 3-65 shows the PJM real-time, load-weighted, average LMP in the first three months of 1998 through 2017.

Table 3-65 PJM real-time, load-weighted, average LMP (Dollars per MWh): January 1 through March 31, 1998 through 2017

	Real-Time, Load-Weighted, Average LMP			Year-to-Year Change		
Jan-Mar	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$18.13	$15.80	$8.14	NA	NA	NA
1999	$19.38	$16.90	$7.66	6.9%	7.0%	(5.9%)
2000	$25.10	$18.25	$17.22	29.5%	8.0%	124.9%
2001	$35.16	$27.38	$21.52	40.1%	50.0%	25.0%
2002	$23.01	$19.89	$9.93	(34.6%)	(27.4%)	(53.8%)
2003	$51.93	$46.12	$30.99	125.6%	131.9%	211.9%
2004	$48.77	$43.22	$24.62	(6.1%)	(6.3%)	(20.6%)
2005	$48.37	$42.20	$22.62	(0.8%)	(2.4%)	(8.1%)
2006	$54.43	$47.62	$23.69	12.5%	12.9%	4.7%
2007	$58.07	$50.60	$34.44	6.7%	6.3%	45.4%
2008	$69.35	$60.11	$36.56	19.4%	18.8%	6.2%
2009	$49.60	$42.23	$23.38	(28.5%)	(29.8%)	(36.1%)
2010	$45.92	$39.01	$22.99	(7.4%)	(7.6%)	(1.7%)
2011	$46.35	$39.11	$24.26	0.9%	0.3%	5.5%
2012	$31.21	$29.25	$12.02	(32.7%)	(25.2%)	(50.5%)
2013	$37.41	$32.79	$19.90	19.9%	12.1%	65.7%
2014	$92.98	$51.62	$134.40	148.5%	57.4%	575.3%
2015	$50.91	$33.51	$46.43	(45.2%)	(35.1%)	(65.5%)
2016	$26.80	$23.45	$13.98	(47.4%)	(30.0%)	(69.9%)
2017	$30.28	$26.26	$13.08	13.0%	12.0%	(6.4%)

Table 3-66 shows zonal real-time, and real-time, load-weighted, average LMP in the first three months of 2016 and 2017.

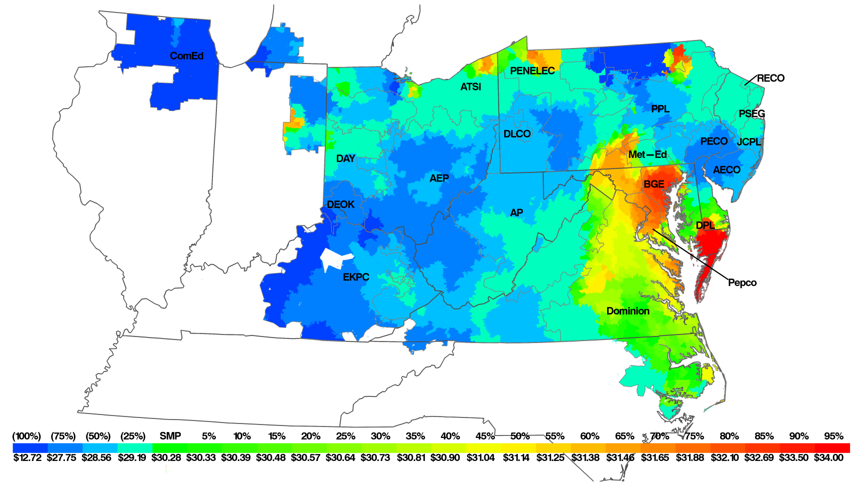
70 The system average LMP is the average of the hourly LMP without any weighting. The only exception is that market-clearing prices (MCPs) are included for January to April 1998. MCP was the single market-clearing price calculated by PJM prior to implementation of LMP.

Table 3-66 Zone real-time and real-time, load-weighted, average LMP (Dollars per MWh): January 1 through March 31, 2016 and 2017

	Real-Time Average LMP			Real-Time, Load-Weighted, Average LMP		
Zone	2016 (Jan-Mar)	2017 (Jan-Mar)	Percent Change	2016 (Jan-Mar)	2017 (Jan-Mar)	Percent Change
AECO	$24.13	$28.48	18.0%	$25.73	$29.59	15.0%
AEP	$25.46	$28.70	12.7%	$26.49	$29.39	10.9%
AP	$26.36	$29.68	12.6%	$27.63	$30.63	10.9%
ATSI	$25.28	$29.81	17.9%	$26.03	$30.45	17.0%
BGE	$33.96	$33.15	(2.4%)	$36.11	$34.79	(3.6%)
ComEd	$22.80	$26.52	16.3%	$23.45	$26.95	14.9%
Day	$25.19	$29.20	15.9%	$26.08	$29.88	14.6%
DEOK	$24.52	$27.94	13.9%	$25.42	$28.57	12.4%
DLCO	$24.92	$29.03	16.5%	$25.68	$29.67	15.5%
Dominion	$29.09	$30.88	6.1%	$31.29	$32.58	4.1%
DPL	$28.02	$31.16	11.2%	$30.56	$33.13	8.4%
EKPC	$24.56	$27.79	13.2%	$25.78	$28.75	11.5%
JCPL	$22.39	$29.45	31.5%	$23.79	$30.63	28.8%
Met-Ed	$22.32	$29.37	31.6%	$23.63	$30.41	28.7%
PECO	$21.94	$28.53	30.0%	$23.29	$29.58	27.0%
PENELEC	$24.34	$29.07	19.4%	$25.29	$29.79	17.8%
Pepco	$30.50	$31.76	4.1%	$32.38	$33.26	2.7%
PPL	$22.46	$29.22	30.1%	$23.88	$30.35	27.1%
PSEG	$22.77	$29.61	30.0%	$23.95	$30.51	27.4%
RECO	$22.61	$29.84	32.0%	$23.79	$30.77	29.4%
PJM	$25.60	$29.39	14.8%	$26.80	$30.28	13.0%

Figure 3-40 is a contour map of the real-time, load-weighted, average LMP in the first three months of 2017. In the legend, green represents the system marginal price (SMP) and each increment to the right and left of the SMP represents five percent of the pricing nodes above and below the SMP. The LMP for each five percent increment is the highest nodal average LMP for that set of nodes. Each increment to the left of the SMP is the lowest nodal average LMP for that set of nodes.

Figure 3-40 PJM real-time, load-weighted, average LMP: January 1 through March 31, 2017



PJM Real-Time, Monthly, Load-Weighted, Average LMP

Figure 3-41 shows the PJM real-time monthly and annual load-weighted LMP in 1999 through the first three months of 2017. PJM real-time monthly load-weighted average LMP in March 2016 was $22.90, which is the lowest real-time monthly load-weighted average LMP since February 2002 at $21.39.

Figure 3-41 PJM real-time, monthly and annual, load-weighted, average LMP:January 1, 1999 through March 31, 2017

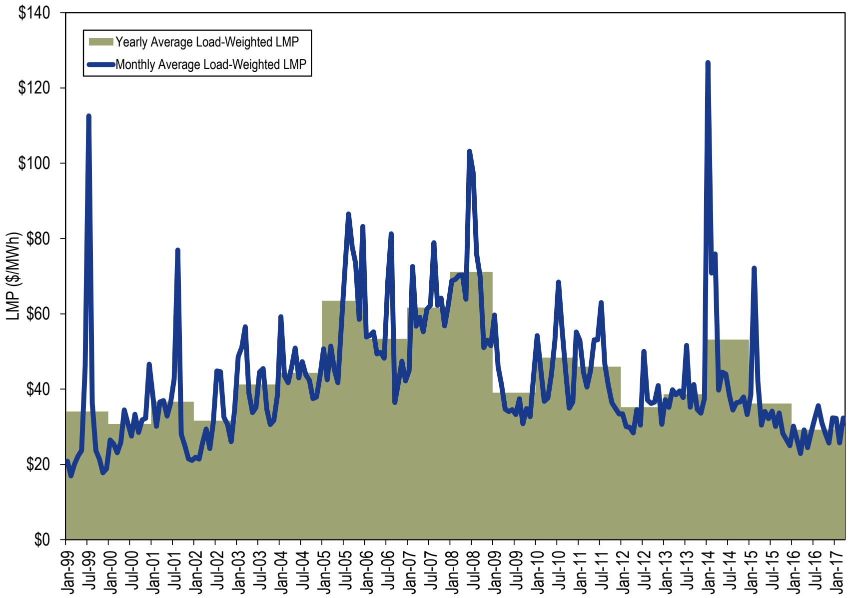
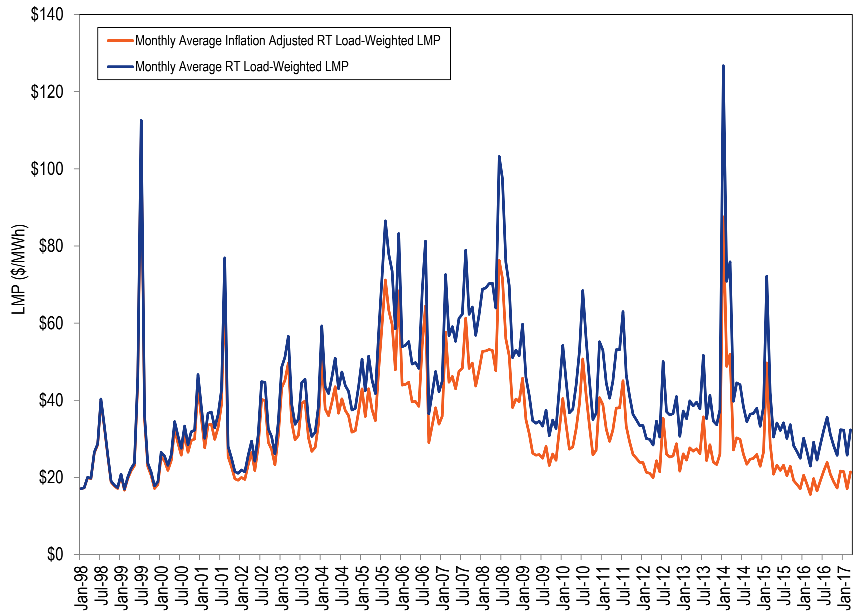


Figure 3-42 PJM real-time, monthly, load-weighted, average LMP and real-time, monthly inflation adjusted load-weighted, average LMP: January 1, 1998 through March 31, 2017



PJM Real-Time, Monthly, Inflation Adjusted Load-Weighted, Average LMP

Figure 3-42 shows the PJM real-time monthly load-weighted average LMP and inflation adjusted monthly load-weighted average LMP for January 1, 1998, through March 31, 2017.[71] Table 3-67 shows the PJM real-time yearly load-weighted average LMP and inflation adjusted yearly load-weighted average LMP for the first three months of every year starting from 1998 through 2017.

71 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> (April22, 2017)

Table 3-67 PJM real-time, yearly, load-weighted, average LMP and real-time, yearly inflation adjusted load-weighted, average LMP: January 1 through March 31, 1998 through 2017

Year (Jan-Mar)	Load-Weighted, Average LMP	Inflation Adjusted Load-Weighted, Average LMP
1998	$18.13	$18.10
1999	$19.38	$19.03
2000	$25.10	$23.89
2001	$35.16	$32.35
2002	$23.01	$20.90
2003	$51.93	$45.86
2004	$48.77	$42.36
2005	$48.37	$40.73
2006	$54.43	$44.21
2007	$58.07	$46.05
2008	$69.35	$52.85
2009	$49.60	$37.83
2010	$45.92	$34.21
2011	$46.35	$33.83
2012	$31.21	$22.14
2013	$37.41	$26.09
2014	$92.98	$64.01
2015	$50.91	$35.04
2016	$26.80	$18.25
2017	$30.28	$20.11

Fuel Price Trends and LMP

Changes in LMP can result from changes in the marginal costs of marginal units, the units setting LMP. In general, fuel costs make up between 80 percent and 90 percent of marginal cost depending on generating technology, unit efficiency, unit age and other factors. The impact of fuel cost on marginal cost and on LMP depends on the fuel burned by marginal units and changes in fuel costs. Changes in emission allowance costs are another contributor to changes in the marginal cost of marginal units. Natural gas prices and coal prices increased in the first three months of 2017 compared to the first three months of 2016. The price of Northern Appalachian coal was 30.1 percent higher; the price of Central Appalachian coal was 34.6 percent higher; the price of Powder River Basin coal was 17.1 percent higher; the price of eastern natural gas was 36.0 percent higher; and the price of western natural gas was 64.6 percent higher. Figure 3-43 shows monthly average spot fuel prices.[72]

Figure 3-43 Spot average fuel price comparison with fuel delivery charges: January 1, 2012 through March 31, 2017 ($/MMBtu)

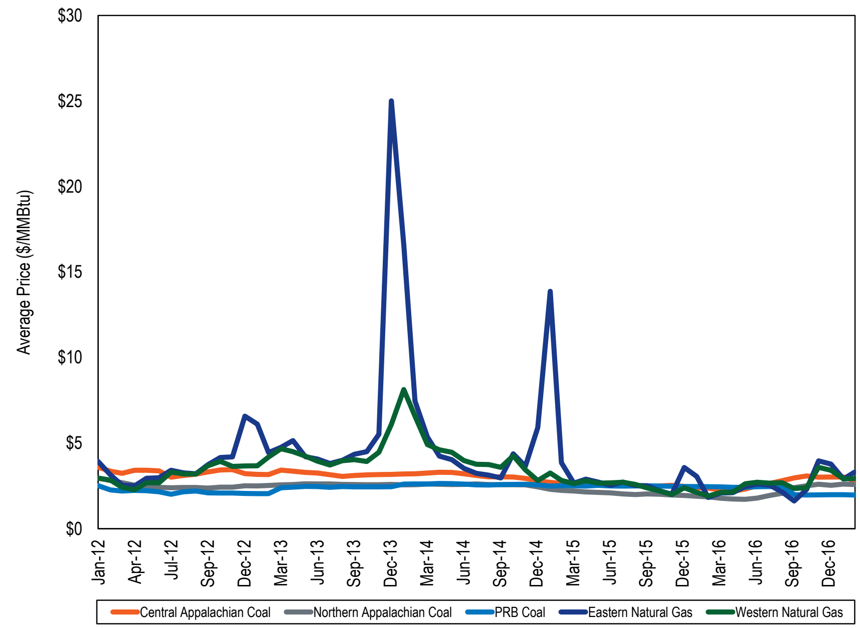


Table 3-68 compares the 2017 PJM real-time fuel-cost adjusted, load-weighted, average LMP to 2017 load-weighted, average LMP.[73] The real-time fuel-cost adjusted, load-weighted, average LMP for the first three months of 2017 was 22.9 percent lower than the real-time load-weighted, average LMP for the first three months of 2017. The real-time, fuel-cost adjusted, load-weighted, average LMP for the first three months of 2017 was 12.9 percent lower than the real-time load-weighted LMP for the first three months of 2016. If fuel

72 Eastern natural gas consists of the average of Texas M3, Transco Zone 6 non-NY, Transco Zone 6 NY and Transco Zone 5 daily fuel price indices. Western natural gas prices are the average of Dominion North Point, Columbia Appalachia and Chicago Citygate daily fuel price indices. Coal prices are the average of daily fuel prices for Central Appalachian coal, Northern Appalachian coal, and Powder River Basin coal. All fuel prices are from Platts.

73 The fuel-cost adjusted LMP reflects both the fuel and emissions where applicable, including NO_x, CO_2 and SO_x costs.

and emissions costs in the first three months of 2017 had been the same as in the first three months of 2016, holding everything else constant, the real-time load-weighted LMP in the first three months of 2017 would have been lower, \$23.25 per MWh, than the observed \$30.28 per MWh.

Table 3-68 PJM real-time annual, fuel-cost adjusted, load-weighted average LMP (Dollars per MWh): quarter over quarter

	2017 Load-Weighted LMP	2017 Fuel-Cost Adjusted, Load-Weighted LMP	Change
Average	\$30.28	\$23.35	(22.9%)
	2016 Load-Weighted LMP	2017 Fuel-Cost Adjusted, Load-Weighted LMP	Change
Average	\$26.80	\$23.35	(12.9%)
	2016 Load-Weighted LMP	2017 Load-Weighted LMP	Change
Average	\$26.80	\$30.28	13.0%

Table 3-69 shows the impact of each fuel type on the difference between the fuel-cost adjusted, load-weighted average LMP and the load-weighted LMP in the first three months of 2017. Table 3-69 shows that higher natural gas prices explains most of the fuel-cost related increase in the real-time annual load-weighted average LMP in the first three months of 2017.

Table 3-69 Change in PJM real-time annual, fuel-cost adjusted, load-weighted average LMP (Dollars per MWh) by fuel type: year over year

Fuel Type	Share of Change in Fuel Cost Adjusted, Load Weighted LMP	Percent
Coal	\$2.48	35.8%
Gas	\$4.27	61.6%
Municipal Waste	\$0.00	0.0%
Oil	\$0.17	2.4%
Other	\$0.00	0.0%
Uranium	(\$0.00)	-0.0%
Wind	(\$0.00)	-0.0%
Total	\$6.93	100.0%

Components of Real-Time, Load-Weighted LMP

LMPs result from the operation of a market based on security-constrained, economic (least-cost) dispatch (SCED) in which marginal units determine system LMPs, based on their offers and five minute ahead forecasts of system conditions. Those offers can be decomposed into components including fuel costs, emission costs, variable operation and maintenance costs, markup, FMU adder and the 10 percent cost adder. As a result, it is possible to decompose LMP by the components of unit offers.

Cost offers of marginal units are separated into their component parts. The fuel related component is based on unit specific heat rates and spot fuel prices. Emission costs are calculated using spot prices for NO_x, SO_2 and CO_2 emission credits, emission rates for NO_x, emission rates for SO_2 and emission rates for CO_2. The CO_2 emission costs are applicable to PJM units in the PJM states that participate in RGGI: Delaware and Maryland.[74] The FMU adder is the calculated contribution of the FMU and AU adders to LMP that results when units with FMU or AU adders are marginal.

Since the implementation of scarcity pricing on October 1, 2012, PJM jointly optimizes the commitment and dispatch of energy and ancillary services. In periods of scarcity when generators providing energy have to be dispatched down from their economic operating level to meet reserve requirements, the joint optimization of energy and reserves takes into account the opportunity cost of the reduced generation and the associated incremental cost to maintain reserves. If a unit incurring such opportunity costs is a marginal resource in the energy market, this opportunity cost will contribute to LMP. In addition, in periods when generators providing energy cannot meet the reserve requirements, PJM can invoke shortage pricing. PJM invoked shortage pricing on January 6 and January 7 of 2014.[75] During the shortage conditions, the LMPs of marginal generators reflect the cost of not meeting the reserve requirements, the scarcity adder, which is defined by the operating reserve demand curve.

LMP may, at times, be set by transmission penalty factors. When a transmission constraint is binding and there are no generation alternatives to resolve the constraint, system operators may allow the transmission limit to be violated. When this occurs, the shadow price of the constraint is set by transmission penalty factors. The shadow price directly affects the LMP. Transmission

74 New Jersey withdrew from RGGI, effective January 1, 2012.

75 PJM triggered shortage pricing on January 6, 2015, following a RTO-wide voltage reduction action. PJM triggered shortage pricing on January 7, 2014, due to a RTO-wide shortage of synchronized reserve.

penalty factors are administratively determined and can be thought of as a form of locational scarcity pricing.

Table 3-72 shows the frequency and average shadow price of transmission constraints in PJM. In the first three months of 2017, there were 45,165 transmission constraints in the real-time market with a non-zero shadow price. For nearly nine percent of these transmission constraints, the line limit was violated, meaning that the flow exceeded the facility limit.[76] In the first three months of 2017, the average shadow price of transmission constraints when the line limit was violated was nearly five times higher than when transmission constraint was binding at its limit.

Transmission penalty factors should be stated explicitly and publicly and applied without discretion. Penalty factors should be set high enough so that they do not act to suppress prices based on available generator solutions. But rather than permit the transmission penalty factor to set the shadow price when line limits are violated, PJM uses a procedure called constraint relaxation logic to prevent the penalty factors from directly setting the shadow price of the constraint. The result is that the transmission penalty factor does not directly set the shadow price. The details of PJM's logic and practice are not entirely clear. But in 2016, for all transmission constraints for which the penalty factor was greater than or equal to $2,000 per MWh, 41 percent of the constraints' shadow prices were within 10 percent of the penalty factor.

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.

The components of LMP are shown in Table 3-70, including markup using unadjusted cost offers.[77] Table 3-70 shows that in the first three months of 2017, 40.3 percent of the load-weighted LMP was the result of coal costs, 32.4 percent was the result of gas costs and 2.09 percent was the result of the cost of emission allowances. Using adjusted cost offers, markup was 12.6 percent of the load-weighted LMP. The fuel-related components of LMP reflect the degree to which the cost of the identified fuel affects LMP and does not reflect the other components of the offers of units burning that fuel. The component NA is the unexplained portion of load-weighted LMP. Occasionally, PJM fails to provide all the data needed to accurately calculate generator sensitivity factors. As a result, the LMP for those intervals cannot be decomposed into component costs. The cumulative effect of excluding those five-minute intervals is the component NA. In the first three months of 2017, nearly 14.4 percent of all five-minute intervals had insufficient data. The percent column is the difference in the proportion of LMP represented by each component between the first three months of 2017 and 2016.

76 The line limit of a facility associated with a transmission constraint is not necessarily the rated line limit. In PJM, the dispatcher has the discretion to lower the rated line limit.

77 These components are explained in the *Technical Reference for PJM Markets*, at p 27 "Calculation and Use of Generator Sensitivity/Unit Participation Factors." <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

Table 3-70 Components of PJM real-time (Unadjusted), load-weighted, average LMP: January 1 through March 31, 2016 and 2017

	2016 (Jan-Mar)		2017 (Jan-Mar)		Change
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Percent
Gas	$5.30	19.8%	$12.21	40.3%	20.6%
Coal	$14.78	55.1%	$9.81	32.4%	(22.7%)
Ten Percent Adder	$2.35	8.8%	$2.45	8.1%	(0.7%)
Markup	($1.21)	(4.5%)	$1.35	4.5%	9.0%
VOM	$2.04	7.6%	$1.34	4.4%	(3.2%)
Increase Generation Adder	$0.19	0.7%	$0.96	3.2%	2.5%
LPA Rounding Difference	$0.21	0.8%	$0.51	1.7%	0.9%
NA	$1.66	6.2%	$0.50	1.6%	(4.6%)
NO_x Cost	$0.52	1.9%	$0.43	1.4%	(0.5%)
Oil	$0.51	1.9%	$0.40	1.3%	(0.6%)
Ancillary Service Redispatch Cost	$0.27	1.0%	$0.29	0.9%	(0.0%)
CO_2 Cost	$0.05	0.2%	$0.14	0.5%	0.3%
SO_2 Cost	$0.09	0.3%	$0.06	0.2%	(0.1%)
Municipal Waste	$0.01	0.0%	$0.04	0.1%	0.1%
Other	$0.11	0.4%	$0.02	0.1%	(0.4%)
Market-to-Market Adder	$0.01	0.0%	$0.00	0.0%	(0.0%)
Uranium	$0.00	0.0%	($0.00)	(0.0%)	(0.0%)
Decrease Generation Adder	($0.03)	(0.1%)	($0.01)	(0.0%)	0.1%
LPA-SCED Differential	($0.01)	(0.0%)	($0.01)	(0.0%)	(0.0%)
Wind	($0.04)	(0.2%)	($0.20)	(0.7%)	(0.5%)
Total	$26.80	100.0%	$30.28	100.0%	0.0%

In order to accurately assess the markup behavior of market participants, real-time and day-ahead LMPs are decomposed using two different approaches. In the first approach (Table 3-70 and Table 3-77), markup is simply the difference between the price offer and the cost offer (unadjusted markup). In the second approach (Table 3-71 and Table 3-78), the 10 percent markup is removed from the cost offers of coal gas and oil units (adjusted markup).

The components of LMP are shown in Table 3-71, including markup using adjusted cost offers.

Table 3-71 Components of PJM real-time (Adjusted), load-weighted, average LMP: January 1 through March 31, 2016 and 2017

	2016 (Jan-Mar)		2017 (Jan-Mar)		Change
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Percent
Gas	$5.30	19.8%	$12.21	40.3%	20.6%
Coal	$14.78	55.1%	$9.81	32.4%	(22.7%)
Markup	$1.13	4.2%	$3.81	12.6%	8.4%
VOM	$2.04	7.6%	$1.34	4.4%	(3.2%)
Increase Generation Adder	$0.19	0.7%	$0.96	3.2%	2.5%
LPA Rounding Difference	$0.21	0.8%	$0.51	1.7%	0.9%
NA	$1.66	6.2%	$0.50	1.6%	(4.6%)
NO_x Cost	$0.52	1.9%	$0.43	1.4%	(0.5%)
Oil	$0.51	1.9%	$0.40	1.3%	(0.6%)
Ancillary Service Redispatch Cost	$0.27	1.0%	$0.29	0.9%	(0.0%)
CO_2 Cost	$0.05	0.2%	$0.14	0.5%	0.3%
SO_2 Cost	$0.09	0.3%	$0.06	0.2%	(0.1%)
Municipal Waste	$0.01	0.0%	$0.04	0.1%	0.1%
Other	$0.11	0.4%	$0.02	0.1%	(0.4%)
Market-to-Market Adder	$0.01	0.0%	$0.00	0.0%	(0.0%)
Uranium	$0.00	0.0%	($0.00)	(0.0%)	(0.0%)
Decrease Generation Adder	($0.03)	(0.1%)	($0.01)	(0.0%)	0.1%
Ten Percent Adder	$0.01	0.0%	($0.01)	(0.0%)	(0.1%)
LPA-SCED Differential	($0.01)	(0.0%)	($0.01)	(0.0%)	(0.0%)
Wind	($0.04)	(0.2%)	($0.20)	(0.7%)	(0.5%)
Total	$26.80	100.0%	$30.28	100.0%	0.0%

Table 3-72 Frequency and average shadow price of transmission constraints in PJM: 2016 and January 1 through March 31, 2017

	Frequency		Average Shadow Price	
Description	2016	2017 (Jan-Mar)	2016	2017 (Jan-Mar)
PJM Internal Violated Transmission Constraints	19,536	4,163	$643.04	$367.28
PJM Internal Binding Transmission Constraints	130,855	25,038	$120.13	$104.28
Market to Market Transmission Constraints	54,848	15,964	$264.34	$166.35
All Transmission Constraints	205,239	45,165	$208.44	$150.46

Day-Ahead LMP

Day-ahead average LMP is the hourly average LMP for the PJM Day-Ahead Energy Market.[78]

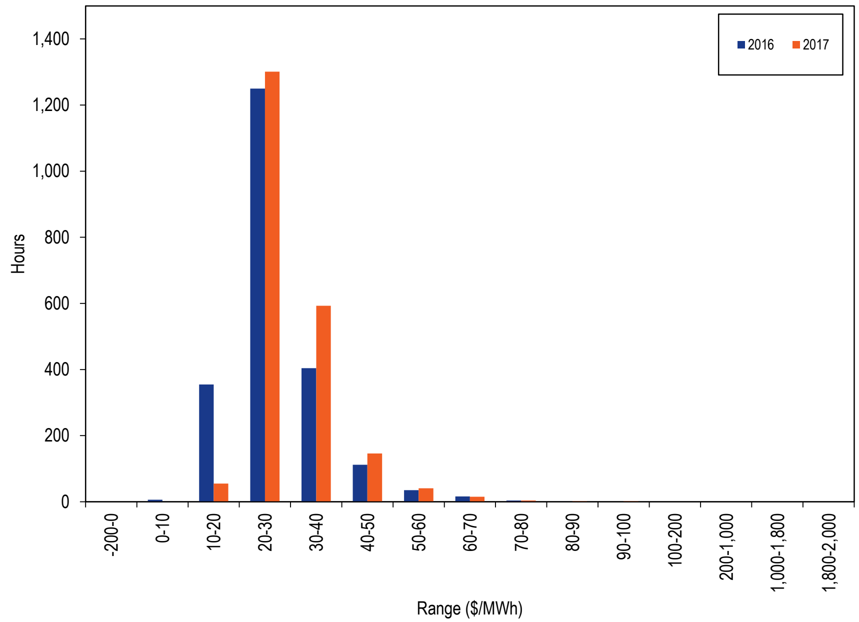
Day-Ahead Average LMP

PJM Day-Ahead Average LMP Duration

Figure 3-44 shows the hourly distribution of PJM day-ahead average LMP in the first three months of 2016 and 2017.

78 See the *MMU Technical Reference for the PJM Markets*, at "Calculating Locational Marginal Price" for a detailed definition of Day-Ahead LMP. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

Figure 3-44 Average LMP for the PJM Day-Ahead Energy Market: January 1 through March 31, 2016 and 2017



PJM Day-Ahead, Average LMP

Table 3-73 shows the PJM day-ahead, average LMP in the first three months of the 17-year period 2001 through 2017.

Table 3-73 PJM day-ahead, average LMP (Dollars per MWh): January 1 through March 31, 2001 through 2017

	Day-Ahead LMP			Year-to-Year Change		
Jan-Mar	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2001	$36.45	$32.72	$16.39	NA	NA	NA
2002	$22.43	$20.59	$7.56	(38.5%)	(37.1%)	(53.9%)
2003	$51.20	$46.06	$25.65	128.2%	123.7%	239.3%
2004	$45.84	$43.01	$18.85	(10.5%)	(6.6%)	(26.5%)
2005	$45.14	$41.56	$16.19	(1.5%)	(3.4%)	(14.1%)
2006	$51.23	$48.53	$14.16	13.5%	16.8%	(12.6%)
2007	$52.76	$49.43	$22.59	3.0%	1.9%	59.5%
2008	$66.10	$62.57	$23.90	25.3%	26.6%	5.8%
2009	$47.41	$43.43	$16.85	(28.3%)	(30.6%)	(29.5%)
2010	$46.13	$41.99	$15.93	(2.7%)	(3.3%)	(5.5%)
2011	$45.60	$41.10	$16.82	(1.2%)	(2.1%)	5.6%
2012	$30.82	$30.04	$6.63	(32.4%)	(26.9%)	(60.6%)
2013	$36.46	$34.45	$9.78	18.3%	14.7%	47.5%
2014	$86.52	$52.80	$92.80	137.3%	53.3%	848.8%
2015	$48.62	$35.48	$36.77	(43.8%)	(32.8%)	(60.4%)
2016	$26.90	$25.11	$8.83	(44.7%)	(29.2%)	(76.0%)
2017	$29.59	$27.33	$8.54	10.0%	8.8%	(3.3%)

Day-Ahead, Load-Weighted, Average LMP

Day-ahead, load-weighted LMP reflects the average LMP paid for day-ahead MWh. Day-ahead, load-weighted LMP is the average of PJM day-ahead hourly LMP, each weighted by the PJM total cleared day-ahead hourly load, including day-ahead fixed load, price-sensitive load, decrement bids and up to congestion.

PJM Day-Ahead, Load-Weighted, Average LMP

Table 3-74 shows the PJM day-ahead, load-weighted, average LMP in the first three months of the 17-year period 2001 through 2017.

Table 3-74 PJM day-ahead, load-weighted, average LMP (Dollars per MWh): January 1 through March 31, 2001 through 2017

	Day-Ahead, Load-Weighted, Average LMP			Year-to-Year Change		
Jan-Mar	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2001	$37.70	$34.55	$16.66	NA	NA	NA
2002	$23.17	$21.18	$7.76	(38.5%)	(38.7%)	(53.4%)
2003	$53.16	$48.69	$25.75	129.5%	129.9%	231.7%
2004	$47.75	$45.02	$19.19	(10.2%)	(7.5%)	(25.4%)
2005	$46.54	$42.88	$16.46	(2.5%)	(4.8%)	(14.2%)
2006	$52.40	$49.51	$14.29	12.6%	15.5%	(13.2%)
2007	$54.87	$51.89	$23.16	4.7%	4.8%	62.0%
2008	$68.00	$64.70	$24.35	23.9%	24.7%	5.1%
2009	$49.44	$44.85	$17.54	(27.3%)	(30.7%)	(28.0%)
2010	$47.77	$43.62	$16.52	(3.4%)	(2.7%)	(5.8%)
2011	$47.14	$42.49	$17.73	(1.3%)	(2.6%)	7.3%
2012	$31.51	$30.44	$6.83	(33.2%)	(28.3%)	(61.5%)
2013	$37.26	$35.02	$10.26	18.3%	15.0%	50.3%
2014	$94.97	$56.53	$102.23	154.9%	61.4%	896.7%
2015	$52.02	$36.94	$40.10	(45.2%)	(34.7%)	(60.8%)
2016	$27.94	$25.99	$9.28	(46.3%)	(29.6%)	(76.8%)
2017	$30.40	$27.99	$8.98	8.8%	7.7%	(3.3%)

Table 3-75 shows zonal day-ahead, and day-ahead, load-weighted, average LMP in the first three months of 2016 and 2017.

Table 3-75 Zone day-ahead and day-ahead, load-weighted, average LMP (Dollars per MWh): January 1 through March 31, 2016 and 2017

	Day-Ahead Average LMP			Day-Ahead, Load-Weighted, Average LMP		
Zone	2016 (Jan-Mar)	2017 (Jan-Mar)	Percent Change	2016 (Jan-Mar)	2017 (Jan-Mar)	Percent Change
AECO	$24.35	$28.77	18.2%	$25.38	$29.62	16.7%
AEP	$26.44	$29.02	9.7%	$27.30	$29.69	8.8%
AP	$27.78	$29.93	7.7%	$28.84	$30.80	6.8%
ATSI	$26.35	$30.03	13.9%	$27.04	$30.69	13.5%
BGE	$36.43	$33.28	(8.6%)	$38.70	$34.70	(10.3%)
ComEd	$23.64	$27.18	15.0%	$24.21	$27.70	14.4%
Day	$26.30	$29.42	11.8%	$27.02	$30.05	11.2%
DEOK	$25.78	$28.40	10.2%	$26.55	$29.05	9.4%
DLCO	$25.99	$29.28	12.6%	$26.71	$29.89	11.9%
Dominion	$31.17	$31.14	(0.1%)	$33.27	$32.59	(2.1%)
DPL	$30.52	$31.33	2.7%	$32.49	$32.80	0.9%
EKPC	$25.42	$28.17	10.8%	$26.41	$29.21	10.6%
JCPL	$23.04	$29.50	28.0%	$24.08	$30.42	26.3%
Met-Ed	$23.10	$29.42	27.4%	$23.96	$30.26	26.3%
PECO	$22.57	$28.49	26.2%	$23.56	$29.29	24.3%
PENELEC	$25.42	$29.11	14.5%	$26.45	$29.77	12.6%
Pepco	$32.88	$32.12	(2.3%)	$34.70	$33.32	(4.0%)
PPL	$23.23	$29.19	25.6%	$24.20	$30.01	24.0%
PSEG	$24.20	$29.85	23.3%	$25.19	$30.68	21.8%
RECO	$23.74	$30.00	26.4%	$24.56	$30.74	25.2%
PJM	$26.90	$29.59	10.0%	$27.94	$30.40	8.8%

PJM Day-Ahead, Monthly, Load-Weighted, Average LMP

Figure 3-45 shows the PJM day-ahead, monthly and annual, load-weighted LMP from June 2000 through March 2017.[79] The PJM day-ahead monthly load-weighted average LMP in May 2016 was $24.32, which is the lowest day-ahead monthly load-weighted average since May 2002 at $23.74.

79 Since the Day-Ahead Energy Market did not start until June 1, 2000, the day-ahead data for 2000 only includes data for the last six months of that year.

Figure 3-45 Day-ahead, monthly and annual, load-weighted, average LMP: June 1, 2000 through March 31, 2017

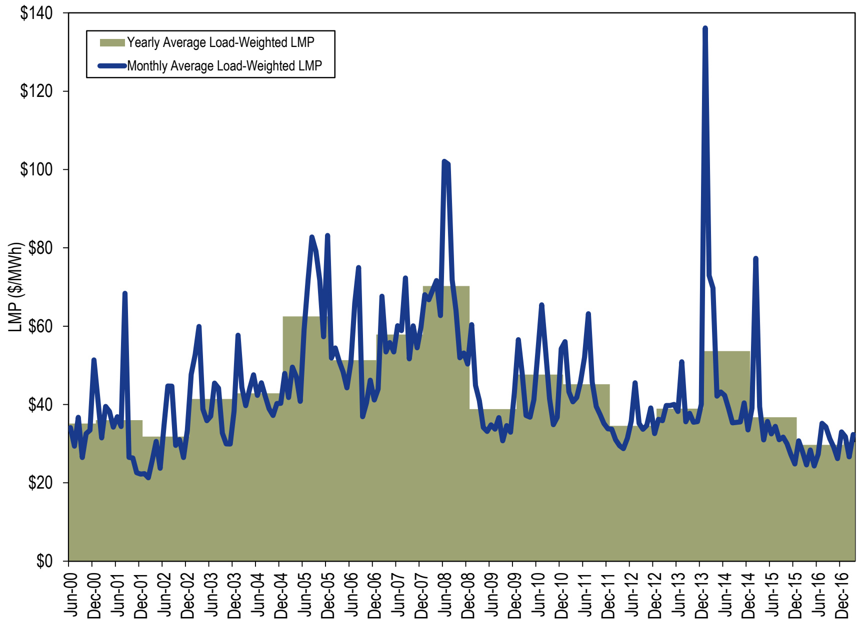
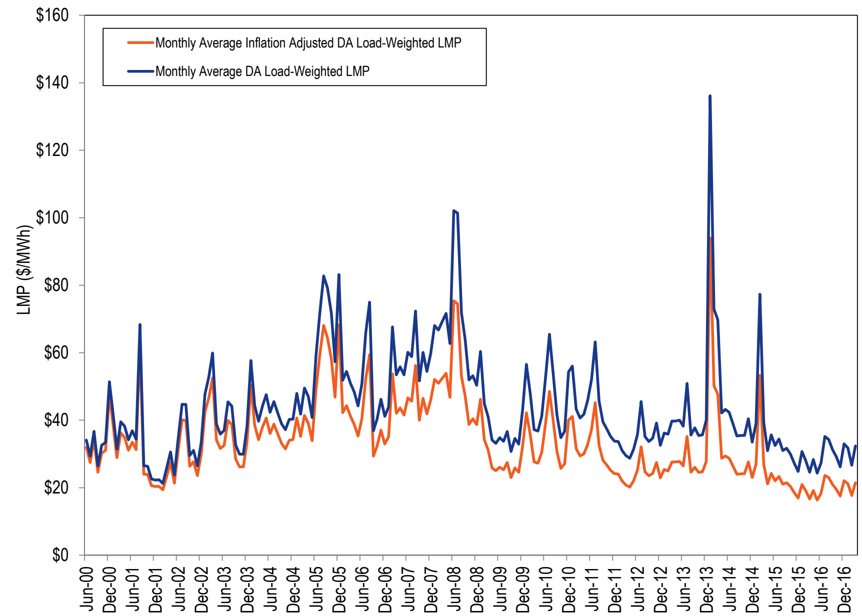


Figure 3-46 PJM day-ahead, monthly, load-weighted, average LMP and day-ahead, monthly inflation adjusted load-weighted, average LMP: June 1, 2000 through March 31, 2017



PJM Day-Ahead, Monthly, Inflation Adjusted Load-Weighted, Average LMP

Figure 3-48 shows the PJM day-ahead monthly load-weighted average LMP and inflation adjusted monthly day-ahead load-weighted average LMP for June 2000 through December 2016.[80] The PJM day-ahead inflation adjusted monthly load-weighted average LMP in May 2016 was $16.36, which is the lowest day-ahead monthly load-weighted average real LMP observed since PJM day-ahead markets started in 2000. Table 3-76 shows the PJM day-ahead yearly load- weighted average LMP and inflation adjusted yearly load-weighted average LMP for the first three months of every year from 2000 through 2017.

80 To obtain the inflation adjusted monthly load-weighted average LMP, the PJM system-wide load-weighted average LMP is deflated using 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>. (April 22, 2017).

Table 3-76 PJM day-ahead, yearly, load-weighted, average LMP and day-ahead, yearly inflation adjusted load-weighted, average LMP: January 1 through March 31, 2000 through 2017

Year	Load-Weighted, Average LMP	Inflation Adjusted Load-Weighted, Average LMP
2001	$37.70	$34.68
2002	$23.17	$21.04
2003	$53.16	$46.94
2004	$47.75	$41.47
2005	$46.54	$39.19
2006	$52.40	$42.57
2007	$54.87	$43.51
2008	$68.00	$51.82
2009	$49.44	$37.71
2010	$47.77	$35.59
2011	$47.14	$34.41
2012	$31.51	$22.35
2013	$37.26	$25.98
2014	$94.97	$65.40
2015	$52.02	$35.80
2016	$27.94	$19.03
2017	$30.40	$20.18

Components of Day-Ahead, Load-Weighted LMP

LMPs result from the operation of a market based on security-constrained, least-cost dispatch in which marginal resources determine system LMPs, based on their offers. For physical units, those offers can be decomposed into their components including fuel costs, emission costs, variable operation and maintenance costs, markup, FMU adder, day-ahead scheduling reserve (DASR) adder and the 10 percent cost offer adder. INC offers, DEC bids and up to congestion transactions are dispatchable injections and withdrawals in the Day-Ahead Energy Market with an offer price that cannot be decomposed. Using identified marginal resource offers and the components of unit offers, it is possible to decompose PJM system LMP using the components of unit offers and sensitivity factors.

Cost offers of marginal units are separated into their component parts. The fuel related component is based on unit specific heat rates and spot fuel prices. Emission costs are calculated using spot prices for NO_X, SO_2 and CO_2 emission credits, emission rates for NO_X, emission rates for SO_2 and emission rates for CO_2. CO_2 emission costs are applicable to PJM units in the PJM states that participate in RGGI: Delaware and Maryland.[81] Day-ahead scheduling reserve (DASR), lost opportunity cost (LOC) and DASR offer adders are the calculated contribution to LMP when redispatch of resources is needed in order to satisfy DASR requirements. The FMU adder is the calculated contribution of the FMU and AU adders to LMP that results when units with FMU or AU adders are marginal cost.

Table 3-77 shows the components of the PJM day-ahead, annual, load-weighted average LMP. In the first three months of 2017, 21.0 percent of the load-weighted LMP was the result of coal cost, 21.1 percent of the load-weighted LMP was the result of gas cost, 3.4 percent was the result of the up to congestion transaction cost, 24.7 percent was the result of DEC bid cost and 19.5 percent was the result of INC bid cost.

Table 3-77 Components of PJM day-ahead, (unadjusted), load-weighted, average LMP (Dollars per MWh): January 1 through March 31, 2016 and 2017

	2016 (Jan - Mar)		2017 (Jan - Mar)		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change Percent
DEC	$5.82	20.8%	$7.52	24.7%	3.9%
Gas	$3.55	12.7%	$6.40	21.1%	8.4%
Coal	$10.95	39.2%	$6.38	21.0%	(18.2%)
INC	$3.84	13.8%	$5.94	19.5%	5.8%
Ten Percent Cost Adder	$1.65	5.9%	$1.40	4.6%	(1.3%)
Up to Congestion Transaction	$1.29	4.6%	$1.04	3.4%	(1.2%)
VOM	$1.39	5.0%	$0.81	2.7%	(2.3%)
NO_x	$0.37	1.3%	$0.28	0.9%	(0.4%)
Dispatchable Transaction	$0.42	1.5%	$0.26	0.9%	(0.6%)
Markup	($1.63)	(5.8%)	$0.20	0.6%	6.5%
CO_2	$0.04	0.1%	$0.09	0.3%	0.1%
SO_2	$0.07	0.2%	$0.04	0.1%	(0.1%)
Oil	$0.06	0.2%	$0.03	0.1%	(0.1%)
Other	$0.11	0.4%	$0.01	0.0%	(0.4%)
Constrained Off	$0.01	0.0%	$0.00	0.0%	(0.0%)
DASR LOC Adder	$0.02	0.1%	$0.00	0.0%	(0.1%)
DASR Offer Adder	$0.00	0.0%	$0.00	0.0%	(0.0%)
Wind	($0.01)	(0.1%)	($0.01)	(0.0%)	0.0%
NA	($0.00)	(0.0%)	$0.00	0.0%	0.0%
Total	$27.94	100.0%	$30.40	100.0%	(0.0%)

81 New Jersey withdrew from RGGI, effective January 1, 2012.

Table 3-78 shows the components of the PJM day-ahead, annual, load-weighted average LMP including the adjusted markup calculated by excluding the 10 percent adder from the coal, gas or oil units.

Table 3-78 Components of PJM day-ahead, (adjusted), load-weighted, average LMP (Dollars per MWh): January 1 through March 31, 2016 and 2017

	2016 (Jan - Mar)		2017 (Jan - Mar)		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change Percent
DEC	$5.82	20.8%	$7.52	24.7%	3.9%
Gas	$3.55	12.7%	$6.40	21.1%	8.4%
Coal	$10.95	39.2%	$6.38	21.0%	(18.2%)
INC	$3.84	13.8%	$5.94	19.5%	5.8%
Markup	$0.00	0.0%	$1.56	5.1%	5.1%
Up to Congestion Transaction	$1.29	4.6%	$1.04	3.4%	(1.2%)
VOM	$1.39	5.0%	$0.81	2.7%	(2.3%)
NO_x	$0.37	1.3%	$0.28	0.9%	(0.4%)
Dispatchable Transaction	$0.42	1.5%	$0.26	0.9%	(0.6%)
CO_2	$0.04	0.1%	$0.09	0.3%	0.1%
SO_2	$0.07	0.2%	$0.04	0.1%	(0.1%)
Ten Percent Cost Adder	$0.02	0.1%	$0.04	0.1%	0.1%
Oil	$0.06	0.2%	$0.03	0.1%	(0.1%)
Other	$0.11	0.4%	$0.01	0.0%	(0.4%)
Constrained Off	$0.01	0.0%	$0.00	0.0%	(0.0%)
DASR LOC Adder	$0.02	0.1%	$0.00	0.0%	(0.1%)
DASR Offer Adder	$0.00	0.0%	$0.00	0.0%	(0.0%)
Wind	($0.01)	(0.1%)	($0.01)	(0.0%)	0.0%
NA	($0.00)	(0.0%)	$0.00	0.0%	0.0%
Total	$27.94	100.0%	$30.40	100.0%	(0.0%)

Price Convergence

The introduction of the PJM Day-Ahead Energy Market with virtuals as part of the design created the possibility that competition, exercised through the use of virtual offers and bids, could tend to cause prices in the Day-Ahead and Real-Time Energy Markets to converge more than would be the case without virtuals. Convergence is not the goal of virtual trading, but it is a possible outcome. The degree of convergence, by itself, is not a measure of the competitiveness or effectiveness of the Day-Ahead Energy Market. Price convergence does not necessarily mean a zero or even a very small difference in prices between Day-Ahead and Real-Time Energy Markets. There may be factors, from operating reserve charges to differences in risk that result in a competitive, market-based differential. In addition, convergence in the sense that day-ahead and real-time prices are equal at individual buses or aggregates on a day to day basis is not a realistic expectation as a result of uncertainty, lags in response time and modeling differences, such as differences in modeled contingencies and marginal loss calculations, between the Day-Ahead and Real-Time Energy Market.

Where arbitrage opportunities are created by differences between day-ahead and real-time energy market expectations, reactions by market participants may lead to more efficient market outcomes but there is no guarantee that the results of virtual bids and offers will result in more efficient market outcomes.

Where arbitrage incentives are created by systematic modeling differences, such as differences between the day-ahead and real-time modeled transmission contingencies and marginal loss calculations, virtual bids and offers cannot result in more efficient market outcomes. Such offers may be profitable but cannot change the underlying reason for the price difference. The virtual transactions will continue to profit from the activity for that reason regardless of the volume of those transactions. This is termed false arbitrage.

INCs, DECs and UTCs allow participants to profit from price differences between the Day-Ahead and Real-Time Energy Market. Absent a physical position in real time, the seller of an INC must buy energy in the Real-Time Energy Market to fulfill the financial obligation to provide energy. If the day-ahead price for energy is higher than the real-time price for energy, the INC makes a profit. Absent a physical position in real time, the buyer of a DEC must sell energy in the Real-Time Energy Market to fulfill the financial obligation to buy energy. If the day-ahead price for energy is lower than the real-time price for energy, the DEC makes a profit.

The profitability of a UTC transaction is the net of the separate profitability of the component INC and DEC. A UTC can be net profitable if the profit on one side of the UTC transaction exceeds the losses on the other side.

Table 3-79 shows the number of cleared UTC transactions, the number of profitable cleared UTCs, the number of cleared UTCs that were profitable at their source point and the number of cleared UTCs that were profitable at their sink point in the first three months of 2016 and 2017. In the first three months of 2017, 53.0 percent of all cleared UTC transactions were net profitable. Of cleared UTC transactions, 66.1 percent were profitable on the source side and 34.4 were profitable on the sink side but only 4.9 percent were profitable on both the source and sink side.

Table 3-79 Cleared UTC profitability by source and sink point: January 1 through March 31, 2016 and 2017[82]

Jan-Mar	Cleared UTCs	Profitable UTCs	UTC Profitable at Source Bus	UTC Profitable at Sink Bus	Profitable UTC	Profitable Source	Profitable Sink
2016	4,549,904	2,160,463	3,192,971	1,290,673	47.5%	70.2%	28.4%
2017	6,164,808	3,267,720	4,072,387	2,123,007	53.0%	66.1%	34.4%

Figure 3-47 shows total UTC daily gross profits and losses and net profits and losses in the first three months of 2017.

Figure 3-47 UTC daily gross profits and losses and net profits: January 1 through March 31, 2017[83]

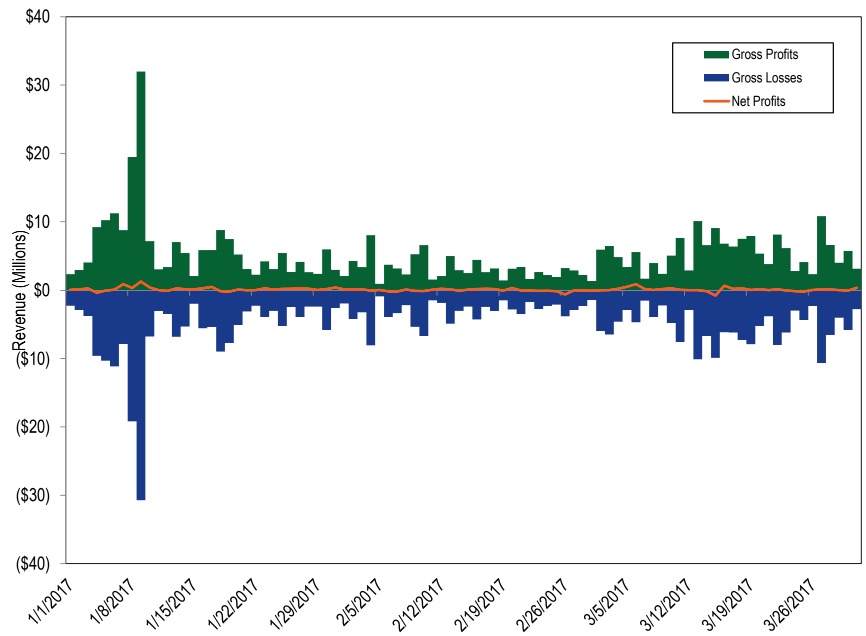


Figure 3-48 shows the cumulative UTC daily profits for the years 2013 through 2016. UTC profits during this period were primarily a result of significant unanticipated price differences between day ahead and real time LMPs. For example, the cumulative daily UTC profits in 2014 were greater than for the other three years as a result of profits from the significant and unanticipated day-ahead and real-time price differences that resulted from the polar vortex conditions in January 2014. Similarly, cumulative daily UTC profits increased during late February 2015 as a result of profits from the significant day-ahead and real-time prices differences that resulted from cold weather conditions. The cumulative daily UTC profits for 2016 are the lowest of these four years as a result of low and stable LMPs and stable prices during 2016.

82 Calculations exclude PJM administrative charges.

83 Calculations exclude PJM administrative charges.

Figure 3-48 Cumulative daily UTC profits: January 1, 2013 through March 31, 2017

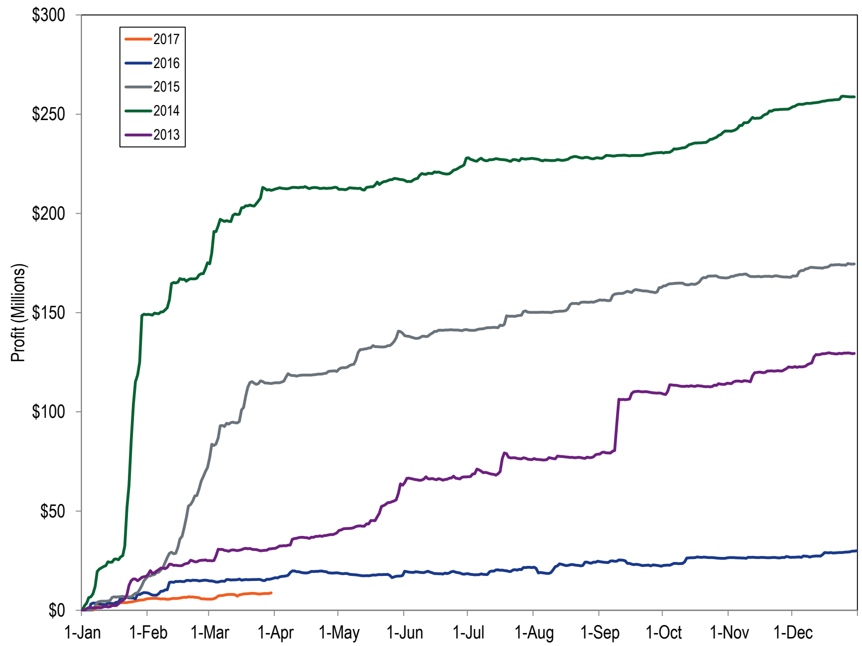


Table 3-80 shows UTC profits by month for 2013 through March 2017. May 2016, September 2016 and February 2017 were the only months in the past five years where the total monthly profits were negative.

There are incentives to use virtual transactions to profit from price differences between the Day-Ahead and Real-Time Energy Markets, but there is no guarantee that such activity will result in price convergence and no data to support that claim. As a general matter, virtual offers and bids are based on expectations about both day-ahead and real-time energy market conditions and reflect the uncertainty about conditions in both markets and the fact that these conditions change hourly and daily. PJM markets do not provide a mechanism that could result in immediate convergence after a change in system conditions as there is at least a one day lag after any change in system conditions before offers could reflect such changes.

Substantial virtual trading activity does not guarantee that market power cannot be exercised in the Day-Ahead Energy Market. Hourly and daily price differences between the Day-Ahead and Real-Time Energy Markets fluctuate continuously and substantially from positive to negative. There may be substantial, persistent differences between day-ahead and real-time prices even on a monthly basis (Figure 3-50).

Analysis of the data from September 1, 2013, through September 30, 2015, does not support the conclusion that UTCs contribute in any measurable way to price convergence. In addition, the sudden and significant reduction in UTC activity in September of 2014 did not cause a measurable change in price convergence.

Table 3-80 UTC profits by month: January 1, 2013 through March 31, 2017

	January	February	March	April	May	June	July	August	September	October	November	December	Total
2013	$17,048,654	$8,304,767	$5,629,392	$7,560,773	$25,219,947	$3,484,372	$8,781,526	$2,327,168	$31,160,618	$4,393,583	$8,730,701	$6,793,990	$129,435,490
2014	$148,973,434	$23,235,621	$39,448,716	$1,581,786	$3,851,636	$7,353,460	$3,179,356	$287,824	$2,727,763	$10,889,817	$11,042,443	$6,191,101	$258,762,955
2015	$16,132,319	$53,830,098	$44,309,656	$6,392,939	$19,793,475	$824,817	$8,879,275	$5,507,608	$6,957,012	$4,852,454	$392,876	$6,620,581	$174,493,110
2016	$8,874,363	$6,118,477	$1,119,457	$2,768,591	($1,333,563)	$841,706	$3,128,346	$3,200,573	($2,518,408)	$4,216,717	$254,684	$3,271,368	$29,942,312
2017	$5,716,757	($17,860)	$3,083,173										$8,782,071

Table 3-81 shows that the difference between the average real-time price and the average day-ahead price was -\$1.30 per MWh in the first three months of 2016, and -\$0.20 per MWh in the first three months of 2017. The difference between average peak real-time price and the average peak day-ahead price was -\$0.96 per MWh in the first three months of 2016 and -\$0.70 per MWh in the first three months of 2017.

Table 3-81 Day-ahead and real-time average LMP (Dollars per MWh): January 1 through March 31, 2016 and 2017[84]

	Jan-Mar 2016				Jan-Mar 2017			
	Day-Ahead	Real-Time	Difference	Percent of Real Time	Day-Ahead	Real-Time	Difference	Percent of Real Time
Average	$26.90	$25.60	($1.30)	(5.1%)	$29.59	$29.39	($0.20)	(0.7%)
Median	$25.11	$22.91	($2.20)	(9.6%)	$27.33	$25.71	($1.62)	(6.3%)
Standard deviation	$8.83	$12.99	$4.15	32.0%	$8.54	$12.28	$3.74	30.5%
Peak average	$29.85	$28.89	($0.96)	(3.3%)	$32.48	$31.77	($0.70)	(2.2%)
Peak median	$27.68	$24.72	($2.96)	(12.0%)	$30.39	$27.91	($2.47)	(8.9%)
Peak standard deviation	$8.00	$13.87	$5.88	42.3%	$8.54	$12.44	$3.90	31.4%
Off peak average	$24.28	$22.69	($1.59)	(7.0%)	$26.99	$27.24	$0.25	0.9%
Off peak median	$22.44	$20.87	($1.57)	(7.5%)	$24.42	$23.79	($0.63)	(2.6%)
Off peak standard deviation	$8.72	$11.39	$2.67	23.5%	$7.66	$11.74	$4.07	34.7%

The price difference between the Real-Time and the Day-Ahead Energy Markets results in part, from conditions in the Real-Time Energy Market that are difficult, or impossible, to anticipate in the Day-Ahead Energy Market.

Table 3-82 shows the difference between the real-time and the day-ahead energy market prices for the first three months of 2001 through 2017.

Table 3-82 Day-ahead and real-time average LMP (Dollars per MWh): January 1 through March 31, 2001 through 2017

Jan-Mar	Day-Ahead	Real-Time	Difference	Percent of Real Time
2001	$36.45	$33.77	($2.68)	(7.3%)
2002	$22.43	$22.23	($0.20)	(0.9%)
2003	$51.20	$49.57	($1.63)	(3.2%)
2004	$45.84	$46.37	$0.52	1.1%
2005	$45.14	$46.51	$1.37	3.0%
2006	$51.23	$52.98	$1.75	3.4%
2007	$52.76	$55.34	$2.58	4.9%
2008	$66.10	$66.75	$0.65	1.0%
2009	$47.41	$47.29	($0.12)	(0.2%)
2010	$46.13	$44.13	($2.00)	(4.3%)
2011	$45.60	$44.76	($0.84)	(1.8%)
2012	$30.82	$30.38	($0.43)	(1.4%)
2013	$36.46	$36.33	($0.13)	(0.4%)
2014	$86.52	$84.04	($2.48)	(2.9%)
2015	$48.62	$47.39	($1.23)	(2.5%)
2016	$26.90	$25.60	($1.30)	(4.8%)
2017	$29.59	$29.39	($0.20)	(0.7%)

Table 3-83 provides frequency distributions of the differences between PJM real-time hourly LMP and PJM day-ahead hourly LMP for the first three months of 2007 through 2017.

84 The averages used are the annual average of the hourly average PJM prices for day-ahead and real-time.

Table 3-83 Frequency distribution by hours of PJM real-time LMP minus day-ahead LMP (Dollars per MWh): January 1 through March 31, 2007 through 2017

Jan-Mar	2007		2008		2009		2010		2011		2012		2013		2014	
LMP	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent
< ($1,000)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
($1,000) to ($750)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	2	0.09%
($750) to ($500)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	3	0.23%
($500) to ($450)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	1	0.28%
($450) to ($400)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	6	0.56%
($400) to ($350)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	5	0.79%
($350) to ($300)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	5	1.02%
($300) to ($250)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	6	1.30%
($250) to ($200)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	14	1.95%
($200) to ($150)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	14	2.59%
($150) to ($100)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	1	0.05%	0	0.00%	0	0.00%	45	4.68%
($100) to ($50)	14	0.65%	21	0.96%	1	0.05%	5	0.23%	17	0.83%	2	0.09%	0	0.00%	88	8.75%
($50) to $0	1,214	56.88%	1,309	60.93%	1,347	62.44%	1,569	72.90%	1,464	68.64%	1,566	71.83%	1,542	71.42%	1,242	66.28%
$0 to $50	847	96.11%	740	94.82%	788	98.93%	547	98.24%	619	97.31%	601	99.36%	587	98.61%	595	93.84%
$50 to $100	73	99.49%	97	99.27%	21	99.91%	33	99.77%	51	99.68%	12	99.91%	23	99.68%	55	96.39%
$100 to $150	7	99.81%	14	99.91%	2	100.00%	1	99.81%	6	99.95%	2	100.00%	3	99.81%	27	97.64%
$150 to $200	0	99.81%	1	99.95%	0	100.00%	4	100.00%	1	100.00%	0	100.00%	3	99.95%	16	98.38%
$200 to $250	1	99.86%	1	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	99.95%	9	98.80%
$250 to $300	1	99.91%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	1	100.00%	8	99.17%
$300 to $350	2	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	2	99.26%
$350 to $400	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	3	99.40%
$400 to $450	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	1	99.44%
$450 to $500	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	99.44%
$500 to $750	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	7	99.77%
$750 to $1,000	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	99.77%
$1,000 to $1,250	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	1	99.81%
>= $1,250	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	4	100.00%

Table 3-83 Frequency distribution by hours of PJM real-time LMP minus day-ahead LMP (Dollars per MWh): January 1 through March 31, 2007 through 2017 (continued)

Jan-Mar	2015		2016		2017	
LMP	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent
< ($1,000)	0	0.00%	0	0.00%	0	0.00%
($1,000) to ($750)	0	0.00%	0	0.00%	0	0.00%
($750) to ($500)	0	0.00%	0	0.00%	0	0.00%
($500) to ($450)	0	0.00%	0	0.00%	0	0.00%
($450) to ($400)	0	0.00%	0	0.00%	0	0.00%
($400) to ($350)	0	0.00%	0	0.00%	0	0.00%
($350) to ($300)	0	0.00%	0	0.00%	0	0.00%
($300) to ($250)	0	0.00%	0	0.00%	0	0.00%
($250) to ($200)	0	0.00%	0	0.00%	0	0.00%
($200) to ($150)	2	0.09%	0	0.00%	0	0.00%
($150) to ($100)	12	0.65%	0	0.00%	0	0.00%
($100) to ($50)	43	2.64%	0	0.00%	0	0.00%
($50) to $0	1,504	72.30%	1,657	75.90%	1,443	66.84%
$0 to $50	516	96.20%	514	99.45%	707	99.58%
$50 to $100	54	98.70%	8	99.82%	8	99.95%
$100 to $150	21	99.68%	4	100.00%	1	100.00%
$150 to $200	5	99.91%	0	100.00%	0	100.00%
$200 to $250	1	99.95%	0	100.00%	0	100.00%
$250 to $300	1	100.00%	0	100.00%	0	100.00%
$300 to $350	0	100.00%	0	100.00%	0	100.00%
$350 to $400	0	100.00%	0	100.00%	0	100.00%
$400 to $450	0	100.00%	0	100.00%	0	100.00%
$450 to $500	0	100.00%	0	100.00%	0	100.00%
$500 to $750	0	100.00%	0	100.00%	0	100.00%
$750 to $1,000	0	100.00%	0	100.00%	0	100.00%
$1,000 to $1,250	0	100.00%	0	100.00%	0	100.00%
>= $1,250	0	100.00%	0	100.00%	0	100.00%

Figure 3-49 shows the hourly differences between day-ahead and real-time hourly LMP in the first three months of 2017.

Figure 3-49 Real-time hourly LMP minus day-ahead hourly LMP: January 1 through March 31, 2017

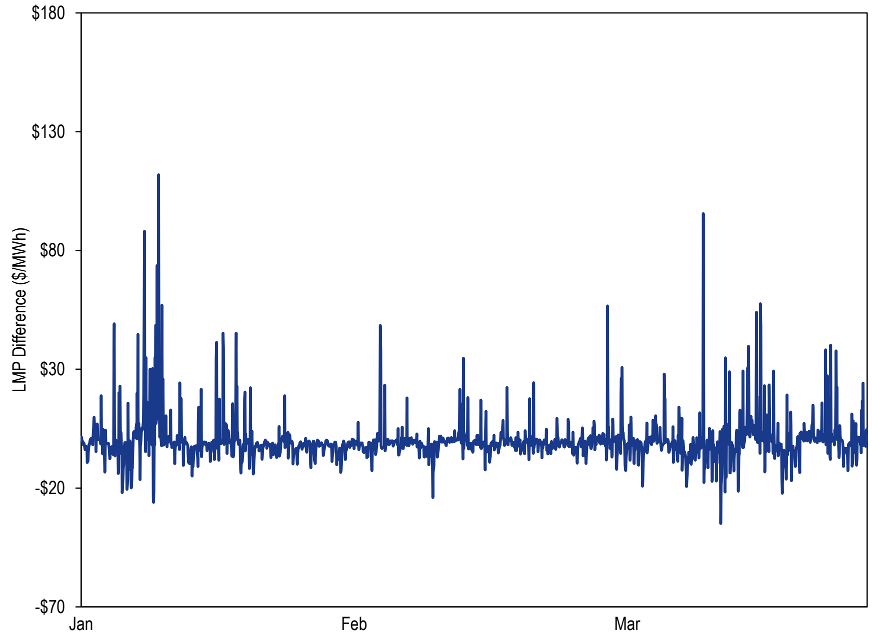


Figure 3-50 shows the monthly average of the differences between the day-ahead and real-time PJM average LMPs from January 2013, through March 2017.

Figure 3-50 Monthly average of real-time minus day-ahead LMP: January 1, 2013 through March 31, 2017

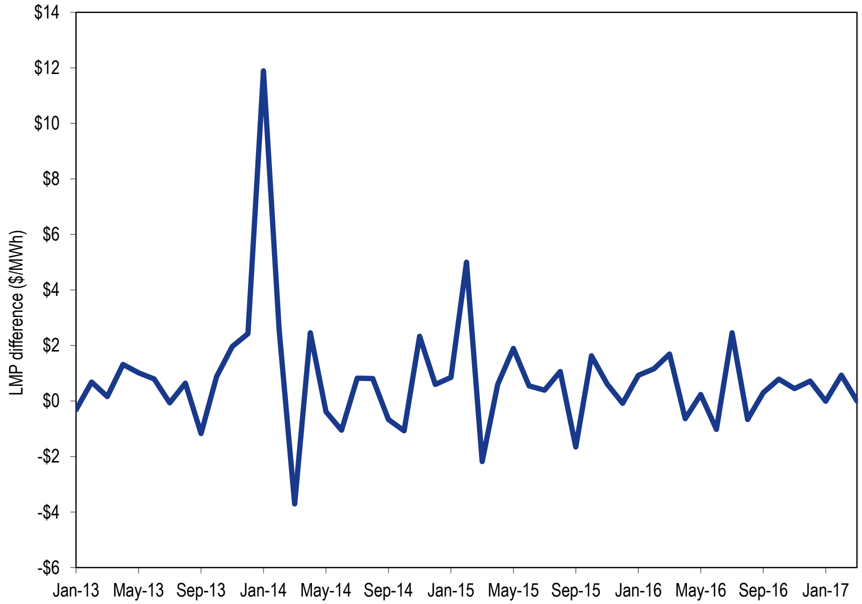


Figure 3-51 Monthly average of the absolute value of real-time minus day-ahead LMP by pnode: January 1, 2013 through March 31, 2017

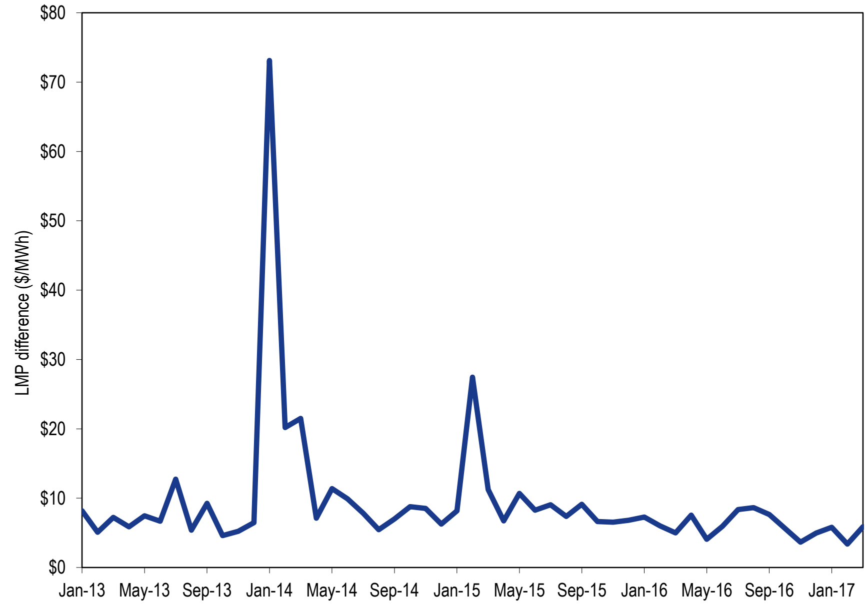
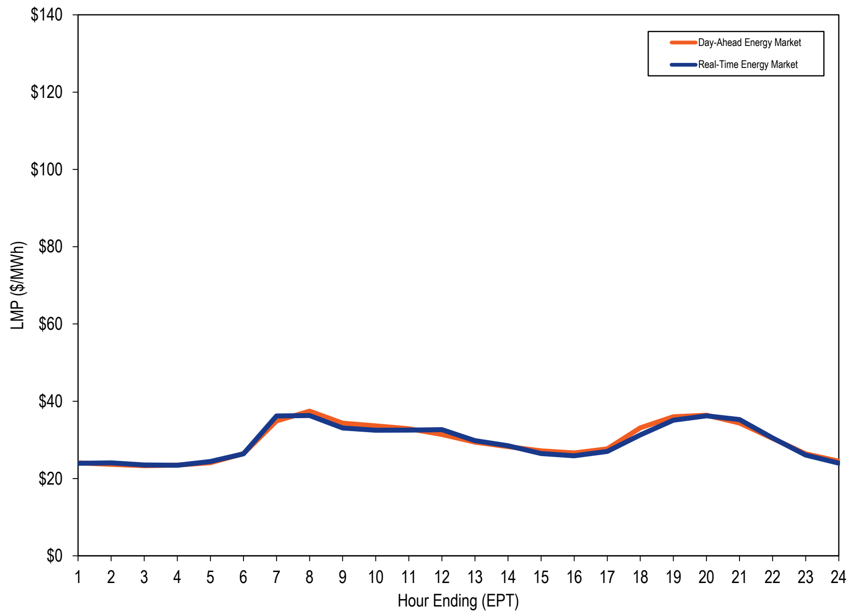


Figure 3-51 shows the monthly average of the absolute value of the differences between the day-ahead and real-time hourly, nodal LMPs from January 2013, through March 2017.

Figure 3-52 shows day-ahead and real-time LMP on an average hourly basis for the first three months of 2017.

Figure 3-52 PJM system hourly average LMP: January 1 through March 31, 2017



Scarcity

PJM's Energy Market experienced no shortage pricing events in the first three months of 2017. Table 3-84 shows a summary of the number of days emergency alerts, warnings and actions were declared in PJM in the first three months of 2016 and 2017.

Table 3-84 Summary of emergency events declared: January 1 through March 31, 2016 and 2017

	Number of days events declared	
Event Type	Jan - Mar, 2016	Jan - Mar, 2017
Cold Weather Alert	4	0
Hot Weather Alert	0	0
Maximum Emergency Generation Alert	0	0
Primary Reserve Alert	0	0
Voltage Reduction Alert	0	0
Primary Reserve Warning	0	0
Voltage Reduction Warning	0	0
Pre Emergency Mandatory Load Management Reduction Action	0	0
Emergency Mandatory Load Management Reduction Action (30, 60 or 120 minute lead time)	0	0
Maximum Emergency Action	0	0
Emergency Energy Bids Requested	0	0
Voltage Reduction Action	0	0
Shortage Pricing	0	0
Energy export recalls from PJM capacity resources	0	0

Emergency Procedures

PJM declares alerts at least a day prior to the operating day to warn members of possible emergency actions that could be taken during the operating day. In real time on the operating day, PJM issues warnings notifying members of system conditions that could result in emergency actions during the operating day.

PJM did not declare any cold weather alerts in the first three months of 2017 compared to four days in the first three months of 2016.[85] The purpose of a cold weather alert is to prepare personnel and facilities for expected extreme cold weather conditions, generally when temperatures are forecast to approach minimums or fall below 10 degrees Fahrenheit.

PJM did not declare any hot weather alerts in the first three months of 2017 and 2016.[86] The purpose of a hot weather alert is to prepare personnel and facilities for expected extreme hot and humid weather conditions, generally

85 See PJM. "Manual 13: Emergency Operations," Revision 61 (January 1, 2017), Section 3.3 Cold Weather Alert, p. 54.
86 See PJM. "Manual 13: Emergency Operations," Revision 61 (January 1, 2017), Section 3.4 Hot Weather Alert, p. 58.

when temperatures are forecast to exceed 90 degrees Fahrenheit with high humidity.

PJM did not declare any maximum emergency generation alert in the first three months of 2017 and 2016. The purpose of a maximum emergency generation alert is to provide an alert at least one day prior to the operating day that system conditions may require use of PJM emergency actions. It is called to alert PJM members that maximum emergency generation may be requested in the operating capacity.[87] This means that if PJM directs members to load maximum emergency generation during the operating day, the resources must be able to increase generation above the maximum economic level of their offer.

PJM did not declare any primary reserve alerts in the first three months of 2017 and 2016. The purpose of a primary reserve alert is to alert members at least one day prior to the operating day that available primary reserves are anticipated to be short of the primary reserve requirement on the operating day. It is issued when the estimated primary reserves are less than the forecast primary reserve requirement.

PJM did not declare any voltage reduction alert in the first three months of 2017 and 2016. The purpose of a voltage reduction alert is to alert members at least one day prior to the operating day that a voltage reduction may be required on the operating day. It is issued when the estimated operating reserve is less than the forecast synchronized reserve requirement.

PJM did not declare any primary reserve warning in the first three months of 2017 and 2016. The purpose of a primary reserve warning is to warn members that available primary reserves are less than the primary reserve requirement but greater than the synchronized reserve requirement.

PJM did not declare any voltage reduction warnings and reductions of noncritical plant load in the first three months of 2017 and 2016. The purpose of a voltage reduction warning and reduction of noncritical plant load is to warn members that available synchronized reserves are less than the synchronized reserve requirement and that a voltage reduction may be required. It can be issued for the RTO or for specific control zones.

PJM did not declare any emergency mandatory load management reductions in the first three months of 2017 and 2016. The purpose of emergency mandatory load management is to request curtailment service providers (CSP) to implement load reductions from demand resources registered in PJM demand response programs that have a lead time of between one and two hours (long lead time) and a lead time of up to one hour (short lead time). Starting in June 2014, PJM combined the long lead and short lead emergency load management action procedures into Emergency Mandatory Load Management Reduction Action (30, 60 or 120 minute lead time). PJM dispatch declares NERC Energy Emergency Alert level 2 (EEA2) concurrent with Emergency Mandatory load Management Reductions. PJM also added a Pre-Emergency Mandatory Load Management Reduction Action (30, 60 or 120 minute lead time) step to request load reductions before declaring emergency load management reductions.

PJM did not declare any maximum emergency generation actions in the first three months of 2017 and 2016. The purpose of a maximum emergency generation action is to request generators to increase output to the maximum emergency level which unit owners may define at a level above the maximum economic level. A maximum emergency generation action can be issued for the RTO, for specific control zones or for parts of control zones.

PJM did not request any offers for emergency energy purchases in the first three months of 2017 and 2016.

PJM did not declare any voltage reduction actions in the first three months of 2017 and 2016. The purpose of a voltage reduction is to reduce load to provide sufficient reserves, to maintain tie flow schedules, and to preserve limited energy sources. When a voltage reduction action is issued for a reserve zone or subzone, the primary reserve penalty factor and synchronized reserve penalty factor are incorporated into the synchronized and nonsynchronized

87 See PJM. "Manual 13: Emergency Operations," Revision 61 (January 1, 2017), Section 2.3.1 Advance Notice Emergency Procedures: Alerts, p. 18.

reserve market clearing prices and locational marginal prices until the voltage reduction action has been terminated.

PJM declared nine synchronized reserve events in the first three months of 2017 compared to three synchronized reserve events in the first three months of 2016.[88] Synchronized reserve events may occur at any time of the year due to sudden loss of generation or transmission facilities and do not necessarily coincide with capacity emergency conditions such as maximum generation emergency events or emergency load management events.

Table 3-85 provides a description of PJM declared emergency procedures.

88 See *2017 Quarterly State of the Market Report for PJM: January through March*, Section 10: Ancillary Service Markets for details on the spinning events.

Table 3-85 Description of emergency procedures

Emergency Procedure	Purpose
Cold Weather Alert	To prepare personnel and facilities for extreme cold weather conditions, generally when forecast weather conditions approach minimum or temperatures fall below ten degrees Fahrenheit.
Hot Weather Alert	To prepare personnel and facilities for extreme hot and/or humid weather conditions, generally when forecast temperatures exceed 90 degrees with high humidity.
Maximum Emergency Generation Alert	To provide an early alert at least one day prior to the operating day that system conditions may require the use of the PJM emergency procedures and resources must be able to increase generation above the maximum economic level of their offers.
Primary Reserve Alert	To alert members of a projected shortage of primary reserve for a future period. It is implemented when estimated primary reserve is less than the forecast requirement.
Voltage Reduction Alert	To alert members that a voltage reduction may be required during a future critical period. It is implemented when estimated reserve capacity is less than forecasted synchronized reserve requirement.
Pre-Emergency Load Management Reduction Action	To request load reductions from customers registered in the PJM Demand Response program that need 30, 60, or 120 minute lead time before declaring emergency load management reductions
Emergency Mandatory Load Management Reduction Action	To request load reductions from customers registered in the PJM Demand Response program that need 30, 60, or 120 minute lead time to provide additional load relief, generally declared simultaneously with NERC Energy Emergency Alert Level 2 (EEA2)
Primary Reserve Warning	To warn members that available primary reserve is less than required and present operations are becoming critical. It is implemented when available primary reserve is less than the primary reserve requirement but greater than the synchronized reserve requirement.
Maximum Emergency Generation Action	To provide real time notice to increase generation above the maximum economic level. It is implemented whenever generation is needed that is greater than the maximum economic level.
Voltage Reduction Warning & Reduction of Non-Critical Plant Load	To warn members that actual synchronized reserves are less than the synchronized reserve requirement and that voltage reduction may be required.
Deploy All Resources Action	For emergency events that do not evolve over time, but rather develop rapidly and without prior warning, PJM issues this action to instruct all generation resources to be online immediately and to all load management resources to reduce load immediately.
Manual Load Dump Warning	To warn members of the critical condition of present operations that may require manually dumping load. Issued when available primary reserve capacity is less than the largest operating generator or the loss of a transmission facility jeopardizes reliable operations after all other possible measures are taken to increase reserve.
Voltage Reduction Action	To reduce load to provide sufficient reserve capacity to maintain tie flow schedules and preserve limited energy sources. It is implemented when load relief is needed to maintain tie schedules.
Manual Load Dump Action	To provide load relief when all other possible means of supplying internal PJM RTO load have been used to prevent a catastrophe within the PJM RTO or to maintain tie schedules so as not to jeopardize the reliability of the other interconnected regions.

Scarcity and Scarcity Pricing

In electricity markets, scarcity means that demand, including reserve requirements, is nearing the limits of the available capacity of the system. Under the PJM rules that were in place through September 30, 2012, high prices, or scarcity pricing, resulted from high offers by individual generation owners for specific units when the system was close to its available capacity. But this was not an efficient way to manage scarcity pricing and made it difficult to distinguish between market power and scarcity pricing.

On October 1, 2012, PJM introduced a new administrative scarcity pricing regime. Under the current PJM market rules, shortage pricing conditions are triggered when there is a shortage of synchronized or primary reserves in the RTO or in the Mid-Atlantic and Dominion (MAD) Subzone. In times of reserve shortage, the value of reserves is included as a penalty factor in the optimization and in the price of energy.[89] Shortage pricing is also triggered when PJM issues a voltage reduction action or a manual load dump action for a reserve zone or a reserve subzone. When shortage pricing is triggered, the primary reserve penalty factor and the synchronized reserve penalty factor are incorporated in the calculation of the synchronized and nonsynchronized reserve market clearing prices and the locational marginal price.

In the first three months of 2017, there were no shortage pricing events triggered in PJM.

Final Rule on Shortage Pricing and Settlement Intervals

On September 17, 2015, the Commission issued a Notice of Proposed Rulemaking (NOPR) in which the Commission proposed to address price formation issues in RTOs/ISOs ("price formation NOPR").[90] In particular, the price formation NOPR proposed (i) to require the alignment of settlement and dispatch intervals for energy and operating reserves; and (ii) to require that each RTO/ISO trigger shortage pricing for any dispatch interval during which a shortage of energy or operating reserves occurs. These proposed reforms are intended to ensure that resources have price signals that provide incentives to conform their output to dispatch instructions, and that prices reflect operating needs at each dispatch interval.[91]

On June 16, 2016, the Commission issued a Final Rule in which it required each RTO/ISO to settle energy, operating reserves and intertie transactions using the same time intervals that it uses for to dispatch units or schedule these transactions (Order No. 825).[92] In PJM, the energy market dispatch and pricing interval is five minutes, and the order requires PJM to settle energy transactions on a five minute basis. In PJM, the synchronized reserve and regulation market dispatch and pricing interval is five minutes, and the order requires PJM to settle these reserves on a five minute basis. In PJM, intertie transactions are scheduled on fifteen minute intervals, and the order requires PJM to settle intertie transactions on a fifteen minute basis. However, the Commission allowed PJM to propose a shorter time interval for settling intertie transactions.[93]

The Commission also required each RTO/ISO to trigger shortage pricing for any dispatch and pricing interval in which a shortage of energy or operating reserves is indicated by the RTO/ISO's software.[94] In PJM, the rule would require PJM to trigger shortage pricing for any five minute interval when the Real-Time SCED (Security Constrained Economic Dispatch) indicates a shortage of synchronized reserves or primary reserves. Currently in PJM, if the dispatch tools (Intermediate-Term and Real-Time SCED) reflect a shortage of reserves (primary or synchronized) for a time period shorter than a defined threshold (30 minutes) due to ramp limitations or unit startup delays, it is considered a transient shortage, a shortage event is not declared, and shortage pricing is not implemented. Currently, both Real-Time SCED and Intermediate-Term SCED have to consistently identify that a shortage of a particular reserve product exists for a period of at least 30 minutes to trigger the shortage pricing penalty factor for that reserve product. For example, if Real-Time SCED indicates a shortage of RTO wide primary reserve for an interval but the Intermediate-Term SCED forecasts that the reserve shortage does not extend beyond its first look ahead interval (15 minutes ahead of the Real-Time SCED

89 See OA Schedule 1 § 2.2(d).
90 152 FERC ¶ 61,218 (September 17, 2015).
91 *Id* at P 5.
92 155 FERC ¶ 61,276 (June 16, 2016).
93 *Id* at P 90.
94 *Id* at P 162.

interval), it is considered a transient shortage, and shortage pricing is not implemented. If Real-Time SCED indicates a shortage of RTO wide primary reserve for an interval and the Intermediate-Term SCED forecasts that the reserve shortage extends for at least two look ahead intervals (30 minutes ahead of the Real-Time SCED interval), shortage pricing is implemented. The rationale for including voltage reduction actions and manual load dump actions as triggers for shortage pricing is to reflect the fact that when dispatchers need to take these emergency actions to maintain reliability, the system is short reserves and prices should reflect that condition, even if the data does not show a shortage of reserves.[95]

PJM Compliance Filing on Shortage Pricing

On January 11, 2017, PJM filed proposed tariff revisions to comply with Order No. 825 and requested a simultaneous implementation date of February 1, 2018, for the settlement interval reforms and shortage pricing reforms.[96] In the January 11th Compliance Filing, PJM proposed to implement shortage pricing through the inclusion of the Reserve Penalty Factors in real time LMPs when the real time security constrained economic dispatch software determines that a primary reserve or synchronized reserve shortage exists on a five minute basis.[97]

Accuracy of Reserve Measurement

Under the new shortage pricing mechanism, the determination of shortage of synchronized and primary reserves by the real time SCED software is based on the measured and estimated levels of load, generation, interchange, demand response, and reserves. It also includes discretionary operator inputs to the ASO (Ancillary Service Optimizer) or SCED software. For the new shortage pricing mechanism to accurately reflect reserve shortage conditions, there needs to be accurate measurement of real-time reserves. That does not appear to be the case at present in PJM, but there does not appear to be any reason that PJM cannot implement that capability. Without very accurate measurement of reserves at minute by minute granularity, system operators cannot know with certainty that there is a shortage condition and therefore an appropriate trigger for five minute shortage pricing does not exist. The advantages of five minute shortage pricing are all implicitly based on the premise that the RTO knows accurately whether it is in a shortage condition. If PJM cannot demonstrate that it can accurately measure reserves at minute by minute granularity, it should not implement or continue five minute shortage pricing until it can demonstrate that capability.[98]

The Commission directed in the Final Rule that, to the extent an RTO/ISO needs to enhance its measurement capabilities to implement the shortage pricing requirement, it should propose to do so in its compliance filing.[99] PJM did not propose any enhancements to reserve measurement in the January 11th compliance filing.

The Market Monitor analyzed when shortage pricing would have been triggered in the first three months of 2017 and 2016 if the five minute shortage pricing rule had been in effect. There were two five minute intervals when both the MAD and the RTO synchronized reserves were less than the required levels in the first three months of 2017, compared to 15 such five minute intervals in the first three months of 2016. There were no five minute intervals when the MAD and RTO primary reserves were less than the required levels in the first three months of 2017 and 2016. Table 3-86 shows the number of intervals when five minute reserves were less than the required levels, the average shortage MW, the minimum shortage MW and the maximum shortage MW during the first three months of 2016 and 2017.

95 *See*, e.g., Scarcity and Shortage Pricing, Offer Mitigation and Offer Caps Workshop, Docket No. AD14-14-000, Transcript 29:21-30:14 (Oct. 28, 2014)

96 *See PJM Interconnection LLC*, Order No. 825 Compliance Filing, Docket No. ER17-775 (January 11, 2017) ("January 11th Compliance Filing").

97 PJM also plans to propose changes to the Operating Reserve Demand Curves used to trigger shortage pricing in a separate proceeding.

98 See Comments of the Independent Market Monitor for PJM, Docket No. RM15-24-000 (December 1, 2015) at 9.

99 155 FERC ¶ 61,276 at P 177 (June 16, 2016).

Table 3-86 Five minute reserve shortage statistics: January 1 through March 31, 2016 and 2017

	2016 (Jan - Mar)				2017 (Jan - Mar)			
Product	Number of Five Minute Shortage Intervals	Average of Shortage MW	Minimum Shortage MW	Maximum Shortage MW	Number of Five Minute Shortage Intervals	Average of Shortage MW	Minimum Shortage MW	Maximum Shortage MW
MAD Syncronized Reserve	15	51	9	186	2	52	21	83
RTO Synchronized Reserve	15	51	9	186	2	52	21	83
MAD Primary Reserve	0	NA	NA	NA	0	NA	NA	NA
RTO Primary Reserve	0	NA	NA	NA	0	NA	NA	NA

Table 3-87 shows the required synchronized reserves, the total synchronized reserves, and the shortage MW for the 2 five minute intervals when shortage pricing would have been triggered for synchronized reserve shortage in the first three months of 2017.

Table 3-87 Five minute intervals with synchronized reserve shortages: January 1 through March 31, 2017

Date and Time	Synchronized Reserve Requirement (MW)	Total Synchronized Reserves (MW)	Reserve Shortage (MW)
18-Feb-17 23:00	1,450	1,367	83
18-Feb-17 23:10	1,450	1,429	21

The accuracy of reserve measurement in PJM can be evaluated using historical data on performance during spinning events. The level of tier 1 biasing also reflects PJM dispatchers' estimate of the error in the measurement of tier 1 synchronized reserve. Both of these data sources provide insight into the accuracy of reserve measurement based on actual historical data.

Historical Performance During Spinning Events

Historical data on response from synchronized reserves during spinning events shows the accuracy of PJM reserve estimates. Synchronized reserves consist of tier 1 and tier 2 synchronized reserves that are procured to meet the RTO and Mid-Atlantic reserve requirements. Tier 1 synchronized reserve is comprised of all online resources following economic dispatch and able to ramp up from their current output in response to a synchronized reserve event.[100]

All resources that respond to spinning events are paid for their response. Table 3-88 shows the performance of tier 1 and tier 2 synchronized reserves during spinning events, declared in 2015 and 2016, that lasted at least 10 minutes. In 2015, tier 1 response MW shown in Table 3-88 were measured as the increase in MW from all resources as a response to the spinning event declaration, regardless of whether the units were part of the tier 1 MW estimate. Since the tier 1 response MW to spinning events included resources that were not part of the tier 1 MW estimate, the 2015 estimates for tier 1 response were greater than 100 percent. In 2016, PJM reports tier 1 response only from the units that were part of the estimated tier 1 MW.

Beginning in 2016, PJM started reporting the response to spinning events only from the units that were part of its tier 1 estimate MW. Table 3-88 shows that, in 2016, the tier 1 MW response percent was never greater than 85 percent, with an average tier 1 response of 75 percent.

If PJM is going to trigger shortage pricing based on shortage of synchronized reserves that is calculated based on current estimates, system operators will be relying on estimates of synchronized reserve MW that have historically been inaccurate.

100 See *2017 Quarterly State of the Market Report for PJM: January through March*, Section 10: Ancillary Service Markets at "Tier 1 Synchronized Reserve" for details on Tier 1 synchronized reserves.

Table 3-88 Performance of synchronized reserves during spinning events: March 3, 2015 through March 2017[101]

Spin Event (Date, Hour)	Duration (Minutes)	Tier 1 Estimate MW (Adjusted by DGP)	Tier 1 Response MW	Tier 2 Scheduled MW	Tier 2 Response MW	Tier 1 Response Percent	Tier 2 Response Percent
Mar 3, 2015 12	11	1,079.0	1,365.1	484.4	272.3	126.5%	56.2%
Mar 16, 2015 06	24	541.5	576.4	248.0	180.2	106.4%	72.7%
Mar 17, 2015 19	17	1,428.9	1,693.1	247.2	232.8	118.5%	94.2%
Mar 23, 2015 19	15	851.3	1,420.0	273.5	205.8	166.8%	75.2%
Jul 30, 2015 10	10	1,458.4	2,145.7	79.7	24.0	147.1%	30.1%
Jan 18, 2016 17	12	861.0	733.5	616.7	508.8	85.2%	82.5%
Feb 8, 2016 15	10	1,750.2	1,338.2	228.4	200.1	76.5%	87.6%
Apr 14, 2016 20	10	1,182.8	1,000.6	346.3	304.8	84.6%	88.0%
Jul 28, 2016 13	15	649.4	500.4	822.9	655.8	77.1%	79.7%
Nov 4, 2016 17	11	744.5	497.1	758.0	709.2	66.8%	93.6%
Dec 31, 2016 05	12	971.2	585.0	594.4	485.7	60.2%	81.7%
Mar 23, 2017 06	24	926.8	566.7	742.8	559.1	61.1%	75.3%

Tier 1 Synchronized Reserve Estimate Bias

The tier 1 synchronized reserve for a unit is measured as the lower of the available 10 minute ramp and the difference between the economic dispatch point and the economic maximum output. The total supply of tier 1 synchronized reserve MW available to the market solution is calculated as the sum of the individual units' tier 1 MW, with further adjustments. These adjustments include eliminating tier 1 MW from nuclear, wind, solar, energy storage, and hydro units, adjusting the available tier 1 MW from remaining units using a metric called Degree of Generator Performance (DGP) and using tier 1 estimate bias.[102] Tier 1 biasing occurs when PJM market operations manually modifies (increasing or decreasing) the tier 1 synchronized reserve estimate of the market solution. This forces the market clearing engine to clear more or less tier 2 synchronized reserve and nonsynchronized reserve to satisfy the synchronized reserve and primary reserve requirements. Tier 1 biasing reflects the operators' view on the available tier 1 MW in the system and a lack of confidence on the calculated estimates of tier 1 MW, thus forcing the market clearing engine to procure more or less synchronized reserves. Table 10-14 shows the average monthly biasing of tier 1 estimates in the Ancillary Service Optimizer (ASO), the tool used to procure reserves on an hourly basis, in 2015 and 2016.

The existence of tier MW biasing raises the possibility that under a five minute shortage pricing construct, shortage pricing penalty factors may be triggered or avoided not due to actual reserve levels, but by operators' discretionary decisions on the amount of available reserves. It is possible that the market engine's estimate of tier 1 MW, even after unit level adjustments such as DGP, may be enough to satisfy the reserve requirement, but an operator's biasing of the market engine's estimate may lead to triggering shortage pricing penalty factors. There are no rules in the PJM tariff or manuals regarding the use of tier 1 MW biasing. In a five minute shortage pricing construct, the need for explicit rules governing operator discretion regarding reserve estimates becomes critical. The IMM has recommended since 2012 that PJM explicitly define the rules for using tier 1 biasing and identify which rule permits it every time tier 1 synchronized reserve estimate biasing is used.

Generator Data used for Reserve Estimates

A potential source for the error in tier 1 MW is the use of economic dispatch point to calculate the available ramp limited MW in 10 minutes as opposed to the actual metered output from the generator for any 5 minute interval. The amount of tier 1 MW available from a resource may differ due to using the metered output from a unit versus the market clearing engine's estimate of the resource's output. PJM addressed this issue partially in 2015 by adjusting a resource's available 10 minute ramp with its DGP. The available tier 1 MW estimated by the market solution for each resource is adjusted by its DGP percent. PJM communicates to generation operators whose tier 1 MW is part of the market solution the latest estimate of units' tier 1 MW and units' current resource specific DGP.

101 Beginning January 2015, Degree of Generator Performance (DGP) was introduced as a metric to improve the accuracy of the tier 1 MW estimate used by the market solution.

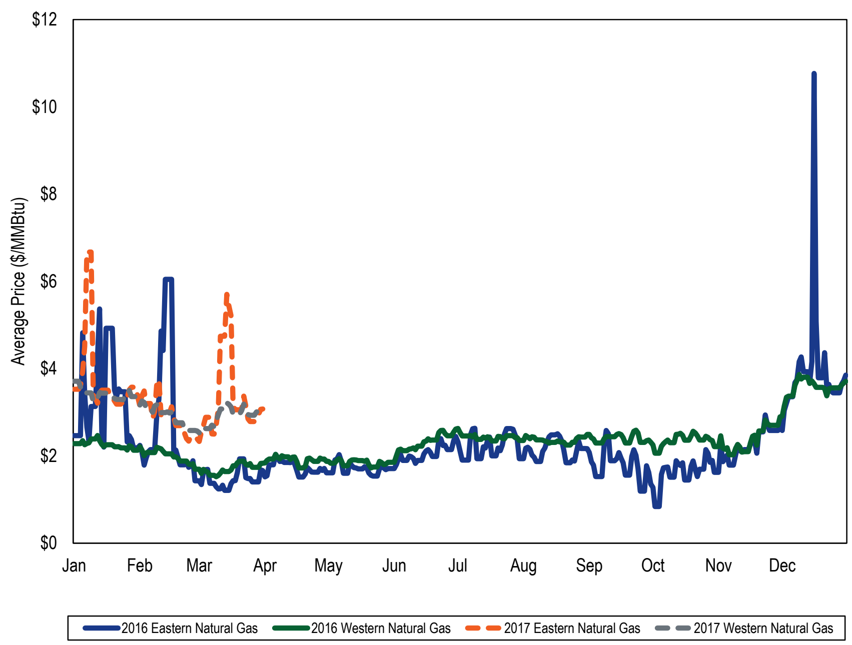
102 DGP measures how closely the unit has been following economic dispatch for the past 30 minutes.

PJM Cold Weather Operations 2017

Natural Gas Supply and Prices

As of March 31, 2017, gas fired generation was 35.9 percent (65,895.5 MW) of the total installed PJM capacity (183,593.6 MW).[103] The extreme cold weather conditions and the associated high demand for natural gas led to supply constraints on the gas transmission system which resulted in natural gas price volatility and interruptions to customers without firm transportation. Figure 3-53 shows the average daily price of delivered natural gas for eastern and western parts of PJM service territory in 2017 and 2016.[104]

Figure 3-53 Average daily delivered price for natural gas: January 2016 through March 2017 ($/MMBtu)



103 *2017 Quarterly State of the Market Report for PJM: January through March*, Section 5: Capacity Market, at Installed Capacity.

104 Eastern natural gas consists of the average of Texas Eastern M3, Transco Zone 6 non-NY, Transco Zone 6 NY and Transco Zone 5 daily fuel price indices. Western natural gas prices are the average of Dominion North Point, Columbia Appalachia and Chicago City gate daily fuel price indices.

During the first three months of 2015, 2016 and 2017, a number of interstate gas pipelines that supply fuel for generators in the PJM service territory issued restriction notices limiting the availability of nonfirm transportation services. These notices include warnings of operational flow orders (OFO) and actual OFOs. OFOs may, depending on the nature of the transportation service purchased, permit the pipelines to restrict the provision of gas to 24 hour ratable takes which means that hourly nominations must be the same for each of the 24 hours in the gas day, with penalties for deviating from the nominated quantities. Pipelines may also enforce strict balancing constraints which limit the ability of gas users, depending on the nature of the transportation service purchased, to deviate from the 24 hour ratable take and which may limit the ability of users to have access to unused gas.

Pipeline operators use restrictive and inflexible rules to manage the balance of supply and demand during extreme operating conditions. The independent operations of geographically overlapping pipelines during extreme conditions highlights the potential shortcomings of a gas pipeline network that relies on individual pipelines to manage the balancing of supply and demand. The independent operational restrictions imposed by pipelines and the impact on electric generators during extreme conditions suggests there may be potential benefits to creating an ISO/RTO structure to coordinate the supply of gas across pipelines and with the electric RTOs, or the creation of a gas supply coordination framework under existing electric ISO/RTOs.