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 for 2015, including market size, concentration, residual supply index, and price.[1] The MMU concludes that the PJM energy market results were competitive in 2015.

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

PJM markets are designed to promote competitive outcomes derived from the interaction of supply and demand in each of the PJM markets. Market design itself is the primary means of achieving and promoting competitive outcomes in PJM markets. One of the MMU's primary goals is to identify actual or potential market design flaws.[2] The approach to market power

1 Analysis of 2015 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."

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

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. These issues need to be addressed. There are issues related to the definition of gas costs includable in energy offers that need to be addressed. There are currently no market power mitigation rules in place that limit the ability to exercise market power when aggregate market conditions are tight. If market-based offer caps are raised, or if generators are allowed to modify offers hourly, market design must reflect appropriate incentives for competitive behavior and aggregate market power mitigation rules need to be developed.

Overview

Market Structure

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

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

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

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

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

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

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

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

  PJM average real-time load in 2015 decreased by 0.6 percent from 2014, from 89,099 MW to 88,594 MW. PJM average day-ahead demand in 2015, including DECs and up to congestion transactions, decreased by 21.5 percent from 2014, from 142,644 MW to 111,644 MW.

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.

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

Market Behavior

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

  In 2015, 15 control zones experienced congestion resulting from one or more constraints binding for 100 or more hours. The analysis of the application of the TPS test to local markets demonstrates that it is working successfully to identify pivotal owners when the market structure is noncompetitive and to ensure that owners are not subject to offer capping when the market structure is competitive. There are, however, identified issues with the application of market power mitigation to resources whose owners fail the TPS test that can result in the exercise of local market power. These issues need to be addressed.

- **Offer Capping for Reliability.** PJM also offer caps units that are committed for reliability reasons, specifically for black start service and reactive service. In the Day-Ahead Energy Market, for units committed for reliability reasons, offer-capped unit hours remained at 0.4 percent in 2014 and 2015. In the Real-Time Energy Market, for units committed for reliability reasons, offer-capped unit hours increased from 0.3 percent in 2014 to 0.4 percent in 2015.

- **Markup Index.** The markup index is a summary measure of participant offer behavior for individual marginal units. In the PJM Real-Time Energy Market, when using unadjusted cost offers, in 2015, 85.9 percent of marginal units had average dollar markups less than zero and had an average markup index less than zero. Using adjusted cost offers, in 2015, 47.1 percent of marginal units had average dollar markups less than zero and average markup index less than or equal to zero. Some marginal units did have substantial markups. Using unadjusted cost offers, 0.17 percent of offers had offer prices greater than $400 per MWh with average dollar markup of $56.87 per MWh.

  In the PJM Day-Ahead Energy Market, when using unadjusted cost offers, in 2015, 3.2 percent of marginal generating units had an average markup index less than or equal to zero. Using adjusted cost offers, in the 2015, 3.2 percent of marginal units had an average markup index less than or equal to zero.

- **Frequently Mitigated Units (FMU) and Associated Units (AU).** A new FMU rule became effective November 1, 2014, limiting the availability of FMU adders to units with net revenues less than unit going forward costs. There were no units eligible for an FMU or AU adder in 2015.

- **Virtual Offers and Bids.** Any market participant in the PJM Day-Ahead Energy Market can use increment offers, decrement bids, up to congestion transactions, import transactions and export transactions as financial instruments that do not require physical generation or load. The reduction in up to congestion transactions (UTC) continued, following a FERC order setting September 8, 2014, as the effective date for any uplift charges subsequently assigned to UTCs but there was an increase in up to congestion volume in December 2015, coincident with the expiration of the fifteen month resettlement period for the proceeding related to uplift charges for UTC transactions.[4] [5]

- **Generator Offers.** Generator offers are categorized as dispatchable and self scheduled. Units which are available for economic dispatch are dispatchable. Units which are self scheduled to generate fixed output are categorized as self scheduled. Units which are self scheduled at their economic minimum and are available for economic dispatch up to their economic maximum are categorized as self scheduled and dispatchable. Of all generator offers in 2015, 56.1 percent were offered as available for economic dispatch, 23.8 percent were offered as

4 148 FERC ¶ 61,144 (2014).
5 16 U.S.C. § 824e.

self scheduled, and 20.1 percent were offered as self scheduled and dispatchable.

Market Performance

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

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

  PJM Day-Ahead Energy Market prices decreased in 2015 compared to 2014. The load-weighted average day-ahead LMP was 31.5 percent lower in 2015 than in 2014, $36.73 per MWh versus $53.62 per MWh.

- **Components of LMP.** In the PJM Real-Time Energy Market, for 2015, 43.2 percent of the load-weighted LMP was the result of coal costs, 27.2 percent was the result of gas costs and 2.32 percent was the result of the cost of emission allowances.

  In the PJM Day-Ahead Energy Market for 2015, 29.6 percent of the load-weighted LMP was the result of the cost of coal, 22.5 percent was the result of DECs, 14.3 percent was the result of the cost of gas, 11.6 percent was the result of INCs, and 4.3 percent was the result of up to congestion transactions.

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

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

  In the PJM Day-Ahead Energy Market, marginal INCs, DECs and UTCs have zero markups. In 2015, the adjusted markup component of LMP resulting from generation resources was $0.78 per MWh or 2.1 percent of the PJM day-ahead load-weighted average LMP. The month of February had the highest adjusted markup component, $2.81 per MWh or 3.6 percent of the day-ahead load-weighted average LMP. In 2015, the highest hourly adjusted markup was $710.63.

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

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

Scarcity

- There were no shortage pricing events in 2015.

Recommendations

- The MMU recommends that PJM retain the $1,000 per MWh offer cap in the PJM energy market except when cost-based offers exceed $1,000 per MWh, and other existing rules that limit incentives to exercise market power. (Priority: High. First reported 1999. Status: Partially adopted, 1999.)

- The MMU recommends that the rules governing the application of the TPS test be clarified and documented. (Priority: High. First reported 2010. Status: Not adopted.)

- The MMU recommends, in order to ensure effective market power mitigation when the TPS test is failed, that markup be constant across price and cost offers, that there be at least one cost-based offer using the same fuel as the available price-based offer. (Priority: High. New recommendation. Status: Not adopted.)

- The MMU recommends that in order to ensure effective market power mitigation when the TPS test is failed, the operating parameters in the cost-based offer and the price-based parameter limited schedule (PLS) offer be at least as flexible as the operating parameters in the available non-PLS price-based offer, and that the price-MW pairs in the price based PLS offer be exactly equal to the price based non PLS offer. (Priority: High. New recommendation. Status: Not adopted.)
- The MMU recommends that PJM require all generating units to identify the fuel type associated with each of their offered schedules. (Priority: Low. First reported Q2, 2014. Status: Adopted in full, Q4, 2014.)
- The MMU recommends that under the Capacity Performance construct, PJM recognize the difference between operational parameters that indicate to PJM dispatchers what a unit is capable of during the operating day and the parameters that are used for capacity performance assessment as well as uplift payments. The parameters which determine non-performance charges and the amount of uplift payments to those generators should reflect the flexibility goals of the capacity performance construct. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that capacity performance resources and base capacity resources (during the June through September period) be held to the OEM operating parameters of the capacity market CONE reference resource for performance assessment and energy uplift payments. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that PJM remove non-specific fuel types such as “other” or “co-fire other” from the list of fuel types available for market participants to identify the fuel type associated with their price and cost schedules. (Priority: Medium. First reported Q2, 2015. Status: Not adopted.)
- The MMU recommends that a unit which is not capable of supplying energy consistent with its day-ahead offer should reflect an appropriate outage rather than indicating its availability to supply energy on an emergency basis. (Priority: Low. First reported 2009. Status: Not Adopted.)
- The MMU recommends that PJM explain how LMPs are calculated when demand response is marginal. The LMPs in excess of $1,800 per MWh on January 7, 2014, were potentially a result of the way in which PJM modeled zonal (not nodal) demand response as a marginal resource. (Priority: Low. First reported Q1, 2014. Status: Not Adopted.)
- The MMU recommends that PJM explicitly state its policy on the use of transmission penalty factors including the level of the penalty factors, the triggers for the use of the penalty factors, the appropriate line ratings to trigger the use of penalty factors, and when the transmission penalty factors will be used to set the shadow price. (Priority: Medium. New recommendation Status: Not adopted.)
- The MMU recommends that PJM routinely review all transmission facility ratings and any changes to those ratings to ensure that the normal, emergency and load dump ratings used in modeling the transmission system are accurate and reflect standard ratings practice. (Priority: Low. First reported 2013. Status: Partially adopted.)
- The MMU recommends that the definition of maximum emergency status in the tariff apply at all times rather than just during maximum emergency events.[6] (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

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

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.[7] There is currently no PJM documentation in the tariff or manuals explaining how hubs are created and how their definitions are changed.[8] (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that during hours when a generation bus shows a net withdrawal, the energy withdrawal be treated as load, not negative generation, for purposes of calculating load and load-weighted LMP. The MMU recommends that during hours when a load bus shows a net injection, the energy injection be treated as generation, not negative load, for purposes of calculating generation and load-weighted LMP. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM identify and collect data on available behind the meter generation resources, including nodal location information and relevant operating parameters. (Priority: Low. First reported 2013. Status: Partially adopted.)
- The MMU recommends that PJM continue to enhance its posting of market data to promote market efficiency. (Priority: Medium. First reported 2005. Status: Partially Adopted.)
- The MMU recommends the elimination of FMU and AU adders. FMU and AU adders no longer serve the purpose for which they were created and interfere with the efficient operation of PJM markets. (Priority: Medium. First reported 2012. Status: Adopted partially, Q4, 2014.)

7 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.

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

Conclusion

The MMU analyzed key elements of PJM energy market structure, participant conduct and market performance in 2015, including aggregate supply and demand, concentration ratios, three pivotal supplier test results, offer capping, participation in demand response programs, loads and prices.

Average PJM real-time generation increased by 4,490 MW, or 2.8 percent, in the summer of 2015 compared to the summer of 2014, and peak load increased by 2,023 MW. Market concentration levels remained moderate although there is high concentration in the intermediate and peaking segments of the supply curve which adds to concerns about market power when market conditions are tight. The relationship between supply and demand, regardless of the specific market, balanced by market concentration, is referred to as the supply-demand fundamentals or economic fundamentals. While the market structure does not guarantee competitive outcomes, overall the market structure of the PJM aggregate energy market remains reasonably competitive for most hours although aggregate market power does exist during high demand hours.

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

The three pivotal supplier test is applied by PJM on an ongoing basis for local energy markets in order to determine whether offer capping is required for transmission constraints.[9] This is a flexible, targeted real-time measure of market structure which replaced the offer capping of all units required to relieve a constraint. A generation owner or group of generation owners is pivotal for a local market if the output of the owners' generation facilities is required in order to relieve a transmission constraint. When a generation owner or group of owners is pivotal, it has the ability to increase the market price above the competitive level. The three pivotal supplier test explicitly incorporates the impact of excess supply and implicitly accounts for the impact of the price elasticity of demand in the market power tests. The result of the introduction of the three pivotal supplier test was to limit offer capping to times when the local market structure was noncompetitive and specific owners had structural market power. The analysis of the application of the three pivotal supplier test demonstrates that it is working for most hours to exempt owners when the local market structure is competitive and to require offer capping of owners when the local market structure is noncompetitive.

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

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

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

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

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

demand hours in 2014 or 2015. This is evidence of generally competitive behavior and competitive market outcomes, although the behavior of some participants during the high demand periods in the first quarter is consistent with economic withholding. Given the structure of the energy market which can permit the exercise of aggregate market power at times of high demand, the tighter market conditions and the change in some participants' behavior are sources of concern in the energy market and provide a reason to use cost as the sole basis for hourly changes in offers or offers greater than $1,000 per MWh. The MMU concludes that the PJM energy market results were competitive in 2015.

Market Structure

Market Concentration

Analysis of supply curve segments of the PJM energy market in 2015 indicates moderate concentration in the base load segment, but high concentration in the intermediate and peaking segments.[10] 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.

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 2015 although there are issues with the application of market power mitigation for resources whose owners fail the TPS test.

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. 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.[11]

PJM HHI Results

Calculations for hourly HHI indicate that by the FERC standards, the PJM energy market during 2015 was moderately concentrated (Table 3-2).

Table 3-2 PJM hourly energy market HHI: 2014 and 2015[12]

	Hourly Market HHI (2014)	Hourly Market HHI (2015)
Average	1153	1096
Minimum	930	879
Maximum	1468	1468
Highest market share (One hour)	29%	31%
Average of the highest hourly market share	21%	21%
# Hours	8,760	8,760
# 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 2014 and 2015. The PJM energy market was moderately concentrated overall with moderate concentration in the baseload segment, but high concentration in the intermediate and peaking segments.

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

11 77 FERC ¶ 61,263, pp. 64-70 (1996), *"Inquiry Concerning the Commission's Merger Policy under the Federal Power Act: Policy Statement."*

12 This analysis includes all hours in 2014 and 2015, regardless of congestion.

Table 3-3 PJM hourly energy market HHI (By supply segment): 2014 and 2015

	2014			2015		
	Minimum	Average	Maximum	Minimum	Average	Maximum
Base	1031	1182	1484	988	1132	1487
Intermediate	795	1919	7307	603	1863	6375
Peak	643	5959	10000	716	5728	10000

Figure 3-1 shows the number of units in the baseload, intermediate and peaking segments by fuel source in 2015.

Figure 3-1 Fuel source distribution in unit segments: 2015[13]

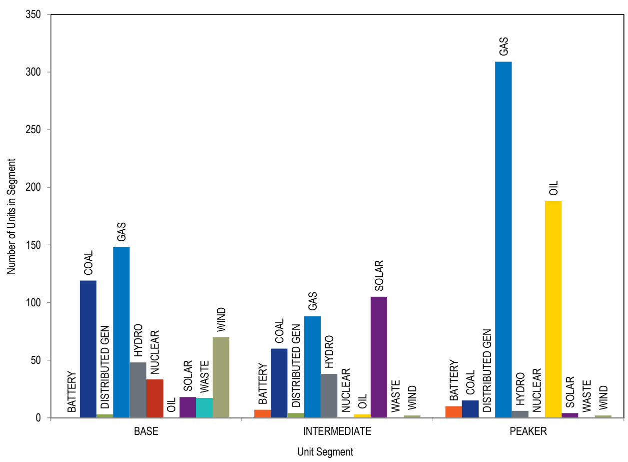
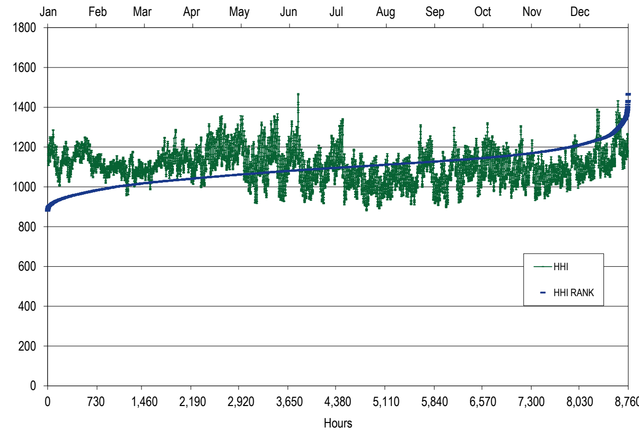


Figure 3-2 presents the hourly HHI values in chronological order and an HHI duration curve for 2015.

Figure 3-2 PJM hourly energy market HHI: 2015



Ownership of Marginal Resources

Table 3-4 shows the contribution to real-time, load-weighted LMP by individual marginal resource owner.[14] The contribution of each marginal resource to price at each load bus is calculated for each five-minute interval of 2015, and summed by the parent company that offers the marginal resource into the Real-Time Energy Market. The results show that in 2015, the offers of one company contributed 19.0 percent of the real-time, load-weighted PJM system LMP and that the offers of the top four companies contributed 55.2 percent of the real-time, load-weighted, average PJM system LMP. During 2014, the offers of one company contributed 17.1 percent of the real time, load-weighted PJM system LMP and offers of the top four companies contributed 56.6 percent of the real-time, load-weighted, average PJM system LMP.

Table 3-4 Marginal unit contribution to PJM real-time, load-weighted LMP (By parent company): 2014 and 2015

2014		2015	
Company	Percent of Price	Company	Percent of Price
1	17.1%	1	19.0%
2	17.1%	2	15.6%
3	12.6%	3	10.9%
4	9.8%	4	9.8%
5	7.9%	5	8.7%
6	5.8%	6	8.4%
7	5.6%	7	4.4%
8	4.8%	8	4.0%
9	3.1%	9	2.6%
Other (62 companies)	16.3%	Other (62 companies)	16.7%

13 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.

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

Table 3-5 shows the contribution to day-ahead, load-weighted LMP by individual marginal resource owners.[15] 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 2015, the offers of one company contributed 12.5 percent of the day-ahead, load-weighted PJM system LMP and that the offers of the top four companies contributed 39.3 percent of the day-ahead, load-weighted, average PJM system LMP. In 2014, the offers of one company contributed 10.0 percent of the day-ahead, load-weighted PJM system LMP and offers of the top four companies contributed 32.9 percent of the day-ahead, load-weighted, average PJM system LMP.

Table 3-5 Marginal resource contribution to PJM day-ahead, load-weighted LMP (By parent company): 2014 and 2015

2014		2015	
Company	Percent of Price	Company	Percent of Price
1	10.0%	1	12.5%
2	9.0%	2	11.3%
3	7.5%	3	9.7%
4	6.3%	4	5.9%
5	5.7%	5	5.2%
6	5.3%	6	5.1%
7	4.8%	7	4.0%
8	3.9%	8	3.7%
9	2.8%	9	3.6%
Other (154 companies)	44.8%	Other (155 companies)	39.0%

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 2015, coal units were 51.74 percent and natural gas units were 35.52 percent of marginal resources. In 2014, coal units were 52.90 percent and natural gas units were 35.81 percent of the total marginal resources. In 2015, 75.26 percent of the wind marginal units had negative offer prices, 20.93 percent had zero offer prices and 3.81 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.[16]

Table 3-6 Type of fuel used (By real-time marginal units): 2011 through 2015

	Year				
Type/Fuel	2011	2012	2013	2014	2015
Coal	68.73%	58.84%	56.94%	52.90%	51.74%
Gas	25.84%	30.35%	34.72%	35.81%	35.52%
Oil	2.24%	6.00%	3.27%	7.44%	8.99%
Wind	2.36%	4.19%	4.76%	3.29%	3.27%
Other	0.00%	0.47%	0.20%	0.43%	0.39%
Municipal Waste	0.62%	0.13%	0.07%	0.05%	0.06%
Uranium	0.01%	0.02%	0.02%	0.04%	0.03%
Emergency DR	0.00%	0.00%	0.02%	0.04%	0.00%
Interface	0.20%	0.00%	0.00%	0.00%	0.00%

Table 3-7 shows the type and fuel type where relevant, of marginal resources in the Day-Ahead Energy Market. In 2015, up to congestion transactions were 76.14 percent of marginal resources. Up to congestion transactions were 91.05 percent of marginal resources in 2014.

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

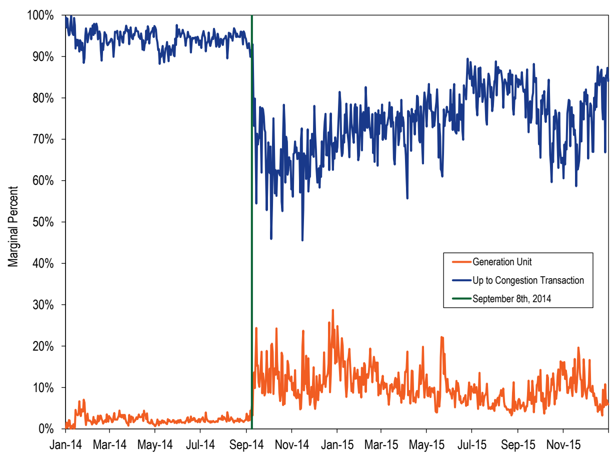
16 Prior to April 1, 2015, for the generation units that are capable of using multiple fuel types, PJM did not require the participants to disclose the fuel type associated with their offer schedule. For these units, the cleared offer schedules on a given day were compared to the cost associated with 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: 2011 through 2015

Type/Fuel	2011	2012	2013	2014	2015
Up to Congestion Transaction	73.40%	88.40%	96.44%	91.05%	76.14%
DEC	12.38%	4.30%	1.27%	3.28%	8.87%
Coal	4.66%	2.31%	0.78%	2.03%	5.50%
INC	7.54%	3.81%	1.05%	2.28%	5.08%
Gas	1.54%	1.04%	0.36%	1.16%	3.31%
Oil	0.00%	0.00%	0.00%	0.05%	0.56%
Dispatchable Transaction	0.17%	0.07%	0.05%	0.08%	0.26%
Wind	0.07%	0.03%	0.04%	0.05%	0.12%
Nuclear	0.00%	0.00%	0.00%	0.00%	0.11%
Price Sensitive Demand	0.23%	0.04%	0.01%	0.01%	0.02%
Other	0.00%	0.00%	0.00%	0.00%	0.01%
Total	100.00%	100.00%	100.00%	100.00%	100.00%

Figure 3-3 shows, for the Day-Ahead Market in 2014 and 2015, the daily proportion of marginal resources that were up to congestion transaction and/or generation units. The percentage 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.[17] The percentage of marginal up to congestion transaction decreased and that of generation units increased.

Figure 3-3 Day-ahead marginal up to congestion transaction and generation units: 2014 and 2015

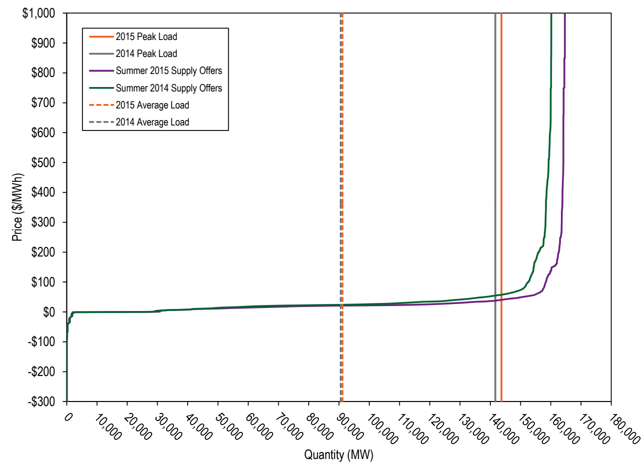


Supply

Supply includes physical generation and imports and virtual transactions.

Figure 3-4 shows the average PJM aggregate real-time generation supply curves by offer price, peak load and average load for the summer of 2014 and 2015. Total average PJM aggregate real-time generation supply increased by 4,490 MW, or 2.8 percent, in the summer of 2015 from an average maximum of 160,190 MW in the summer of 2014 to 164,680 MW in the summer of 2015.

Figure 3-4 Average PJM aggregate real-time generation supply curves by offer price: Summer of 2014 and 2015



Energy Production by Fuel Source

Table 3-8 shows PJM generation by fuel source in GWh for 2014 and 2015. In 2015, generation from coal units decreased 17.8 percent and generation from natural gas units increased 28.4 percent compared to 2014.[18]

17 See 18 CFR § 385.213 (2014).

18 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.

Table 3-8 PJM generation (By fuel source (GWh)): 2014 and 2015[19 20]

	2014		2015		Change in
	GWh	Percent	GWh	Percent	Output
Coal	349,961.9	43.3%	287,634.7	36.6%	(17.8%)
Standard Coal	346,053.6	42.8%	284,414.0	36.2%	(17.8%)
Waste Coal	3,908.3	0.5%	3,220.7	0.4%	(17.6%)
Nuclear	277,635.6	34.4%	279,106.5	35.5%	0.5%
Gas	144,140.0	17.8%	184,083.2	23.4%	27.7%
Natural Gas	140,463.4	17.4%	180,307.8	22.9%	28.4%
Landfill Gas	2,369.0	0.3%	2,404.2	0.3%	1.5%
Biomass Gas	1,307.6	0.2%	1,371.2	0.2%	4.9%
Hydroelectric	14,394.3	1.8%	13,066.6	1.7%	(9.2%)
Pumped Storage	7,138.7	0.9%	5,946.1	0.8%	(16.7%)
Run of River	7,255.5	0.9%	7,120.5	0.9%	(1.9%)
Wind	15,540.5	1.9%	16,609.7	2.1%	6.9%
Waste	4,833.3	0.6%	4,729.7	0.6%	(2.1%)
Solid Waste	4,251.4	0.5%	4,175.4	0.5%	(1.8%)
Miscellaneous	581.8	0.1%	554.3	0.1%	(4.7%)
Oil	1,073.2	0.1%	917.6	0.1%	(14.5%)
Heavy Oil	464.3	0.1%	610.9	0.1%	31.6%
Light Oil	511.8	0.1%	247.8	0.0%	(51.6%)
Diesel	75.3	0.0%	56.9	0.0%	(24.4%)
Kerosene	21.7	0.0%	1.8	0.0%	(91.6%)
Jet Oil	0.0	0.0%	0.0	0.0%	NA
Solar, Net Energy Metering	400.9	0.0%	542.7	0.0%	35.4%
Battery	6.5	0.0%	7.6	0.0%	17.5%
Total	807,986.2	100.0%	786,698.2	100.0%	(2.6%)

Table 3-9 Monthly PJM generation (By fuel source (GWh)): 2015

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Coal	32,666.4	33,315.4	25,902.0	18,265.1	21,619.0	24,258.9	27,534.0	26,910.5	24,461.1	18,003.1	17,816.0	16,883.2	287,634.7
Standard Coal	32,309.5	32,992.8	25,589.6	18,068.7	21,363.2	24,000.4	27,330.1	26,618.6	24,193.8	17,830.3	17,533.9	16,583.0	284,414.0
Waste Coal	356.8	322.6	312.4	196.4	255.8	258.5	203.8	291.9	267.3	172.8	282.1	300.1	3,220.7
Nuclear	25,881.8	21,994.5	22,290.8	20,346.7	22,641.7	23,823.5	24,119.1	24,889.5	23,390.5	22,736.5	21,790.8	25,201.0	279,106.5
Gas	13,911.6	13,267.0	14,462.9	12,115.7	14,289.8	16,629.6	20,057.0	18,852.0	16,618.1	13,769.3	14,458.8	15,651.5	184,083.2
Natural Gas	13,567.7	12,957.9	14,155.0	11,840.9	13,978.2	16,281.6	19,690.6	18,495.6	16,304.3	13,509.3	14,176.6	15,350.0	180,307.8
Landfill Gas	213.5	188.1	208.4	200.0	212.1	196.1	208.0	201.6	187.9	194.6	193.7	200.1	2,404.2
Biomass Gas	130.4	121.0	99.5	74.7	99.5	151.9	158.3	154.8	125.9	65.4	88.5	101.4	1,371.2
Hydroelectric	953.9	763.3	1,152.3	1,379.6	1,025.2	1,310.5	1,624.2	1,105.5	758.8	754.7	1,023.2	1,215.4	13,066.6
Pumped Storage	398.8	388.7	344.7	331.4	504.2	729.1	842.9	823.6	546.7	292.4	337.3	406.3	5,946.1
Run of River	555.1	374.6	807.6	1,048.2	521.0	581.4	781.3	281.9	212.0	462.4	685.9	809.1	7,120.5
Wind	1,664.4	1,511.1	1,701.2	1,642.0	1,209.1	955.2	639.4	623.9	846.5	1,756.2	2,023.3	2,037.4	16,609.7
Waste	400.9	324.0	357.1	378.6	384.8	407.5	412.9	430.7	383.9	392.8	426.5	429.9	4,729.7
Solid Waste	347.8	279.7	308.0	335.4	347.2	370.7	369.8	380.9	332.1	350.0	371.4	382.3	4,175.4
Miscellaneous	53.1	44.3	49.1	43.2	37.5	36.8	43.2	49.8	51.8	42.8	55.1	47.6	554.3
Oil	81.0	408.6	13.1	5.3	43.8	45.7	158.0	69.9	26.7	11.9	39.5	35.2	938.6
Heavy Oil	64.3	315.0	0.0	0.0	0.0	29.3	143.3	57.6	0.0	0.0	0.0	1.4	610.9
Light Oil	13.7	58.8	10.3	5.2	40.0	12.6	11.9	8.6	18.9	6.9	33.8	27.2	247.8
Diesel	2.9	33.4	2.5	0.2	3.8	3.8	1.8	1.6	4.8	1.0	0.6	0.6	56.9
Kerosene	0.1	1.4	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.8
Jet Oil	0.0	0.0	0.0	0.0	0.0	0.0	1.0	2.0	3.0	4.0	5.0	6.0	21.0
Solar, Net Energy Metering	23.3	32.1	38.7	53.1	61.9	53.0	61.2	63.1	50.4	45.9	34.4	25.6	542.7
Battery	0.4	0.4	0.5	0.4	0.5	0.6	0.6	0.5	0.8	0.8	1.1	1.1	7.6
Total	75,583.7	71,616.3	65,918.5	54,186.4	61,275.7	67,484.5	74,606.4	72,945.6	66,536.7	57,471.3	57,613.8	61,480.5	786,719.2

19 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.

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

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

Average offered real-time generation increased by 4,490 MW, or 2.8 percent, in the summer months of 2015 from an average maximum of 160,190 MW in the summer months of 2014 to 164,680 MW in the summer months of 2015.[21]

In 2015, 3,041.2 MW of new capacity were added to PJM. This new generation was more than offset by the deactivation of and 9,897.2 MW of generation retired (108 units).

PJM average real-time generation in 2015 decreased by 2.5 percent from 2014, from 90,894 MW to 88,628 MW.[22]

PJM average real-time supply including imports decreased by 2.0 percent in 2015 from 2014, from 96,295 MW to 94,329 MW.

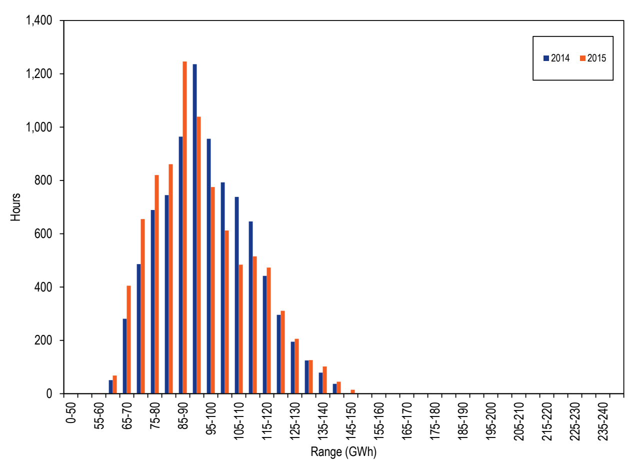
In the PJM Real-Time Energy Market, there are three types of supply offers:

- **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.
- **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 3-5 shows the hourly distribution of PJM real-time generation plus imports for 2014 and 2015.

Figure 3-5 Distribution of PJM real-time generation plus imports: 2014 and 2015[23]



21 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.

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

23 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 16-year period from 2000 through 2015.[24]

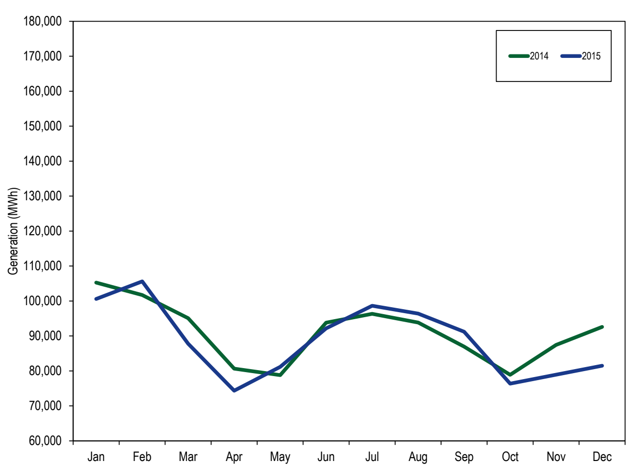
Table 3-10 PJM real-time average hourly generation and real-time average hourly generation plus average hourly imports: 2000 through 2015

	PJM Real-Time Supply (MWh)				Year-to-Year Change			
	Generation		Generation Plus Imports		Generation		Generation Plus Imports	
	Generation	Standard Deviation	Supply	Standard Deviation	Generation	Standard Deviation	Supply	Standard Deviation
2000	30,301	4,980	33,256	5,456	NA	NA	NA	NA
2001	29,553	4,937	32,552	5,285	(2.5%)	(0.9%)	(2.1%)	(3.1%)
2002	34,928	7,535	38,535	7,751	18.2%	52.6%	18.4%	46.7%
2003	36,628	6,165	40,205	6,162	4.9%	(18.2%)	4.3%	(20.5%)
2004	51,068	13,790	55,781	14,652	39.4%	123.7%	38.7%	137.8%
2005	81,127	15,452	86,353	15,981	58.9%	12.0%	54.8%	9.1%
2006	82,780	13,709	86,978	14,402	2.0%	(11.3%)	0.7%	(9.9%)
2007	85,860	14,018	90,351	14,763	3.7%	2.3%	3.9%	2.5%
2008	83,476	13,787	88,899	14,256	(2.8%)	(1.7%)	(1.6%)	(3.4%)
2009	78,026	13,647	83,058	14,140	(6.5%)	(1.0%)	(6.6%)	(0.8%)
2010	82,585	15,556	87,386	16,227	5.8%	14.0%	5.2%	14.8%
2011	85,775	15,932	90,511	16,759	3.9%	2.4%	3.6%	3.3%
2012	88,708	15,701	94,083	16,505	3.4%	(1.4%)	3.9%	(1.5%)
2013	89,769	15,012	94,833	15,878	1.2%	(4.4%)	0.8%	(3.8%)
2014	90,894	15,151	96,295	16,199	1.3%	0.9%	1.5%	2.0%
2015	88,628	16,118	94,329	17,312	(2.5%)	6.4%	(2.0%)	6.9%

PJM Real-Time, Monthly Average Generation

Figure 3-6 compares the real-time, monthly average hourly generation in 2014 and 2015.

Figure 3-6 PJM real-time average monthly hourly generation: 2014 through 2015



24 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.

Day-Ahead Supply

PJM average day-ahead supply in 2015, including INCs and up to congestion transactions, decreased by 21.7 percent from 2014, from 146,672 MW to 114,889 MW.

PJM average day-ahead supply in 2015, including INCs, up to congestion transactions, and imports, decreased by 21.3 percent from 2014, from 148,906 MW to 117,146 MW. The reduction in PJM day-ahead supply was a result of a decrease in in UTCs beginning in September 2014 based on a FERC order setting September 8, 2014, as the effective date for any uplift charges subsequently assigned to UTCs.[25]

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-

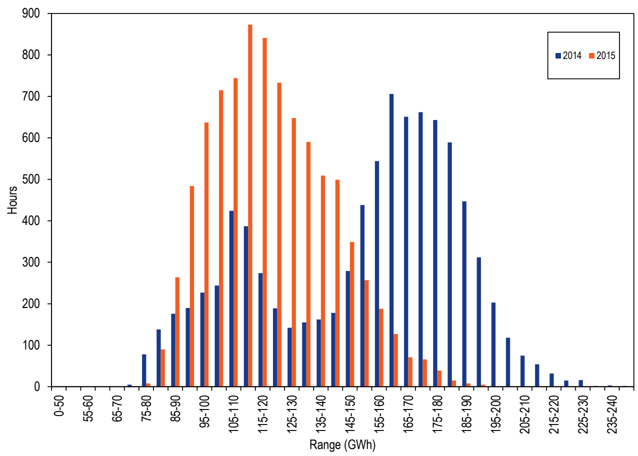
25 148 FERC ¶ 61,144 (2014).

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 3-7 shows the hourly distribution of PJM day-ahead supply, including increment offers, up to congestion transactions, and imports for 2014 and 2015. The shift in the results was a result of the decrease in in UTCs beginning in September 2014.

Figure 3-7 Distribution of PJM day-ahead supply plus imports: 2014 and 2015[26]



PJM Day-Ahead, Average Supply

Table 3-11 presents summary day-ahead supply statistics for each year of the 16-year period from 2000 through 2015.[27]

Table 3-11 PJM day-ahead average hourly supply and day-ahead average hourly supply plus average hourly imports: 2000 through 2015

	PJM Day-Ahead Supply (MWh)				Year-to-Year Change			
	Supply		Supply Plus Imports		Supply		Supply Plus Imports	
	Supply	Standard Deviation	Supply	Standard Deviation	Supply	Standard Deviation	Supply	Standard Deviation
2000	27,135	4,858	27,589	4,895	NA	NA	NA	NA
2001	26,762	4,595	27,497	4,664	(1.4%)	(5.4%)	(0.3%)	(4.7%)
2002	31,434	10,007	31,982	10,015	17.5%	117.8%	16.3%	114.7%
2003	40,642	8,292	41,183	8,287	29.3%	(17.1%)	28.8%	(17.3%)
2004	62,755	17,141	63,654	17,362	54.4%	106.7%	54.6%	109.5%
2005	94,438	17,204	96,449	17,462	50.5%	0.4%	51.5%	0.6%
2006	100,056	16,543	102,164	16,559	5.9%	(3.8%)	5.9%	(5.2%)
2007	108,707	16,549	111,023	16,729	8.6%	0.0%	8.7%	1.0%
2008	105,485	15,994	107,885	16,136	(3.0%)	(3.4%)	(2.8%)	(3.5%)
2009	97,388	16,364	100,022	16,397	(7.7%)	2.3%	(7.3%)	1.6%
2010	107,307	21,655	110,026	21,837	10.2%	32.3%	10.0%	33.2%
2011	117,130	20,977	119,501	21,259	9.2%	(3.1%)	8.6%	(2.6%)
2012	134,479	17,905	136,903	18,080	14.8%	(14.6%)	14.6%	(15.0%)
2013	148,323	18,783	150,595	18,978	10.3%	4.9%	10.0%	5.0%
2014	146,672	33,145	148,906	33,346	(1.1%)	76.5%	(1.1%)	75.7%
2015	114,889	19,164	117,146	19,405	(21.7%)	(42.2%)	(21.3%)	(41.8%)

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

PJM Day-Ahead, Monthly Average Supply

Figure 3-8 compares the day-ahead, monthly average hourly supply, including increment offers and up to congestion transactions, in 2014 and 2015. The reduction in PJM day-ahead supply was a result of a decrease in in UTCs beginning in September 2014 based on a FERC order setting September 8, 2014, as the effective date for any uplift charges subsequently assigned to UTCs.[28]

Figure 3-8 PJM day-ahead monthly average hourly supply: 2014 through 2015

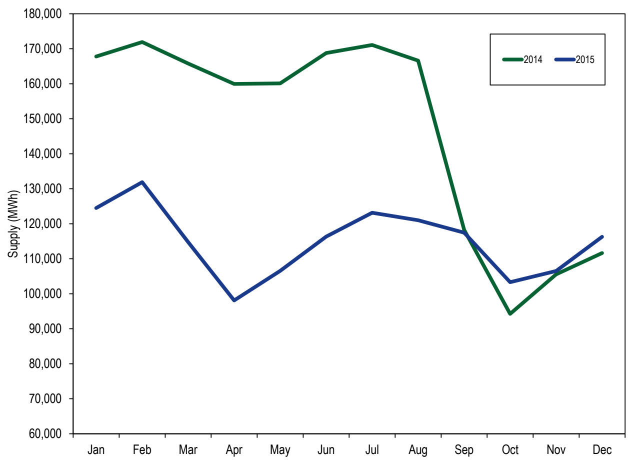


Table 3-12 presents summary statistics for 2014 and 2015, for day-ahead and real-time supply. The last two columns of Table 3-12 are the day-ahead supply minus the real-time supply. The first of these columns is the total day-ahead supply less the total real-time supply and the second of these columns is the total physical day-ahead generation less the total physical real-time generation. In 2015, up-to congestion transactions were 16.4 percent of the total day-ahead supply compared to 33.2 percent in 2014.

Figure 3-9 shows the average hourly cleared volumes of day-ahead supply and real-time supply for 2015. The day-ahead supply consists of day-ahead generation, imports, cleared increments and up to congestion transactions. The real-time generation includes generation and imports.

Real-Time and Day-Ahead Supply

Table 3-12 Day-ahead and real-time supply (MWh): 2014 and 2015

		Day Ahead					Real Time		Day Ahead Less Real Time	
		Generation	Cleared INC	Up-to Congestion	Imports	Total Supply	Generation	Total Supply	Total Supply	Total Generation
Average	2014	93,687	3,492	49,492	2,235	148,906	90,895	96,295	52,611	2,793
	2015	90,959	4,675	19,255	2,257	117,146	88,628	94,329	22,817	2,331
Median	2014	92,635	3,382	61,234	2,233	158,207	89,449	94,703	63,505	3,186
	2015	88,874	4,599	18,435	2,215	114,964	85,989	91,318	23,647	2,885
Standard Deviation	2014	15,992	917	26,785	446	33,346	15,150	16,198	17,148	842
	2015	17,341	791	5,230	503	19,405	16,118	17,312	2,093	1,223
Peak Average	2014	103,462	4,002	49,854	2,411	159,729	99,634	105,731	53,998	3,828
	2015	100,528	4,765	20,779	2,416	128,487	96,809	103,211	25,275	3,718
Peak Median	2014	102,051	3,995	61,834	2,386	171,568	98,610	104,536	67,032	3,441
	2015	97,480	4,714	19,777	2,428	126,042	93,304	99,485	26,558	4,176
Peak Standard Deviation	2014	13,014	830	26,086	407	32,171	12,742	13,578	18,593	272
	2015	14,481	715	5,336	504	16,480	14,438	15,379	1,102	43
Off-Peak Average	2014	85,167	3,048	49,176	2,081	139,473	83,277	88,071	51,402	1,890
	2015	82,242	4,594	17,867	2,112	106,815	81,176	86,238	20,578	1,067
Off-Peak Median	2014	83,792	2,959	60,803	2,035	151,999	81,614	86,212	65,787	2,178
	2015	79,108	4,485	17,186	2,059	103,524	78,333	82,832	20,692	775
Off-Peak Standard Deviation	2014	13,235	742	27,377	421	31,435	12,785	13,607	17,828	449
	2015	14,976	847	4,722	455	15,757	13,787	14,832	925	1,189

28 148 FERC ¶ 61,144 (2014).

Figure 3-9 Day-ahead and real-time supply (Average hourly volumes): 2015

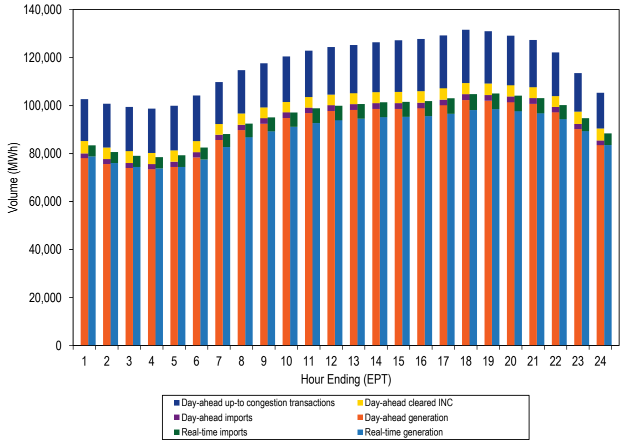


Figure 3-10 shows the difference between the day-ahead and real-time average daily supply in 2014 through 2015.

Figure 3-10 Difference between day-ahead and real-time supply (Average daily volumes): 2014 through 2015

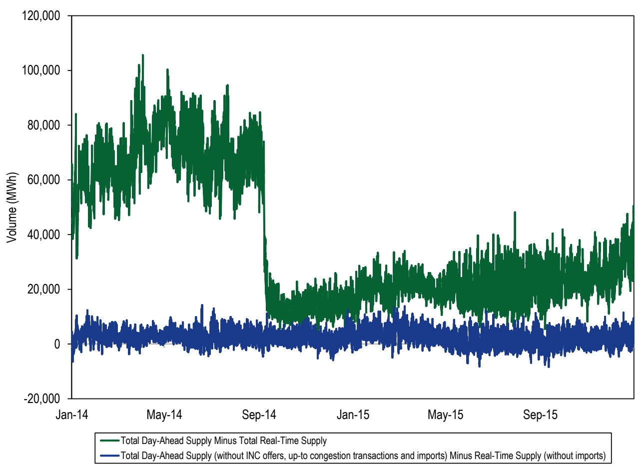
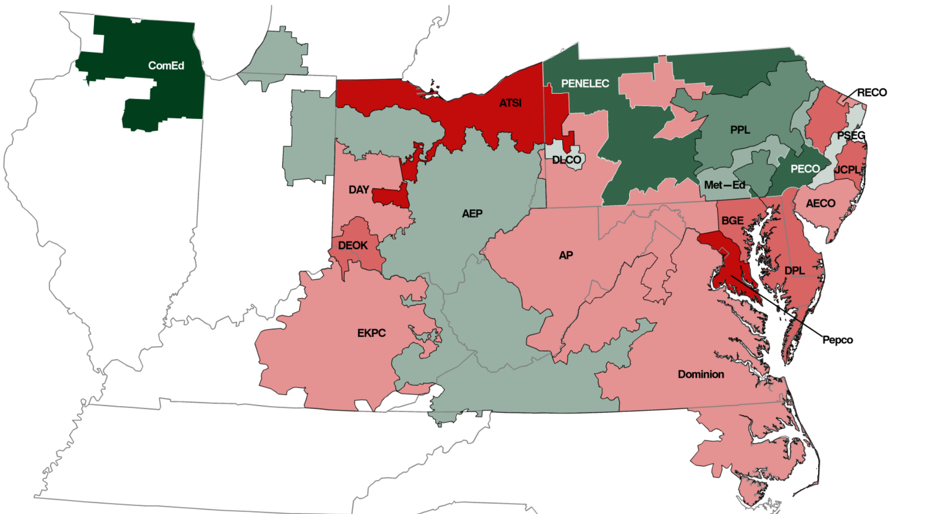


Figure 3-11 shows the difference between the PJM real-time generation and real-time load by zone in 2015. Table 3-13 shows the difference between the PJM real-time generation and real-time load by zone in 2014 and 2015. Figure 3-11 is color coded on a scale on which red shades represent zones that have 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.

Figure 3-11 Map of PJM real-time generation less real-time load by zone: 2015[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	(3,608)	ComEd	21,540	DPL	(8,462)	PENELEC	17,357
AEP	10,612	DAY	(2,977)	EKPC	(2,652)	Pepco	(16,285)
AP	(3,635)	DEOK	(6,684)	JCPL	(7,600)	PPL	9,548
ATSI	(14,301)	DLCO	1,802	Met-Ed	5,405	PSEG	2,189
BGE	(8,009)	Dominion	(6,885)	PECO	14,138	RECO	(1,193)

Table 3-13 PJM real-time generation less real-time load by zone (GWh): 2014 and 2015

	Zonal Generation and Load (GWh)					
	2014			2015		
Zone	Generation	Load	Net	Generation	Load	Net
AECO	3,296.0	10,252.7	(6,956.6)	6,208.5	10,436.1	(4,227.6)
AEP	148,249.6	128,957.3	19,292.3	134,241.8	126,850.3	7,391.5
AP	46,089.7	48,355.4	(2,265.7)	44,431.4	48,207.0	(3,775.5)
ATSI	53,453.7	67,730.8	(14,277.1)	48,684.8	66,651.7	(17,966.9)
BGE	21,368.7	31,967.1	(10,598.4)	22,244.0	32,072.4	(9,828.5)
ComEd	126,274.9	97,683.0	28,591.9	125,658.7	95,365.1	30,293.6
DAY	14,342.8	17,011.2	(2,668.4)	13,661.1	16,884.0	(3,223.0)
DEOK	19,823.2	27,019.7	(7,196.5)	17,115.3	26,843.3	(9,727.9)
DLCO	17,735.1	14,411.1	3,324.0	16,604.9	14,167.8	2,437.1
Dominion	82,444.7	95,306.3	(12,861.6)	88,335.4	95,891.2	(7,555.8)
DPL	7,514.5	18,379.3	(10,864.7)	7,479.8	18,578.0	(11,098.2)
EKPC	10,384.4	12,803.0	(2,418.6)	8,603.7	12,180.9	(3,577.2)
JCPL	12,976.5	22,758.7	(9,782.2)	14,415.1	23,172.8	(8,757.7)
Met-Ed	21,625.3	15,082.6	6,542.7	22,081.5	15,208.6	6,872.9
PECO	60,038.1	39,803.7	20,234.4	60,404.2	40,307.4	20,096.8
PENELEC	44,805.9	17,274.8	27,531.1	37,224.2	17,105.7	20,118.5
Pepco	11,775.6	30,446.7	(18,671.1)	8,868.6	30,398.5	(21,529.9)
PPL	49,135.5	40,885.7	8,249.8	52,504.7	40,586.7	11,918.0
PSEG	44,896.7	42,883.6	2,013.1	47,617.7	43,664.3	3,953.4
RECO	0.0	1,492.7	(1,492.7)	0.0	1,521.2	(1,521.2)

Demand

Demand includes physical load and exports and virtual transactions.

Peak Demand

The PJM system load reflects the entire RTO. The PJM energy market includes the Real-Time Energy Market and the Day-Ahead Energy Market. In this section, demand refers to physical load and exports and in the Day-Ahead Energy Market also includes virtual transactions, which include decrement bids and up to congestion transactions.

The PJM system real-time peak load for 2015 was 143,697 MW in the HE 17 on July 28, 2015, which was 2,023 MW, or 1.4 percent, higher than the peak load for 2014, which was 141,673 MW in the HE 17 on June 17, 2014.

Table 3-14 shows the peak loads for 1999 through 2015.

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>.

Table 3-14 Actual PJM footprint peak loads: 1999 to 2015[30]

	Date	Hour Ending (EPT)	PJM Load (MW)	Annual Change (MW)	Annual Change (%)
1999	Fri, July 30	17	120,227	NA	NA
2000	Wed, August 09	17	114,036	(6,191)	(5.1%)
2001	Wed, August 08	17	128,535	14,499	12.7%
2002	Thu, August 01	17	130,159	1,625	1.3%
2003	Thu, August 21	17	126,259	(3,900)	(3.0%)
2004	Wed, June 09	17	120,218	(6,041)	(4.8%)
2005	Tue, July 26	16	133,761	13,543	11.3%
2006	Wed, August 02	17	144,644	10,883	8.1%
2007	Wed, August 08	16	139,428	(5,216)	(3.6%)
2008	Mon, June 09	17	130,100	(9,328)	(6.7%)
2009	Mon, August 10	17	126,798	(3,302)	(2.5%)
2010	Tue, July 06	17	136,460	9,662	7.6%
2011	Thu, July 21	17	158,016	21,556	15.8%
2012	Tue, July 17	17	154,344	(3,672)	(2.3%)
2013	Thu, July 18	17	157,508	3,165	2.1%
2014	Tue, June 17	17	141,673	(15,835)	(10.1%)
2015	Tue, July 28	17	143,697	2,023	1.4%

Figure 3-12 shows the peak loads for 1999 through 2015.

Figure 3-12 PJM footprint calendar year peak loads: 1999 to 2015

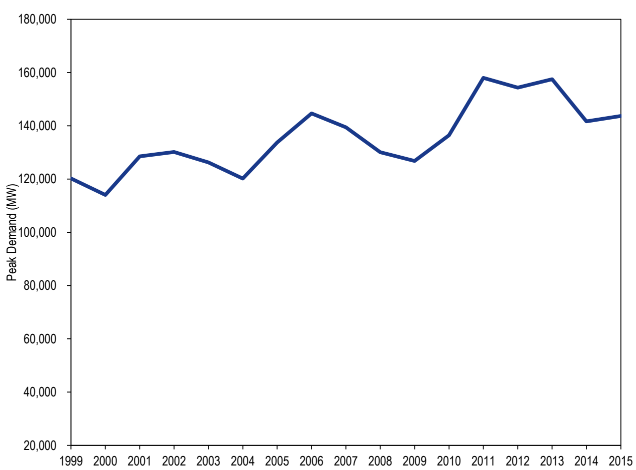
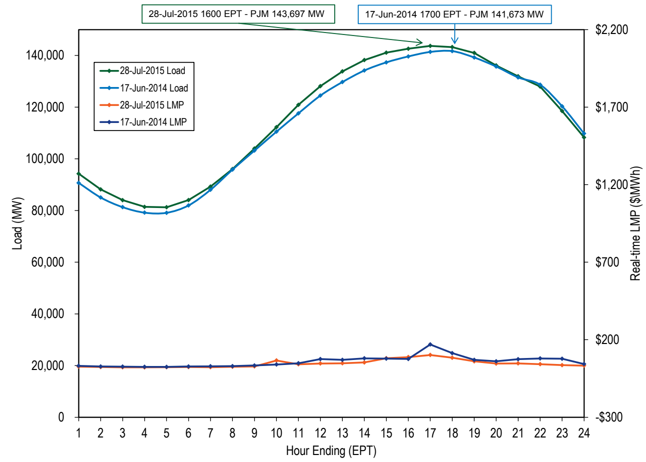


Figure 3-13 compares the peak load days during 2014 and 2015. The average hourly real-time LMP peaked at $101.40 on July 28, 2015 and peaked at $169.33 on June 17, 2014.

Figure 3-13 PJM peak-load comparison: Tuesday, July 28, 2015 and Tuesday, June 17, 2014



Real-Time Demand

PJM average real-time load in 2015 decreased by 0.6 percent from 2014, from 89,099 MW to 88,594 MW.[31]

PJM average real-time demand in 2015 decreased 1.9 percent from 2014, from 94,471 MW to 92,665 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.

PJM Real-Time Demand Duration

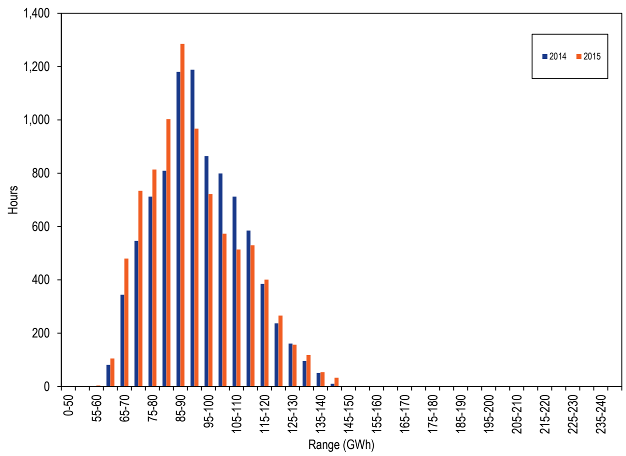
Figure 3-14 shows the hourly distribution of PJM real-time load plus exports for 2014 and 2015.[32]

30 Peak loads shown are eMTR 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>.

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

32 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>.

Figure 3-14 Distribution of PJM real-time accounting load plus exports: 2014 and 2015[33]



PJM Real-Time, Average Load

Table 3-15 presents summary real-time demand statistics for the 18-year period 1998 to 2015. 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.[34]

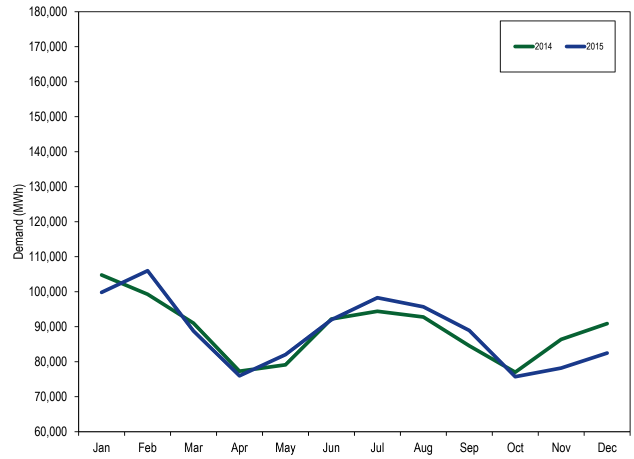
Table 3-15 PJM real-time average hourly load and real-time average hourly load plus average hourly exports: 1998 through 2015[35]

	PJM Real-Time Demand (MWh)				Year-to-Year Change			
	Load		Load Plus Exports		Load		Load Plus Exports	
	Load	Standard Deviation	Demand	Standard Deviation	Load	Standard Deviation	Demand	Standard Deviation
1998	28,578	5,511	28,578	5,511	NA	NA	NA	NA
1999	29,641	5,955	29,641	5,955	3.7%	8.1%	3.7%	8.1%
2000	30,113	5,529	31,341	5,728	1.6%	(7.2%)	5.7%	(3.8%)
2001	30,297	5,873	32,165	5,564	0.6%	6.2%	2.6%	(2.9%)
2002	35,776	7,976	37,676	8,145	18.1%	35.8%	17.1%	46.4%
2003	37,395	6,834	39,380	6,716	4.5%	(14.3%)	4.5%	(17.5%)
2004	49,963	13,004	54,953	14,947	33.6%	90.3%	39.5%	122.6%
2005	78,150	16,296	85,301	16,546	56.4%	25.3%	55.2%	10.7%
2006	79,471	14,534	85,696	15,133	1.7%	(10.8%)	0.5%	(8.5%)
2007	81,681	14,618	87,897	15,199	2.8%	0.6%	2.6%	0.4%
2008	79,515	13,758	86,306	14,322	(2.7%)	(5.9%)	(1.8%)	(5.8%)
2009	76,034	13,260	81,227	13,792	(4.4%)	(3.6%)	(5.9%)	(3.7%)
2010	79,611	15,504	85,518	15,904	4.7%	16.9%	5.3%	15.3%
2011	82,541	16,156	88,466	16,313	3.7%	4.2%	3.4%	2.6%
2012	87,011	16,212	92,135	16,052	5.4%	0.3%	4.1%	(1.6%)
2013	88,332	15,489	92,879	15,418	1.5%	(4.5%)	0.8%	(3.9%)
2014	89,099	15,763	94,471	15,677	0.9%	1.8%	1.7%	1.7%
2015	88,594	16,663	92,665	16,784	(0.6%)	5.7%	(1.9%)	7.1%

PJM Real-Time, Monthly Average Load

Figure 3-15 compares the real-time, monthly average hourly loads in 2014 and 2015.

Figure 3-15 PJM real-time monthly average hourly load: 2014 and 2015



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

34 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 excludes losses prior to June 1 and includes losses after June 1.

35 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 load is significantly affected by temperature. Figure 3-16 and Table 3-16 compare the PJM monthly heating and cooling degree days in 2014 and 2015.[36] Heating degree days decreased 1.9 percent and cooling degree days increased 19.7 percent from 2014 to 2015.

Figure 3-16 PJM heating and cooling degree days: 2014 and 2015

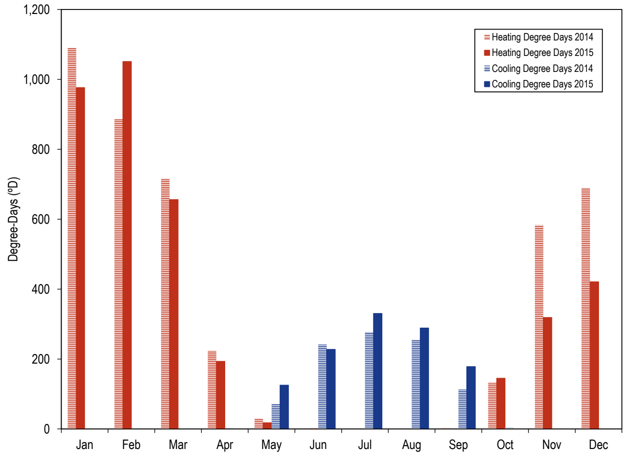


Table 3-16 PJM heating and cooling degree days: 2014 and 2015

	2014		2015		Percent Change	
	Heating Degree Days	Cooling Degree Days	Heating Degree Days	Cooling Degree Days	Heating Degree Days	Cooling Degree Days
Jan	1,090	0	977	0	(10.4%)	0.0%
Feb	887	0	1,051	0	18.5%	0.0%
Mar	716	0	656	0	(8.4%)	0.0%
Apr	224	2	193	0	(13.8%)	0.0%
May	30	71	18	125	(40.3%)	75.8%
Jun	0	242	1	228	0.0%	(5.8%)
Jul	0	277	0	330	0.0%	19.2%
Aug	0	256	0	289	0.0%	12.9%
Sep	3	113	0	179	(100.0%)	57.7%
Oct	133	4	145	0	8.9%	0.0%
Nov	583	0	319	0	(45.3%)	0.0%
Dec	690	0	421	0	(39.0%)	0.0%
Total	4,358	966	3,781	1,151	(1.9%)	19.7%

Day-Ahead Demand

PJM average day-ahead demand in 2015, including DECs and up to congestion transactions, decreased by 21.5 percent from 2014, from 142,251 MW to 111,644 MW.

PJM average day-ahead demand in 2015, including DECs, up to congestion transactions, and exports, decreased by 21.3 percent from 2014, from 146,120 MW to 115,007 MW.

The reduction in PJM day-ahead demand was a result of a substantial decrease in in UTCs beginning in September 2014 based on a FERC order setting September 8, 2014, as the effective date for any uplift charges subsequently assigned to UTCs.[37]

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

- **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

36 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 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.

37 148 FERC ¶ 61,144 (2014).

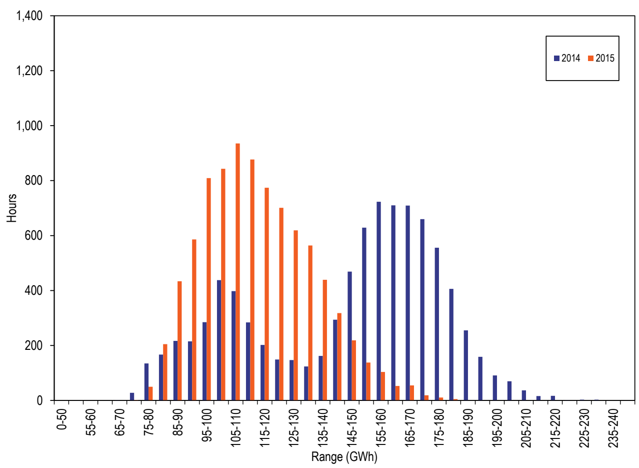
Energy Market and the PJM Real-Time Energy Market, so an export energy transaction approved in the Day-Ahead Energy Market will not physically flow in real time unless it is also submitted through the Real-Time Energy Market scheduling process.

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

PJM Day-Ahead Demand Duration

Figure 3-17 shows the hourly distribution of PJM day-ahead demand, including decrement bids, up to congestion transactions, and exports for 2014 and 2015. The shift in day-ahead demand was the result of a reduction in UTC activity.

Figure 3-17 Distribution of PJM day-ahead demand plus exports: 2014 and 2015[38]



PJM Day-Ahead, Average Demand

Table 3-17 presents summary day-ahead demand statistics for each year of the 16-year period 2000 to 2015.[39]

Table 3-17 PJM day-ahead average demand and day-ahead average hourly demand plus average hourly exports: 2000 through 2015

	PJM Day-Ahead Demand (MWh)				Year-to-Year Change			
	Demand		Demand Plus Exports		Demand		Demand Plus Exports	
	Demand	Standard Deviation	Demand	Standard Deviation	Demand	Standard Deviation	Demand	Standard Deviation
2000	33,039	6,852	33,411	6,757	NA	NA	NA	NA
2001	33,370	6,562	33,757	6,431	1.0%	(4.2%)	1.0%	(4.8%)
2002	42,305	10,161	42,413	10,208	26.8%	54.9%	25.6%	58.7%
2003	44,674	7,841	44,807	7,811	5.6%	(22.8%)	5.6%	(23.5%)
2004	62,101	16,654	63,455	17,730	39.0%	112.4%	41.6%	127.0%
2005	93,534	17,643	96,447	17,952	50.6%	5.9%	52.0%	1.3%
2006	98,527	16,723	101,592	17,197	5.3%	(5.2%)	5.3%	(4.2%)
2007	105,503	16,686	108,932	17,030	7.1%	(0.2%)	7.2%	(1.0%)
2008	101,903	15,871	105,368	16,119	(3.4%)	(4.9%)	(3.3%)	(5.3%)
2009	94,941	15,869	98,094	15,999	(6.8%)	(0.0%)	(6.9%)	(0.7%)
2010	103,937	21,358	108,069	21,640	9.5%	34.6%	10.2%	35.3%
2011	113,866	20,708	117,681	20,929	9.6%	(3.0%)	8.9%	(3.3%)
2012	131,612	17,421	134,947	17,527	15.6%	(15.9%)	14.7%	(16.3%)
2013	144,858	18,489	148,132	18,570	10.1%	6.1%	9.8%	5.9%
2014	142,251	32,664	146,120	32,671	(1.8%)	76.7%	(1.4%)	75.9%
2015	111,644	18,715	115,007	18,867	(21.5%)	(42.7%)	(21.3%)	(42.3%)

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

39 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.

PJM Day-Ahead, Monthly Average Demand

Figure 3-18 compares the day-ahead, monthly average hourly demand, including decrement bids and up to congestion transactions, in 2014 and 2015. The reduction in PJM day-ahead demand was a result of a decrease in UTCs beginning in September 2014 based on a FERC order setting September 8, 2014, as the effective date for any uplift charges subsequently assigned to UTCs.[40]

Figure 3-18 PJM day-ahead monthly average hourly demand: 2014 and 2015

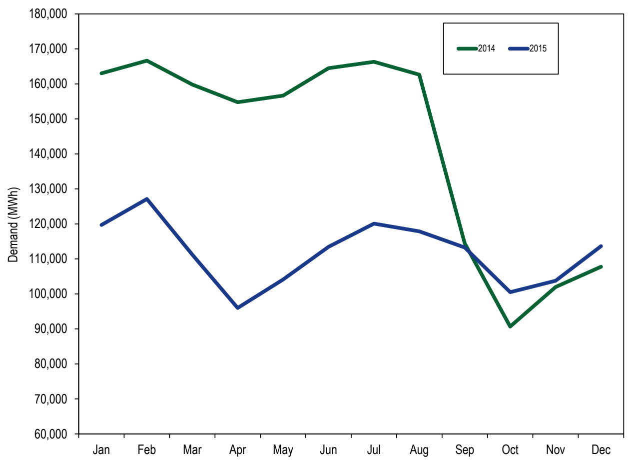


Table 3-18 presents summary statistics for 2014 and 2015 day-ahead and real-time demand. The last two columns of Table 3-18 are the day-ahead demand minus the real-time demand. The first such column is the total day-ahead demand less the total real-time demand and the second such column is the total physical day-ahead load (fixed demand plus price sensitive demand) less the physical real-time load.

Figure 3-19 shows the average hourly cleared volumes of day-ahead demand and real-time demand for 2015. 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.

Real-Time and Day-Ahead Demand

Table 3-18 Cleared day-ahead and real-time demand (MWh): 2014 and 2015

		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	2014	85,004	1,212	6,592	49,443	3,869	146,120	89,093	94,465	51,654	37,439
	2015	85,171	3,167	4,051	19,255	3,363	115,007	88,594	92,665	22,342	66,252
Median	2014	83,546	1,203	6,354	61,205	3,770	155,243	87,436	92,950	62,293	25,143
	2015	82,980	3,214	3,821	18,435	3,213	112,811	85,997	89,783	23,028	62,969
Standard Deviation	2014	14,908	167	1,490	26,804	926	32,671	15,758	15,672	16,999	(1,242)
	2015	15,726	553	1,311	5,230	926	18,867	16,663	16,784	2,083	14,580
Peak Average	2014	94,326	1,283	7,408	49,835	3,865	156,718	98,451	103,651	53,067	45,385
	2015	94,077	3,438	4,428	20,779	3,327	126,049	97,416	101,318	24,731	72,684
Peak Median	2014	92,878	1,277	7,259	61,833	3,783	168,393	97,036	102,457	65,935	31,101
	2015	90,912	3,481	4,213	19,777	3,138	123,781	94,086	97,727	26,054	68,032
Peak Standard Deviation	2014	12,179	161	1,414	26,095	932	31,555	13,159	13,123	18,432	(5,273)
	2015	13,302	512	1,241	5,336	969	16,062	14,529	14,908	1,153	13,376
Off-Peak Average	2014	76,890	1,149	5,883	49,102	3,872	136,896	80,948	86,470	50,425	30,522
	2015	77,057	2,921	3,706	17,867	3,396	104,947	80,574	84,798	20,149	60,425
Off-Peak Median	2014	75,237	1,142	5,658	60,731	3,762	149,205	79,055	84,726	64,478	14,576
	2015	74,197	2,924	3,445	17,186	3,283	101,821	77,587	81,544	20,277	57,310
Off-Peak Standard Deviation	2014	12,047	147	1,152	27,404	922	30,776	13,083	13,121	17,655	(4,572)
	2015	13,166	466	1,277	4,722	883	15,263	14,253	14,346	917	13,335

40 148 FERC ¶ 61,144 (2014).

Figure 3-19 Day-ahead and real-time demand (Average hourly volumes): 2015

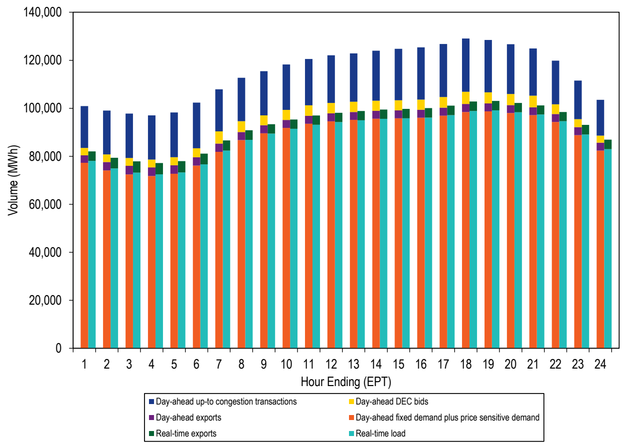
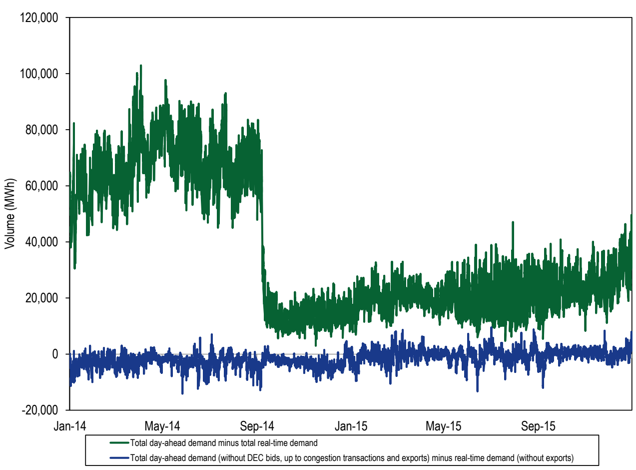


Figure 3-20 shows the difference between the day-ahead and real-time average daily demand in 2014 and 2015. The substantial decrease in UTC MW in September 2014, which resulted in a corresponding decrease in day-ahead demand, was a result of a FERC order setting September 8, 2014, as the effective date for any uplift charges assigned to UTCs.[41]

Figure 3-20 Difference between day-ahead and real-time demand (Average daily volumes): 2014 and 2015



41 148 FERC ¶ 61,144 (2014).

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 market power mitigation to situations where market structure is not competitive and thus where market design alone cannot mitigate market power.

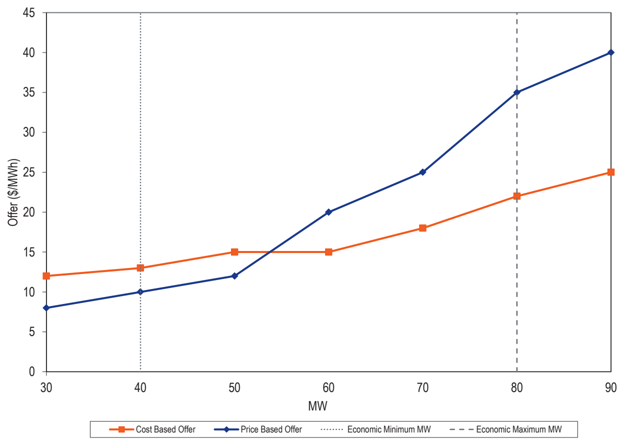
The analysis of the application of the three pivotal supplier test demonstrates that it is working for most hours to exempt owners when the local market structure is competitive and to offer cap owners when the local market structure is noncompetitive. However, there are some issues with the application 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. 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 3-21 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

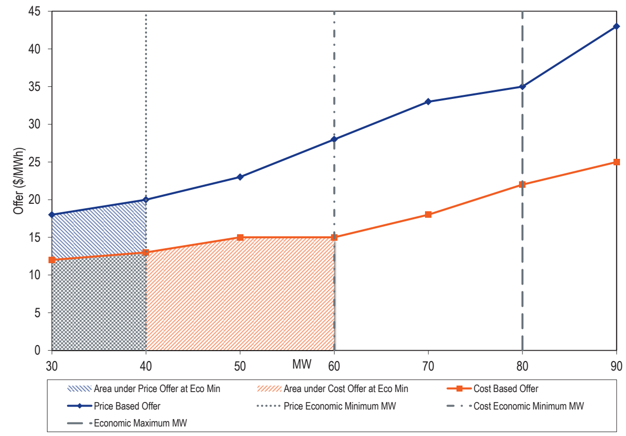
TPS test would be committed on its price-based offer even though the price-based offer is higher than cost at higher output levels and includes positive markups, inconsistent with the explicit goal of local market power mitigation.

Figure 3-21 Offers with varying markups at different MW output levels



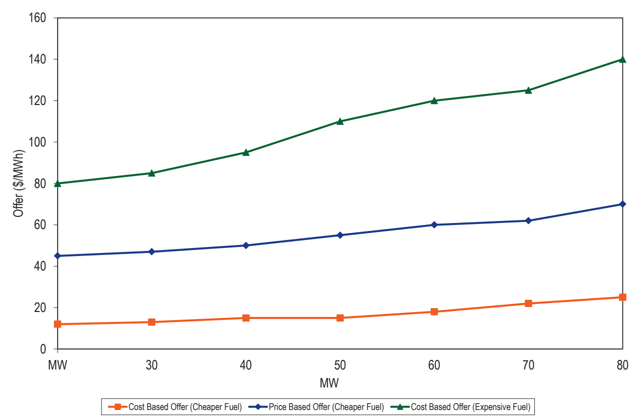
Offering a different economic minimum MW level, different minimum run times, different start up and notification times on the cost-based and price-based offers can also be used to avoid mitigation. For example, a unit may offer its price-based offer with a negative markup, but have a longer minimum run time (MRT) on the price-based offer. 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 because the total cost of commitment (calculated as a product of MW and the offer in dollars per MWh plus the startup and no-load cost) can be lower on price-based offer at the lower economic minimum level compared to cost-based offer at a higher economic minimum level. Figure 3-22 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. The cost of commitment (area under the curve) 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 non-competitive level even after the resource owner fails the TPS test.

Figure 3-22 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 3-23 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 3-23 Dual fuel unit offers



These issues can be solved by simple rule changes.[42] 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

42 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).

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 3-19. The offer capping percentages shown in Table 3-19 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 3-19 Offer-capping statistics – energy only: 2011 to 2015

	Real Time		Day Ahead	
Year	Unit Hours Capped	MW Capped	Unit Hours Capped	MW Capped
2011	0.6%	0.2%	0.0%	0.0%
2012	0.8%	0.4%	0.1%	0.1%
2013	0.4%	0.2%	0.1%	0.0%
2014	0.5%	0.2%	0.2%	0.1%
2015	0.4%	0.2%	0.2%	0.1%

Table 3-20 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 2011 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 and 2015 because higher LMPs (in the first three 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 3-19.

Table 3-20 Offer-capping statistics for energy and reliability: 2011 through 2015

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

Table 3-21 shows the offer capping percentages for units committed to provide black start service and reactive support. The data in Table 3-21 is the difference between the offer cap percentages shown in Table 3-20 and Table 3-19.

Table 3-21 Offer-capping statistics for reliability: 2011 through 2015

	Real Time		Day Ahead	
Year	Unit Hours Capped	MW Capped	Unit Hours Capped	MW Capped
2011	0.1%	0.0%	0.0%	0.0%
2012	0.9%	0.6%	0.8%	0.4%
2013	2.5%	2.2%	3.1%	2.1%
2014	0.3%	0.3%	0.4%	0.3%
2015	0.4%	0.6%	0.4%	0.6%

Table 3-22 presents data on the frequency with which units were offer capped in 2014 and 2015, for failing the TPS test to provide energy for constraint relief in the Real-Time Energy Market. Table 3-22 shows that seven units were offer capped for 90 percent or more of their run hours in 2015 compared to one in 2014.

Table 3-22 Real-time offer-capped unit statistics: 2014 through 2015

		Offer-Capped Hours					
Run Hours Offer-Capped, Percent Greater Than Or Equal To:	Year	Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
90%	2015	2	0	0	0	1	4
	2014	1	0	0	0	0	0
80% and < 90%	2015	0	1	1	0	0	6
	2014	2	0	0	3	0	0
75% and < 80%	2015	0	0	0	0	0	3
	2014	1	0	0	0	1	0
70% and < 75%	2015	0	0	0	0	0	4
	2014	0	0	0	0	0	0
60% and < 70%	2015	0	0	0	1	0	9
	2014	0	0	0	1	7	5
50% and < 60%	2015	0	0	0	0	1	9
	2014	0	0	0	0	3	6
25% and < 50%	2015	0	0	0	0	1	26
	2014	0	3	1	1	10	45
10% and < 25%	2015	0	0	5	2	5	34
	2014	0	1	4	1	8	56

TPS Test Statistics

In 2015, the AECO, AEP, AP, ATSI, BGE, ComEd, DEOK, DLCO, Dominion, DPL, MetEd, PECO, PENELEC, PPL, and PSEG control zones experienced congestion resulting from one or more constraints binding for 100 or more hours or resulting from an interface constraint. The DAY, EKPC, JCPL, Pepco, and RECO control zones did not have constraints binding for 100 or more hours in 2015. Table 3-23 shows that BGE, ComEd, PPL and PSEG were the control zones that experienced congestion resulting from one or more constraints binding for 100 or more hours or resulting from an interface constraint that was binding for one or more hours in every year in 2009 through 2015.

Table 3-23 Numbers of hours when control zones experienced congestion resulting from one or more constraints binding for 100 or more hours or from an interface constraint: 2009 through 2015

	2009	2010	2011	2012	2013	2014	2015
AECO	149	172	234	NA	208	NA	394
AEP	1,045	1,192	2,253	NA	2,611	2,710	1,274
AP	1,877	4,765	1,924	206	NA	170	167
ATSI	157	NA	NA	208	270	489	242
BGE	152	470	1,041	2,970	1,760	6,255	9,601
ComEd	1,212	2,080	1,134	4,554	5,143	4,119	5,878
DEOK	NA	NA	NA	109	NA	NA	112
DLCO	156	475	206	209	NA	223	617
Dominion	468	905	1,506	1,020	944	NA	1,172
DPL	NA	122	NA	1,542	639	3,071	2,066
Met-Ed	NA	180	162	NA	NA	NA	222
PECO	247	NA	788	386	732	1,953	895
PENELEC	103	284	NA	NA	176	4,281	1,683
Pepco	149	1	NA	143	245	41	NA
PPL	176	118	40	350	452	148	266
PSEG	303	549	1,107	913	3,021	4,688	2,665

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 2015.[43] 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.

Table 3-24 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 3-24 Three pivotal supplier test details for interface constraints: 2015

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
5004/5005 Interface	Peak	385	477	15	2	13
	Off Peak	424	574	15	2	13
AEP - DOM	Peak	436	297	8	0	8
	Off Peak	249	274	7	0	7
AP South	Peak	341	423	11	2	10
	Off Peak	276	438	11	1	10
Bedington - Black Oak	Peak	174	233	14	2	12
	Off Peak	172	218	12	2	10
Central	Peak	945	918	14	2	12
	Off Peak	667	754	13	3	10
Eastern	Peak	837	740	13	0	13
	Off Peak	897	763	12	4	9
Western	Peak	617	633	13	1	12
	Off Peak	476	508	12	1	11

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. 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 3-25 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.

43 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 3-25 Summary of three pivotal supplier tests applied for interface constraints: 2015

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
5004/5005 Interface	Peak	1,817	58	3%	38	2%	66%
	Off Peak	1,801	107	6%	59	3%	55%
AEP - DOM	Peak	148	21	14%	18	12%	86%
	Off Peak	110	11	10%	4	4%	36%
AP South	Peak	118	6	5%	3	3%	50%
	Off Peak	65	10	15%	2	3%	20%
Bedington - Black Oak	Peak	1,595	59	4%	30	2%	51%
	Off Peak	984	33	3%	13	1%	39%
Central	Peak	198	3	2%	3	2%	100%
	Off Peak	102	1	1%	0	0%	0%
Eastern	Peak	86	3	3%	3	3%	100%
	Off Peak	14	0	0%	0	0%	0%
Western	Peak	429	9	2%	5	1%	56%
	Off Peak	116	0	0%	0	0%	0%

Parameter Limited Schedules

All capacity resources in PJM are required to submit at least one cost-based offer. All cost-based offers are parameter limited in accordance with the Parameter Limited Schedule (PLS) matrix or to the level of a prior approved exception.[44] All capacity resources that choose to offer price-based schedules are required to make available at least one price-based parameter limited schedule. This schedule is to be used by PJM for committing generation resources when a maximum emergency generation alert is declared.

During the extreme cold weather conditions in the first three months of 2015, 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, ratio of economic maximum MW to economic minimum MW). When pipelines issue critical notices and enforce ratable take requirements, generators may 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, to avoid deviations from the hourly nominated quantity.

Key parameters like startup and notification time were not limited by the PLS matrix in 2015. 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.

Currently, there are no specific rules in the PJM tariff or manuals that specify the limits on 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 units offering inflexible operating parameters to extract uplift payments. However, a generator can use a price based PLS offer but include a higher markup than the price based non-PLS schedule. The result would that it is more expensive to commit a unit on the price based PLS, thus permitting the exercise of market power using the PLS offer. This defeats the purpose of having the 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.

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

Parameter Limited Schedules under Capacity Performance

Beginning in delivery year 2016-2017, 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. In its order on Capacity Performance, the Commission determined that 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.[45] The Commission found that it is unjust and unreasonable to not provide uplift payments to resources with parameters based on non-physical constraints.[46] The Commission directed PJM to submit tariff language to establish a process through which resources that operate outside the defined unit-specific parameter limits can justify such operation and therefore remain eligible for make-whole payments.[47]

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 Order's determination on parameters is not consistent with that goal. By permitting generation owners to establish unit parameters based on non-physical 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. 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 would increase energy market uplift payments substantially. Uplift costs are unpredictable, opaque and unhedgeable. 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 those generators should reflect the flexibility goals of the capacity performance construct.

The MMU recommends that resources be held to the OEM operating parameters of the capacity market CONE reference resource for performance assessment and energy uplift payments. This solution creates the incentives for flexibility and preserves, to the extent possible, the incentives to follow PJM's dispatch instructions during tight 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 tight 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

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

will be exempt from non-performance 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 tight conditions. If any of the less flexible resources need to be dispatched down by PJM for reliability reasons, they would be exempt from non-performance charges.

Such an approach is consistent with the Commission's no excuses policy for non-performance 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 non-performance 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 non-performance. 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

The markup index is a summary measure of participant offer behavior or conduct for individual marginal units. The markup index for each marginal unit is calculated as (Price – Cost)/Price.[48] 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.

48 In order to normalize the index results (i.e., bound the results between +1.00 and -1.00), the index is calculated as (Price – Cost)/Price when price is greater than cost, and (Price – Cost)/Cost when price is less than cost.

Real-Time Markup

Table 3-26 shows the average markup index of marginal units in the Real-Time Energy Market, by offer price category using unadjusted cost offers. Table 3-27 shows the average markup index of marginal units in the Real-Time Energy Market, by offer price category using adjusted cost offers. The markup is negative if the cost-based offer of the marginal unit exceeds its price-based offer at its operating point. In 2015, 85.9 percent of marginal units had average dollar markups less than zero, when using unadjusted offers. In 2015, 47.1 percent of marginal units had average dollar markups less than zero, when using adjusted offers. The data show that some marginal units did have substantial markups. Using unadjusted cost offers, 0.17 percent of offers had offer prices greater than $400 per MWh with average dollar markup of $56.87 per MWh. Using the unadjusted cost offers, the highest markup in 2015 was $792.21 while the highest markup in 2014 was $922.26.

Table 3-26 Average, real-time marginal unit markup index (By offer price category unadjusted): 2014 and 2015

	2014			2015		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $25	(0.1 0)	($2.43)	16.9%	(0.04)	($2.45)	47.1%
$25 to $50	(0.02)	($1.04)	58.8%	(0.02)	($1.32)	38.9%
$50 to $75	0.06	$2.52	6.7%	0.08	$4.39	2.8%
$75 to $100	0.12	$9.46	1.9%	0.13	$10.46	1.1%
$100 to $125	0.04	$4.29	3.4%	0.11	$11.48	1.2%
$125 to $150	0.11	$13.69	1.0%	0.03	$3.33	3.1%
>= $150	0.05	$13.25	11.3%	0.05	$12.54	5.8%

Table 3-27 Average, real-time marginal unit markup index (By offer price category adjusted): 2014 and 2015

	2014			2015		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $25	(0.06)	($1.46)	16.9%	(0.00)	($1.45)	47.1%
$25 to $50	0.03	$0.40	58.8%	0.03	$0.31	38.9%
$50 to $75	0.07	$3.20	6.7%	0.10	$5.44	2.8%
$75 to $100	0.13	$10.08	1.9%	0.14	$10.93	1.1%
$100 to $125	0.04	$4.43	3.4%	0.11	$11.75	1.2%
$125 to $150	0.11	$13.84	1.0%	0.03	$3.40	3.1%
>= $150	0.05	$13.35	11.3%	0.05	$12.75	5.8%

Day-Ahead Markup

Table 3-28 shows the average markup index of marginal units in the Day-Ahead Energy Market, by offer price category using unadjusted offers. In 2015, 3.2 percent of marginal units had average dollar markups less than zero and an average markup index less than or equal to 0.00. The data show that some marginal units in 2014 did have substantial markups. The average markup index decreased significantly, for example, from 0.16 in 2014, to 0.02 in 2015 in the offer price category from $100 to $125.

Table 3-28 Average day-ahead marginal unit markup index (By offer price category, unadjusted): 2014 and 2015

	2014			2015		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $25	(0.08)	($2.31)	16.5%	0.08	$0.29	43.9%
$25 to $50	(0.02)	($0.90)	70.5%	0.06	$1.42	45.3%
$50 to $75	0.05	$2.17	7.5%	0.15	$8.77	2.4%
$75 to $100	0.09	$6.63	1.1%	0.05	$3.69	1.0%
$100 to $125	0.16	$17.04	0.8%	0.02	($0.25)	0.8%
$125 to $150	0.02	($2.02)	0.7%	(0.00)	($0.68)	3.2%
>= $150	0.04	$8.53	2.7%	0.02	$3.58	3.1%

Table 3-29 shows the average markup index of marginal units in the Day-Ahead Energy Market, by offer price category using adjusted offers. In 2015, 2.1 percent of marginal units had average dollar markups less than zero and an average markup index less than or equal to 0.00. The average markup index decreased significantly, for example, from 0.15 in 2014, to 0.00 in 2015 in the offer price category from $100 to $125.

Table 3-29 Average day-ahead marginal unit markup index (By offer price category, adjusted): 2014 and 2015

	2014			2015		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $25	(0.02)	($0.76)	16.5%	0.10	$0.86	43.9%
$25 to $50	0.04	$1.17	70.5%	0.09	$2.55	45.3%
$50 to $75	0.07	$3.78	7.5%	0.17	$9.79	2.4%
$75 to $100	0.09	$7.15	1.1%	0.05	$3.93	1.0%
$100 to $125	0.16	$17.26	0.8%	0.02	$0.22	0.8%
$125 to $150	0.02	($1.86)	0.7%	0.00	($0.60)	3.2%
>= $150	0.08	$17.63	2.7%	0.02	$3.63	3.1%

Frequently Mitigated Units and Associated Units

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.[49] 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.[50] FMU and AU adders no longer serve the purpose for which they were created and interfere with the efficient operation of PJM markets.

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.[51]

49 110 FERC ¶ 61,053 (2005).

50 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 >

51 PJM. OA, Schedule 1 § 6.4.2.

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.[52] 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.

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.[53] 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 in December 2014 (See Table 3-31).

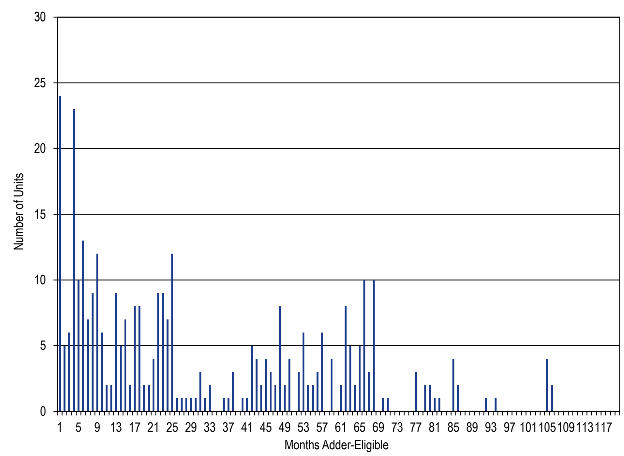
Table 3-30 shows the number of units that were eligible for an FMU or AU adder (Tier 1, Tier 2 or Tier 3) by the number of months they were eligible in 2014 and 2015.[54] In 2015, no units qualified as an FMU or AU.

Table 3-30 Frequently mitigated units and associated units by total months eligible: 2014 and 2015

	FMU & AU Count	
Months Adder-Eligible	2014	2015
1	23	0
2	6	0
3	0	0
4	4	0
5	4	0
6	15	0
7	2	0
8	5	0
9	8	0
10	5	0
11	39	0
12	0	0
Total	111	0

Figure 3-24 shows the number of months FMUs and AUs were eligible for any adder (Tier 1, Tier 2 or Tier 3) since the inception of FMUs effective February 1, 2006. From February 1, 2006, through December 31, 2015, there were 351 unique units that have qualified for an FMU adder in at least one month. Of these 351 units, no unit qualified for an adder in all months. Two units qualified in 106 of the 120 possible months, and 70 of the 351 units (19.9 percent) qualified for an adder in more than half of the possible months.

Figure 3-24 Frequently mitigated units and associated units total months eligible: February, 2006 through December, 2015



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

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

54 The data on FMUs and AUs reported in the *2015 Quarterly State of the Market Report for PJM: January through March*, reflected an incorrect calculation by the MMU. In fact, there should have been zero FMUs and AUs since the implementation of the new FMU rules effective for December 2014.

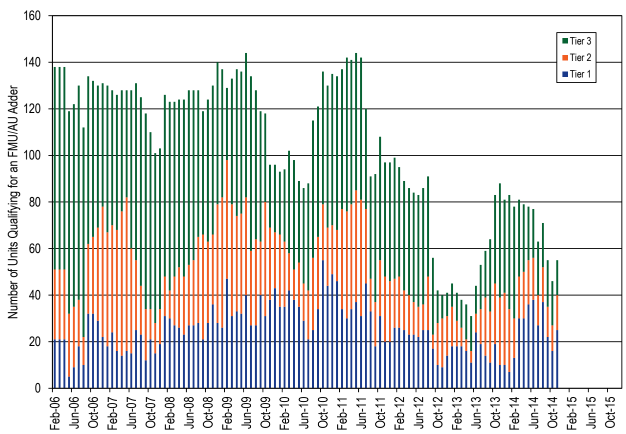
Table 3-31 shows, by month, the number of FMUs and AUs in 2014 and 2015. For example, in November 2014, there were 25 FMUs and AUs in Tier 1, 15 FMUs and AUs in Tier 2, and 15 FMUs and AUs in Tier 3. In 2015, no units qualified as an FMU or AU.[55]

Table 3-31 Number of frequently mitigated units and associated units (By month): 2014 and 2015

	2014				2015			
	Tier 1	Tier 2	Tier 3	Total Eligible for Any Adder	Tier 1	Tier 2	Tier 3	Total Eligible for Any Adder
January	7	27	49	83	0	0	0	0
February	13	17	48	78	0	0	0	0
March	30	18	33	81	0	0	0	0
April	30	20	29	79	0	0	0	0
May	36	19	23	78	0	0	0	0
June	38	18	21	77	0	0	0	0
July	27	13	23	63	0	0	0	0
August	37	15	19	71	0	0	0	0
September	22	13	20	55	0	0	0	0
October	16	11	19	46	0	0	0	0
November	25	15	15	55	0	0	0	0
December	0	0	0	0	0	0	0	0

Figure 3-25 shows the total number of FMUs and AUs that qualified for an adder since the inception of the business rule in February 2006.

Figure 3-25 Frequently mitigated units and associated units (By month): February, 2006 through December, 2015



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.[56] 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 3-26 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 2015.

55 An error in the Market Monitoring Unit's (MMU) monthly calculation used to determine unit eligibility for the Frequently Mitigated Unit (FMU) adder under the new FMU rules resulted in a number of generators permitted to use an adder when no units should have been permitted to use an adder. This occurred for the period from December 1, 2014, the first day that the new FMU rules had an effect, to April 22, 2015. There was no impact on the day-ahead market outcomes resulting from the incorrect FMU status. A total of four five-minute intervals in the real-time market were affected. There was no impact on the monthly PJM system-wide load-weighted real-time LMP.

56 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>.

Figure 3-26 PJM day-ahead aggregate supply curves: 2015 example day

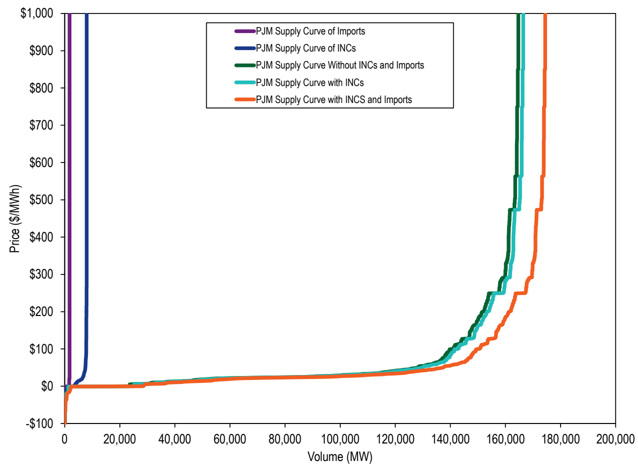


Table 3-32 shows the hourly average number of cleared and submitted increment and decrements by month for 2014 and 2015. The hourly average submitted and cleared increment MW increased by 35.9 and 33.8 percent, from 5,279 MW and 3,494 MW in 2014 to 7,175 MW and 4,675 MW in 2015. The hourly average submitted and cleared decrement MW decreased by 25.8 and 38.6 percent, from 9,278 MW and 6,596 MW in 2014 to 6,879 MW and 4,051 MW in 2015.

Table 3-32 Hourly average number of cleared and submitted INCs, DECs by month: 2014 and 2015

		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
2014	Jan	3,086	4,165	69	214	5,844	8,372	81	322
2014	Feb	3,085	3,985	64	171	5,981	9,108	82	286
2014	Mar	2,961	3,889	66	179	6,744	9,452	97	291
2014	Apr	2,837	3,722	69	181	5,693	7,720	86	279
2014	May	3,981	6,008	73	248	6,042	10,238	104	418
2014	Jun	3,486	5,101	62	219	6,716	8,806	105	324
2014	Jul	3,892	6,350	66	305	7,331	9,514	146	402
2014	Aug	3,465	4,981	66	293	6,540	7,967	155	331
2014	Sep	3,416	5,020	69	356	6,996	8,839	198	417
2014	Oct	3,477	5,826	91	470	6,806	9,991	136	510
2014	Nov	4,210	7,151	134	553	7,193	11,028	166	637
2014	Dec	3,992	7,021	102	525	7,210	10,260	139	490
2014	Annual	3,494	5,279	78	310	6,596	9,278	125	393
2015	Jan	4,350	6,447	78	398	5,153	7,320	76	295
2015	Feb	4,754	7,109	116	578	4,511	7,445	72	409
2015	Mar	4,973	8,689	142	760	4,305	8,894	101	648
2015	Apr	4,511	6,351	187	558	3,453	6,990	84	451
2015	May	5,089	7,459	181	656	4,171	6,823	94	404
2015	Jun	4,592	7,043	143	697	4,196	6,696	89	410
2015	Jul	4,101	6,534	128	745	3,335	5,830	86	448
2015	Aug	4,457	6,956	135	749	3,433	5,506	74	398
2015	Sep	4,527	6,772	148	733	4,391	7,030	112	437
2015	Oct	4,631	7,112	199	846	3,990	6,757	112	462
2015	Nov	5,022	7,822	223	1,008	3,671	6,435	109	482
2015	Dec	5,102	7,775	189	1,010	4,028	6,869	129	486
2015	Annual	4,675	7,175	156	729	4,051	6,879	95	444

The reduction in up to congestion transactions (UTC) continued, following a FERC order setting September 8, 2014, as the effective date for any uplift charges subsequently assigned to UTCs.[57] Table 3-33 shows the average hourly number of up to congestion transactions and the average hourly MW for 2014 and 2015. In 2015, the average hourly up to congestion submitted MW decreased 49.9 percent and cleared MW decreased 61.1 percent, compared to 2014, as a result of the decreases after September 8, 2014. Section 206(b) of the Federal Power Act states that "...the Commission may order refunds of any amounts paid, for the period subsequent to the refund effective date through a date fifteen months after such refund effective date..."[58] An increase in up to congestion volume was observed in December 2015, coincident with the expiration of the fifteen month resettlement period in this proceeding. In December 2015, the hourly average up to congestion submitted MW increased 14.1 percent and cleared MW increased 29.9 percent, compared to November 2015.

Table 3-33 Hourly average of cleared and submitted up to congestion bids by month: 2014 and 2015

		Up to Congestion			
Year		Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume
2014	Jan	55,969	199,708	2,436	7,056
2014	Feb	64,123	229,256	3,262	9,020
2014	Mar	66,003	243,469	3,527	10,920
2014	Apr	73,453	224,924	3,216	8,390
2014	May	73,853	251,463	3,057	8,860
2014	Jun	69,050	235,590	2,781	8,221
2014	Jul	66,800	212,485	2,855	7,856
2014	Aug	66,272	214,713	3,003	7,933
2014	Sep	25,370	86,237	1,210	2,979
2014	Oct	9,298	30,502	512	1,289
2014	Nov	11,890	36,600	661	1,633
2014	Dec	12,952	37,177	770	1,770
2014	Annual	49,511	166,537	2,269	6,315
2015	Jan	15,903	46,626	806	2,132
2015	Feb	17,255	57,318	892	2,695
2015	Mar	18,382	72,906	978	2,909
2015	Apr	16,300	73,446	811	2,734
2015	May	18,929	81,358	941	3,219
2015	Jun	17,714	81,452	896	3,220
2015	Jul	18,883	88,543	952	3,502
2015	Aug	18,490	102,084	1,126	4,291
2015	Sep	20,779	108,730	1,451	4,909
2015	Oct	20,183	100,673	1,493	4,736
2015	Nov	20,880	86,857	1,468	4,067
2015	Dec	27,124	99,083	1,933	4,841
2015	Annual	19,255	83,422	1,147	3,611

Table 3-34 shows the average hourly number of import and export transactions and the average hourly MW for 2014 and 2015. In 2015, the average hourly submitted MW increased by 3.2 percent, cleared import transaction MW decreased by 0.2 percent, and the average hourly submitted and cleared export transaction MW decreased 17.3 and 16.3 percent, compared to 2014.

57 148 FERC ¶ 61,144 (2014).
58 16 U.S.C. § 824e.

Table 3-34 Hourly average number of cleared and submitted import and export transactions by month: 2014 and 2015

		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
2014	Jan	2,347	2,515	14	15	3,495	3,887	21	24
2014	Feb	2,419	2,616	13	15	4,299	4,584	24	26
2014	Mar	2,450	2,496	15	15	5,069	5,293	27	29
2014	Apr	2,017	2,045	13	13	4,164	4,171	22	22
2014	May	2,162	2,168	13	13	2,664	2,674	18	18
2014	Jun	2,527	2,536	13	14	3,643	3,645	22	22
2014	Jul	2,236	2,279	12	12	3,786	3,787	21	21
2014	Aug	2,224	2,236	11	12	3,138	3,140	18	18
2014	Sep	2,114	2,123	11	11	3,744	3,755	23	23
2014	Oct	1,714	1,721	11	11	3,506	3,525	20	21
2014	Nov	2,087	2,097	13	13	3,491	3,528	21	21
2014	Dec	2,373	2,498	12	13	3,939	3,959	21	22
2014	Annual	2,221	2,276	12	13	3,740	3,823	22	22
2015	Jan	2,579	2,716	15	17	4,473	4,559	26	26
2015	Feb	2,588	2,726	17	19	4,383	4,469	23	25
2015	Mar	2,484	2,668	16	18	3,268	3,302	16	17
2015	Apr	2,531	2,638	18	21	2,624	2,626	13	13
2015	May	2,339	2,482	18	20	2,612	2,623	17	17
2015	Jun	2,269	2,349	14	16	2,895	2,906	14	14
2015	Jul	2,319	2,445	16	18	2,961	2,983	14	14
2015	Aug	2,410	2,549	14	16	3,209	3,239	15	15
2015	Sep	1,854	2,015	11	14	3,873	3,913	18	18
2015	Oct	1,419	1,485	8	9	2,190	2,197	11	11
2015	Nov	1,840	1,988	15	17	2,715	2,734	15	15
2015	Dec	1,998	2,137	18	20	2,475	2,483	13	13
2015	Annual	2,217	2,348	15	17	3,131	3,160	16	17

Table 3-35 shows the frequency with which generation offers, import or export transactions, up to congestion transactions, decrement bids, increment offers and price-sensitive demand are marginal for 2014 and 2015.

Table 3-35 Type of day-ahead marginal units: 2014 and 2015

	2014						2015					
	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	Price Sensitive Demand
Jan	2.7%	0.1%	94.5%	1.4%	1.2%	0.0%	14.2%	0.5%	71.9%	6.9%	6.3%	0.1%
Feb	2.0%	0.3%	94.8%	1.9%	1.1%	0.0%	13.1%	0.4%	73.1%	7.6%	5.6%	0.1%
Mar	2.5%	0.2%	94.7%	1.5%	1.0%	0.0%	10.0%	0.7%	73.3%	10.6%	5.3%	0.0%
Apr	2.3%	0.0%	95.1%	1.4%	1.2%	0.0%	10.4%	0.3%	73.2%	10.8%	5.3%	0.0%
May	1.6%	0.0%	92.0%	4.0%	2.4%	0.0%	10.2%	0.1%	75.2%	9.2%	5.3%	0.0%
Jun	2.0%	0.0%	94.6%	2.0%	1.4%	0.0%	8.0%	0.1%	78.2%	9.5%	4.1%	0.0%
Jul	2.1%	0.0%	93.9%	2.1%	1.9%	0.0%	7.2%	0.1%	81.1%	7.8%	3.8%	0.0%
Aug	2.2%	0.0%	94.8%	1.5%	1.6%	0.0%	6.0%	0.1%	83.4%	7.1%	3.3%	0.0%
Sep	6.9%	0.1%	84.1%	5.5%	3.5%	0.0%	7.2%	0.2%	80.0%	7.5%	5.1%	0.0%
Oct	12.2%	0.1%	64.0%	14.5%	9.2%	0.0%	9.8%	0.1%	72.4%	11.2%	6.6%	0.0%
Nov	10.1%	0.2%	64.9%	14.6%	10.1%	0.0%	11.8%	0.1%	72.0%	10.7%	5.3%	0.0%
Dec	12.6%	0.2%	67.2%	12.4%	7.6%	0.0%	7.3%	0.1%	79.8%	8.0%	4.8%	0.0%
Total	3.3%	0.1%	91.0%	3.3%	2.3%	0.0%	9.6%	0.3%	76.1%	8.9%	5.1%	0.0%

Figure 3-27 shows the monthly volume of bid and cleared INC, DEC and up to congestion bids by month for the period from January 2005 through September 2015.

Figure 3-27 Monthly bid and cleared INCs, DECs, and UTCs (MW): January 2005 through December 2015

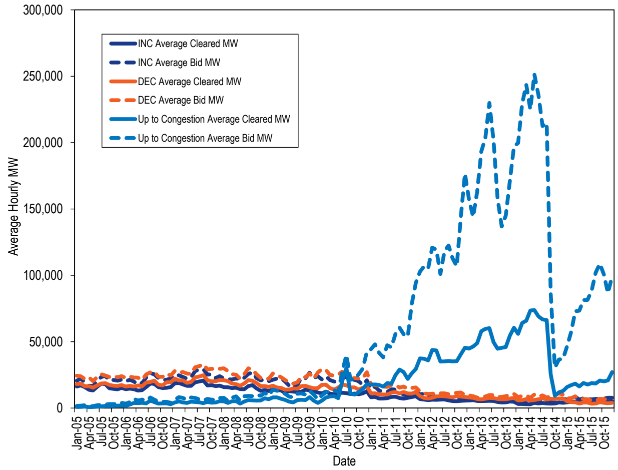
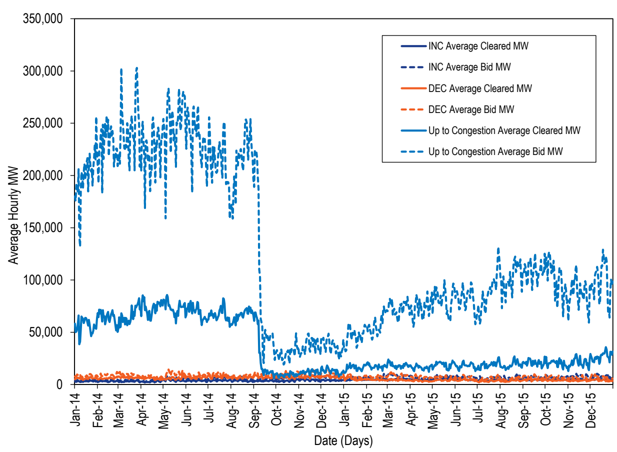


Figure 3-28 shows the daily volume of bid and cleared INC, DEC and up to congestion bids for the period from January 2014 through December 2015.

Figure 3-28 Daily bid and cleared INCs, DECs, and UTCs (MW): January 2014 through December 2015



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 3-36 shows, for 2014 and 2015, the total increment offers and decrement bids by whether the parent organization is financial or physical.

Table 3-36 PJM INC and DEC bids by type of parent organization (MW): 2014 and 2015

	2014		2015	
Category	Total Virtual Bids MW	Percent	Total Virtual Bids MW	Percent
Financial	45,631,883	35.8%	54,941,962	44.6%
Physical	81,887,800	64.2%	68,165,222	55.4%
Total	127,519,683	100.0%	123,107,185	100.0%

Table 3-37 shows, for 2014 and 2015, the total up to congestion transactions by whether the parent organization is financial or physical.

Table 3-37 PJM up to congestion transactions by type of parent organization (MW): 2014 and 2015

	2014		2015	
Category	Total Up to Congestion MW	Percent	Total Up to Congestion MW	Percent
Financial	407,879,549	94.0%	134,555,951	79.8%
Physical	25,839,452	6.0%	34,117,122	20.2%
Total	433,719,001	100.0%	168,673,073	100.0%

Table 3-38 shows for 2014 and 2015, the total import and export transactions by whether the parent organization is financial or physical.

Table 3-38 PJM import and export transactions by type of parent organization (MW): 2014 and 2015

	2014		2015	
Category	Total Import and Export MW	Percent	Total Import and Export MW	Percent
Financial	18,874,396	35.3%	19,015,698	38.6%
Physical	34,598,073	64.7%	30,214,300	61.4%
Total	53,472,469	100.0%	49,229,998	100.0%

Table 3-39 shows increment offers and decrement bids bid by top ten locations for 2014 and 2015.

Table 3-39 PJM virtual offers and bids by top ten locations (MW): 2014 and 2015

2014					2015				
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	14,144,703	15,893,094	30,037,797	WESTERN HUB	HUB	19,527,215	21,691,683	41,218,898
MISO	INTERFACE	398,020	7,059,365	7,457,385	SOUTHIMP	INTERFACE	7,136,144	0	7,136,144
PPL	ZONE	267,547	6,406,394	6,673,941	N ILLINOIS HUB	HUB	905,858	2,733,941	3,639,799
SOUTHIMP	INTERFACE	5,941,022	0	5,941,022	IMO	INTERFACE	3,530,900	70,753	3,601,653
PECO	ZONE	353,741	5,389,431	5,743,172	NYIS	INTERFACE	1,895,475	400,046	2,295,521
AEP-DAYTON HUB	HUB	2,299,031	2,368,105	4,667,135	BGE	ZONE	223,721	1,750,290	1,974,011
IMO	INTERFACE	4,236,242	174,918	4,411,159	MISO	INTERFACE	414,835	1,216,550	1,631,385
N ILLINOIS HUB	HUB	1,044,461	2,696,413	3,740,873	BAGLEY 34 KV 230-1LD	LOAD	403,792	912,882	1,316,673
BGE	ZONE	25,650	2,999,433	3,025,084	AEP-DAYTON HUB	HUB	651,596	649,136	1,300,732
NYIS	INTERFACE	1,081,753	488,366	1,570,119	DOMINION HUB	HUB	365,184	811,772	1,176,956
Top ten total		29,792,169	43,475,518	73,267,687			35,054,718	30,237,052	65,291,770
PJM total		46,227,055	81,206,816	127,433,871			62,848,910	60,258,275	123,107,185
Top ten total as percent of PJM total		64.4%	53.5%	57.5%			55.8%	50.2%	53.0%

Table 3-40 shows up to congestion transactions by import bids for the top ten locations for 2014 and 2015.[59]

Table 3-40 PJM cleared up to congestion import bids by top ten source and sink pairs (MW): 2014 and 2015

2014				
Imports				
Source	Source Type	Sink	Sink Type	MW
HUDSONTP	INTERFACE	LEONIA 230 T-2	AGGREGATE	979,669
SOUTHEAST	INTERFACE	EDANVILL T1	AGGREGATE	759,991
MISO	INTERFACE	COOK	EHVAGG	666,261
OVEC	INTERFACE	BIG SANDY CT1	AGGREGATE	603,745
NORTHWEST	INTERFACE	N ILLINOIS HUB	HUB	571,373
MISO	INTERFACE	AEP-DAYTON HUB	HUB	462,719
NEPTUNE	INTERFACE	SOUTHRIV 230	AGGREGATE	436,574
SOUTHEAST	INTERFACE	CLOVER	EHVAGG	428,397
OVEC	INTERFACE	AEP-DAYTON HUB	HUB	402,375
HUDSONTP	INTERFACE	LEONIA 230 T-1	AGGREGATE	383,260
Top ten total				5,694,366
PJM total				29,282,620
Top ten total as percent of PJM total				19.4%
2015				
Imports				
Source	Source Type	Sink	Sink Type	MW
SOUTHIMP	INTERFACE	NAGELAEP	EHVAGG	1,480,928
NORTHWEST	INTERFACE	N ILLINOIS HUB	HUB	445,796
SOUTHEAST	INTERFACE	CLOVER	EHVAGG	413,115
NORTHWEST	INTERFACE	COMED	ZONE	412,351
SOUTHEAST	INTERFACE	HALIFXDP TX1	AGGREGATE	364,808
OVEC	INTERFACE	AEP-DAYTON HUB	HUB	356,720
SOUTHIMP	INTERFACE	WOLF HILLS 1-5	AGGREGATE	342,579
SOUTHEAST	INTERFACE	DOM	ZONE	277,721
OVEC	INTERFACE	MALISZEWSKI	EHVAGG	258,387
MISO	INTERFACE	21 KINCA ATR24304	AGGREGATE	244,650
Top ten total				4,597,055
PJM total				19,561,806
Top ten total as percent of PJM total				23.5%

Table 3-41 shows up to congestion transactions by export bids for the top ten locations for 2014 and 2015.

Table 3-41 PJM cleared up to congestion export bids by top ten source and sink pairs (MW): 2014 and 2015

2014				
Exports				
Source	Source Type	Sink	Sink Type	MW
JEFFERSON	EHVAGG	OVEC	INTERFACE	2,073,052
TANNERS CRK 4	AGGREGATE	SOUTHWEST	INTERFACE	1,782,780
TANNERS CRK 4	AGGREGATE	OVEC	INTERFACE	809,364
21 KINCA ATR24304	AGGREGATE	SOUTHWEST	INTERFACE	693,816
ROCKPORT	EHVAGG	SOUTHWEST	INTERFACE	607,054
JEFFERSON	EHVAGG	SOUTHWEST	INTERFACE	606,723
ROCKPORT	EHVAGG	OVEC	INTERFACE	564,629
EAST BEND 2	AGGREGATE	SOUTHWEST	INTERFACE	427,156
UNIV PARK 1-6	AGGREGATE	NIPSCO	INTERFACE	426,011
BECKJORD 6	AGGREGATE	OVEC	INTERFACE	418,718
Top ten total				8,409,302
PJM total				30,285,649
Top ten total as percent of PJM total				27.8%
2015				
Exports				
Source	Source Type	Sink	Sink Type	MW
SULLIVAN-AEP	EHVAGG	OVEC	INTERFACE	460,314
FOWLER 34.5 KV FWLR1AWF	AGGREGATE	SOUTHWEST	INTERFACE	378,483
21 KINCA ATR24304	AGGREGATE	SOUTHWEST	INTERFACE	367,085
FOWLER RIDGE II WF	AGGREGATE	SOUTHWEST	INTERFACE	360,994
ROCKPORT	EHVAGG	SOUTHWEST	INTERFACE	303,419
COMED	ZONE	NIPSCO	INTERFACE	274,034
21 KINCA ATR24304	AGGREGATE	NIPSCO	INTERFACE	270,867
SULLIVAN-AEP	EHVAGG	SOUTHWEST	INTERFACE	222,668
21 KINCA ATR24404	AGGREGATE	SOUTHWEST	INTERFACE	217,732
SULLIVAN-AEP	EHVAGG	MISO	INTERFACE	167,996
Top ten total				3,023,589
PJM total				9,849,007
Top ten total as percent of PJM total				30.7%

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 shows up to congestion transactions by wheel bids for the top ten locations for 2014 and 2015.

Table 3-42 PJM cleared up to congestion wheel bids by top ten source and sink pairs (MW): 2014 and 2015

2014				
Wheels				
Source	Source Type	Sink	Sink Type	MW
NORTHWEST	INTERFACE	MISO	INTERFACE	775,527
OVEC	INTERFACE	SOUTHEXP	INTERFACE	344,298
MISO	INTERFACE	NORTHWEST	INTERFACE	334,888
SOUTHWEST	INTERFACE	SOUTHEXP	INTERFACE	255,763
MISO	INTERFACE	NIPSCO	INTERFACE	128,693
OVEC	INTERFACE	SOUTHWEST	INTERFACE	120,854
MISO	INTERFACE	SOUTHEXP	INTERFACE	97,877
NYIS	INTERFACE	IMO	INTERFACE	97,249
IMO	INTERFACE	NYIS	INTERFACE	91,942
NORTHWEST	INTERFACE	NIPSCO	INTERFACE	89,794
Top ten total				2,336,885
PJM total				2,984,112
Top ten total as percent of PJM total				78.3%
2015				
Wheels				
Source	Source Type	Sink	Sink Type	MW
MISO	INTERFACE	NORTHWEST	INTERFACE	361,210
NORTHWEST	INTERFACE	MISO	INTERFACE	232,735
MISO	INTERFACE	NIPSCO	INTERFACE	221,536
NYIS	INTERFACE	IMO	INTERFACE	129,966
IMO	INTERFACE	NYIS	INTERFACE	113,455
SOUTHWEST	INTERFACE	SOUTHEXP	INTERFACE	47,741
SOUTHWEST	INTERFACE	IMO	INTERFACE	33,166
NIPSCO	INTERFACE	IMO	INTERFACE	29,379
SOUTHEAST	INTERFACE	SOUTHEXP	INTERFACE	21,292
MISO	INTERFACE	SOUTHWEST	INTERFACE	20,984
Top ten total				1,211,465
PJM total				1,453,602
Top ten total as percent of PJM total				83.3%

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 ten internal up to congestion transaction locations were 8.2 percent of the PJM total internal up to congestion transactions in 2015.

Table 3-43 shows up to congestion transactions by internal bids for the top ten locations for 2014 and 2015.

Table 3-43 PJM cleared up to congestion internal bids by top ten source and sink pairs (MW): 2014 and 2015

2014				
Internal				
Source	Source Type	Sink	Sink Type	MW
MOUNTAINEER	EHVAGG	GAVIN	EHVAGG	6,627,189
DAY	ZONE	BUCKEYE - DPL	AGGREGATE	5,207,776
MOUNTAINEER	EHVAGG	FLATLICK	EHVAGG	4,297,331
ATSI GEN HUB	HUB	ATSI	ZONE	4,114,584
VERNON BK 4	AGGREGATE	AEC - JC	AGGREGATE	3,733,527
FE GEN	AGGREGATE	ATSI	ZONE	3,357,260
JEFFERSON	EHVAGG	COOK	EHVAGG	2,548,989
DUMONT	EHVAGG	COOK	EHVAGG	2,466,575
WESTERN HUB	HUB	AEP-DAYTON HUB	HUB	2,147,264
TANNERS CRK 4	AGGREGATE	STUART DIESEL	AGGREGATE	1,813,835
Top ten total				36,314,330
PJM total				371,166,620
Top ten total as percent of PJM total				9.8%
2015				
Internal				
Source	Source Type	Sink	Sink Type	MW
BERGEN 2CC	AGGREGATE	LEONIA 230 T-1	AGGREGATE	2,362,692
ROCKPORT	EHVAGG	JEFFERSON	EHVAGG	1,763,337
BYRON 1	AGGREGATE	ROCKFORD	AGGREGATE	1,465,725
BERGEN 2CC	AGGREGATE	LEONIA 230 T-2	AGGREGATE	1,017,317
JEFFERSON	EHVAGG	COOK	EHVAGG	958,975
MARYSVILLE	EHVAGG	MALISZEWSKI	EHVAGG	892,606
BLACKOAK	EHVAGG	BEDINGTON	EHVAGG	718,298
PSEG	ZONE	WESTERN HUB	HUB	711,099
WHIPPANY BK 7	AGGREGATE	TRAYNOR	AGGREGATE	686,989
21 KINCA ATR24304	AGGREGATE	DUMONT - OLIVE	AGGREGATE	673,830
Top ten total				11,250,868
PJM total				137,808,658
Top ten total as percent of PJM total				8.2%

Table 3-44 shows the number of source-sink pairs that were offered and cleared monthly in January 2013 through December 2015. The annual row in Table 3-44 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. There was a decrease in UTCs in September as a result of a FERC order setting September 8, 2014, as the effective date for any uplift charges assigned to UTCs.[60]

60 See 148 FERC ¶ 61,144 (2014)..

Table 3-44 Number of PJM offered and cleared source and sink pairs: January 2013 through December 2015

		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

Table 3-45 and Figure 3-29 show total cleared up to congestion transactions by type for 2014 and 2015. Internal up to congestion transactions in 2015 were 81.7 percent of all up to congestion transactions compared to 85.6 percent in 2014.

Table 3-45 PJM cleared up to congestion transactions by type (MW): 2014 and 2015

	2014				
	Cleared Up to Congestion Bids				
	Import	Export	Wheel	Internal	Total
Top ten total (MW)	5,694,366	8,409,302	2,336,885	36,314,330	52,754,883
PJM total (MW)	29,282,620	30,285,649	2,984,112	371,166,620	433,719,001
Top ten total as percent of PJM total	19.4%	27.8%	78.3%	9.8%	12.2%
PJM total as percent of all up to congestion transactions	6.8%	7.0%	0.7%	85.6%	100.0%
	2015				
	Cleared Up to Congestion Bids				
	Import	Export	Wheel	Internal	Total
Top ten total (MW)	4,597,055	3,023,589	1,211,465	11,250,868	20,082,977
PJM total (MW)	19,561,806	9,849,007	1,453,602	137,808,658	168,673,073
Top ten total as percent of PJM total	23.5%	30.7%	83.3%	8.2%	11.9%
PJM total as percent of all up to congestion transactions	11.6%	5.8%	0.9%	81.7%	100.0%

Figure 3-29 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. There was a decrease in UTCs in September as a result of a FERC order setting September 8, 2014, as the effective date for any uplift charges subsequently assigned to UTCs and an increase in UTCs in December 2015, coincident with the expiration of the fifteen month resettlement period in this proceeding.[61]

Figure 3-29 PJM monthly cleared up to congestion transactions by type (MW): January 2005 through December 2015

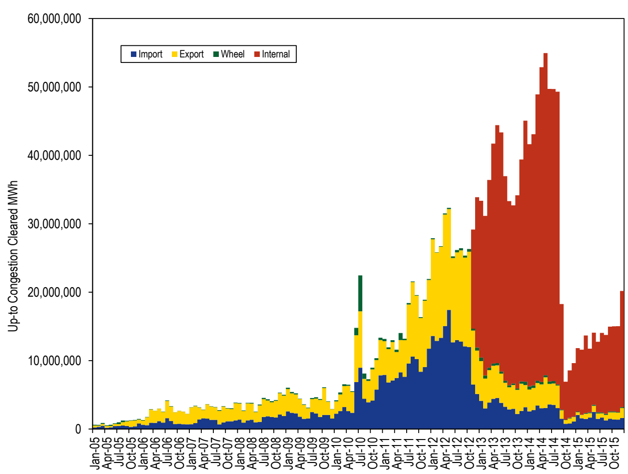
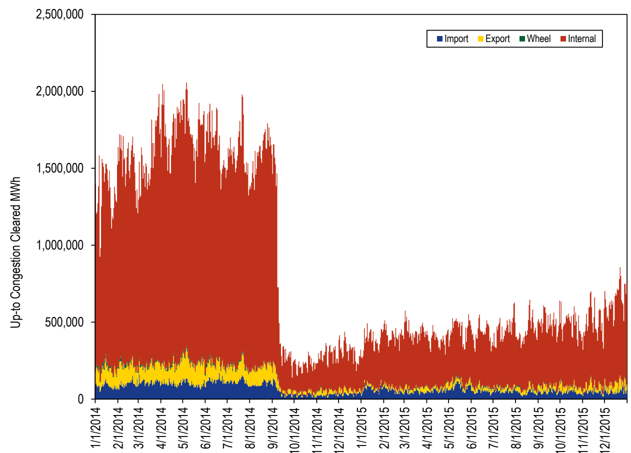


Figure 3-30 shows the daily cleared up to congestion MW by transaction type for the period from January 2014 through December 2015.

Figure 3-30 PJM daily cleared up to congestion transaction by type (MW): January 2014 through December 2015



Generator Offers

Generator offers are categorized as dispatchable (Table 3-46) or self scheduled (Table 3-47).[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 3-46 and Table 3-47 do not include units that did not indicate their offer status and units that were offered as available to run only during emergency events. The MW offered beyond the economic range of a unit are categorized as emergency MW. The emergency MW are included in both tables.

61 See 148 FERC ¶ 61,144 (2014).

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 3-46 shows the proportion of MW offers by dispatchable units, by unit type and by offer price range, for 2015. For example, 73.0 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, 81.2 percent of all CC MW offers were dispatchable, including the 6.2 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, 46.7 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 2015, 51.7 percent were offered as available for economic dispatch.

Table 3-47 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 2015. For example, 15.2 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, 18.8 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 1.7 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 22.5 percent of all offers and self-scheduled and dispatchable units accounted for 19.0 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 2015, 23.8 percent were offered as self scheduled and 20.1 percent were offered as self scheduled and dispatchable.

Table 3-46 Distribution of MW for dispatchable unit offer prices: 2015

	Dispatchable (Range)							
Unit Type	($200) - $0	$0 - $200	$200 - $400	$400 - $600	$600 - $800	$800 - $1,000	Emergency	Total
CC	0.2%	73.0%	1.1%	0.3%	0.4%	0.0%	6.2%	81.2%
CT	0.1%	75.3%	10.2%	1.4%	1.2%	0.1%	10.9%	99.1%
Diesel	5.6%	27.7%	18.7%	8.2%	0.9%	0.3%	13.7%	75.0%
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%	6.7%
Pumped Storage	33.5%	21.7%	0.0%	0.0%	0.0%	0.0%	12.5%	67.7%
Run of River	0.2%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.3%
Solar	6.5%	7.2%	0.0%	0.0%	0.0%	0.0%	2.7%	16.4%
Steam	0.1%	47.2%	1.2%	0.1%	0.1%	0.0%	2.6%	51.3%
Transaction	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Wind	48.7%	11.3%	0.0%	0.0%	0.0%	0.0%	0.6%	60.6%
All Dispatchable Offers	1.6%	46.7%	2.6%	0.4%	0.3%	0.0%	4.4%	56.1%

Table 3-47 Distribution of MW for self scheduled offer prices: 2015

	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	1.4%	0.5%	0.2%	15.2%	0.1%	0.0%	0.1%	0.0%	1.2%	18.8%
CT	0.4%	0.1%	0.0%	0.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.9%
Diesel	23.1%	1.0%	0.4%	0.3%	0.1%	0.0%	0.0%	0.0%	0.1%	25.0%
Fuel Cell	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%
Nuclear	91.9%	1.1%	0.0%	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%	93.3%
Pumped Storage	16.1%	8.4%	3.4%	0.0%	0.0%	0.0%	0.0%	0.0%	4.4%	32.3%
Run of River	60.1%	9.9%	2.7%	19.8%	0.0%	0.0%	0.0%	3.5%	3.7%	99.7%
Solar	61.7%	21.6%	0.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	83.6%
Steam	5.4%	1.5%	0.2%	39.6%	0.2%	0.0%	0.0%	0.0%	1.8%	48.7%
Transaction	74.9%	25.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%
Wind	4.1%	2.9%	25.8%	2.8%	0.0%	0.0%	0.0%	0.0%	4.0%	39.4%
All Self-Scheduled Offers	22.5%	1.3%	0.6%	18.2%	0.1%	0.0%	0.0%	0.1%	1.1%	43.9%

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, which is a measure of participant conduct for individual marginal units, does not measure the impact of participant behavior on market prices. 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 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.

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 price-based on a comparison between the price-based offer and the cost-based offer of each actual marginal unit on the system.[63]

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. Thus 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.

The MMU calculated an explicit measure of the impact of marginal unit markups on LMP. 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.

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 3-48 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 3-48 on the system-wide load-weighted LMP. The negative markup components of LMP reflect the negative markups shown in the Table 3-26.

All generating units, including coal units, are allowed to include a 10 percent adder in their cost offer. The 10 percent adder 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 10 percent adder from their actual offers. The unadjusted

63 This is the same method used to calculate the fuel cost adjusted LMP and the components of LMP.

markup is calculated as the difference between the price offer and the cost offer including the 10 percent adder in the cost offer. The adjusted markup is calculated as the difference between the price offer and the cost offer excluding the 10 percent adder from the cost offer. Even the adjusted markup underestimates the markup because coal units facing increased competitive pressure have excluded both the ten percent adder 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 relevant PJM manual, they are not part of a competitive offer for a coal unit because they are not actually short run marginal costs, and market behavior reflected that fact.[64]

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, markup is the difference between the active offer of the marginal unit and the cost offer. In the second approach, the 10 percent markup is removed from the cost offers of coal units because coal units do not face the same cost uncertainty as gas-fired CTs. The adjusted markup is calculated as the difference between the active offer and the cost offer excluding the 10 percent adder. The unadjusted markup is calculated as the difference between the active offer and the cost offer including the 10 percent adder in the cost offer.

Table 3-48 Markup component of the overall PJM real-time, load-weighted, average LMP by primary fuel type and unit type: 2014 and 2015[65]

		2014		2015	
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	$0.32	$1.75	($1.26)	$0.37
Gas	CC	$0.83	$0.83	$1.29	$1.29
Gas	CT	$0.27	$0.27	($0.13)	($0.13)
Gas	Diesel	$0.09	$0.09	$0.02	$0.02
Gas	Steam	($0.01)	($0.01)	$0.02	$0.02
Municipal Waste	Steam	$0.15	$0.15	($0.01)	($0.01)
Oil	CC	$0.09	$0.09	$0.05	$0.05
Oil	CT	$0.09	$0.09	$0.03	$0.03
Oil	Diesel	$0.00	$0.00	$0.00	$0.00
Oil	Steam	$0.03	$0.03	$0.12	$0.12
Other	Steam	($0.00)	($0.00)	($0.05)	($0.05)
Uranium	Steam	$0.01	$0.01	$0.00	$0.00
Wind	Wind	$0.03	$0.03	$0.03	$0.03
Total		$1.88	$3.32	$0.12	$1.75

Table 3-48 shows the mark-up component of the load-weighted LMP by fuel type and unit type using unadjusted and adjusted offers. The adjusted markup component of LMP decreased from $3.22 in 2014 to $1.75 in 2015. The adjusted markup contribution of coal units in 2015 was $0.37. Although the price of natural gas was substantially lower in 2015 than in 2014, the adjusted mark-up component of all gas-fired units in 2015 was $1.20, an increase of $0.03 from 2014. Coal units accounted for 87.8 percent of the decrease in the markup component of LMP in 2015. The markup component of wind units was $0.03. If a price-based offer is negative, but less negative than a cost-based offer, the markup is positive. In 2015, among the wind units that were marginal, 3.81 percent had positive offer prices.

Markup Component of Real-Time Price

Table 3-49 shows the markup component, calculated using unadjusted offers, of average prices and of average monthly on-peak and off-peak prices. Table 3-50 shows the markup component, calculated using adjusted offers, of average prices and of average monthly on-peak and off-peak prices. In 2015, when using unadjusted cost offers, $0.12 per MWh of the PJM real-time load-weighted average LMP was attributable to markup. Using adjusted cost-offers, $1.75 per MWh of the PJM real-time load-weighted average LMP was attributable to markup. In 2015, the peak markup component was highest in February, $7.46 per MWh using unadjusted cost offers and $9.24 per MWh using adjusted cost offers. This corresponds to 13.78 percent and 17.08 percent of the real time load-weighted average LMP in February.[66]

64 See PJM. "Manual 15: Cost Development Guidelines," Revision 26 (November 5, 2014).

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.

66 In the *2015 Quarterly State of the Market Report for PJM: January through March*; January through June; and January through September, the peak markup component was incorrectly reported as $4.79 per MWh using unadjusted cost offers and $6.64 using adjusted cost offers.

Table 3-49 Monthly markup components of real-time load-weighted LMP (Unadjusted): 2014 and 2015

	2014			2015		
	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component
Jan	$5.44	$3.91	$6.92	($1.42)	($2.62)	($0.15)
Feb	$3.02	$0.88	$5.08	$4.62	$1.72	$7.46
Mar	$7.11	$3.24	$11.17	$1.84	$1.82	$1.86
Apr	($0.43)	($2.16)	$1.07	($0.42)	($0.69)	($0.18)
May	$1.74	($1.27)	$4.62	($1.85)	($3.59)	($0.01)
Jun	$2.43	($0.08)	$4.60	($0.43)	($1.20)	$0.21
Jul	($0.15)	($1.22)	$0.77	($0.46)	($1.29)	$0.21
Aug	($1.08)	($1.91)	($0.29)	($0.90)	($0.96)	($0.83)
Sep	$1.51	($0.13)	$3.01	($0.55)	($0.64)	($0.47)
Oct	$2.04	($0.74)	$4.34	($0.13)	($0.35)	$0.08
Nov	$0.17	($1.12)	$1.70	$0.57	($0.42)	$1.62
Dec	($0.19)	($1.59)	$1.13	$0.38	($0.22)	$0.95
Total	$1.88	($0.06)	$3.71	$0.12	($0.72)	$0.92

Table 3-50 Monthly markup components of real-time load-weighted LMP (Adjusted): 2014 and 2015

	2014			2015		
	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component
Jan	$6.83	$5.48	$8.12	$0.61	($0.61)	$1.90
Feb	$3.94	$1.97	$5.84	$6.44	$3.57	$9.24
Mar	$8.21	$4.59	$12.02	$3.71	$3.69	$3.74
Apr	$0.86	($0.45)	$2.00	$1.22	$0.72	$1.65
May	$2.87	$0.09	$5.54	($0.45)	($2.41)	$1.64
Jun	$3.69	$1.46	$5.62	$1.18	$0.06	$2.10
Jul	$1.48	$0.35	$2.44	$1.17	$0.16	$1.97
Aug	$0.50	($0.29)	$1.25	$0.65	$0.43	$0.86
Sep	$3.18	$1.65	$4.59	$0.86	$0.71	$1.00
Oct	$3.71	$1.06	$5.90	$1.43	$0.91	$1.91
Nov	$1.93	$0.80	$3.25	$2.06	$0.80	$3.39
Dec	$1.65	$0.27	$2.97	$1.79	$0.84	$2.68
Total	$3.32	$1.54	$5.00	$1.75	$0.75	$2.70

Hourly Markup Component of Real-Time Prices

Figure 3-31 shows the markup contribution to the hourly load-weighted LMP using unadjusted cost offers for 2015 and 2014. Figure 3-32 shows the markup contribution to the hourly load-weighted LMP using adjusted cost offers for 2015 and 2014. In 2014, high markups were seen during the polar vortex events in January and early March. In contrast, January 2015 had very low markups. Most high markup hours in 2015 were observed in February and March.

Figure 3-31 Markup contribution to real-time hourly load-weighted LMP (Unadjusted): 2014 and 2015

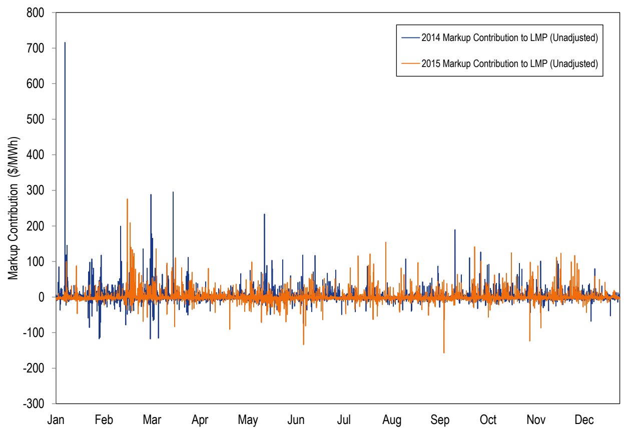
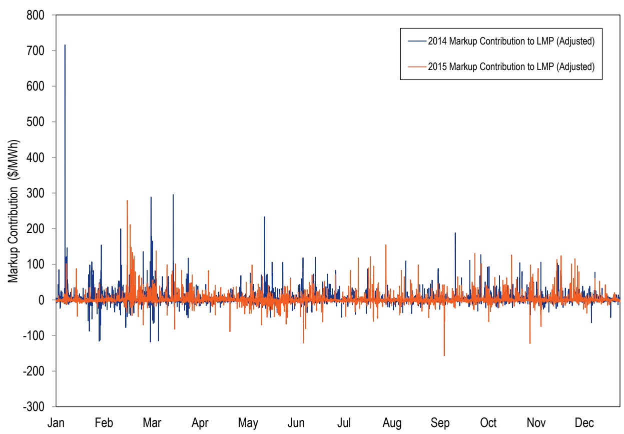


Figure 3-32 Markup contribution to real-time hourly load-weighted LMP (Adjusted): 2014 and 2015



Markup Component of Real-Time Zonal Prices

The unit markup component of average real-time price using unadjusted offers is shown for each zone for 2014 and 2015 in Table 3-51 and for adjusted offers in Table 3-52. The smallest zonal all hours average markup component using unadjusted offers for 2015 was in the DPL Zone, -$0.67 per MWh, while the highest was in the BGE Control Zone, $1.64 per MWh. The smallest zonal on peak average markup was in the AECO Control Zone, -$1.32 per MWh, while the highest was in the BGE Control Zone, $1.00 per MWh.

Table 3-51 Average real-time zonal markup component (Unadjusted): 2014 and 2015

	2014			2015		
	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component
AECO	$1.77	($0.26)	$3.71	($0.62)	($1.32)	$0.05
AEP	$1.59	($0.30)	$3.42	$0.04	($0.97)	$1.00
APS	$1.72	($0.05)	$3.43	$0.56	($0.31)	$1.41
ATSI	$1.25	($0.48)	$2.89	$0.03	($0.89)	$0.89
BGE	$3.14	$0.85	$5.30	$1.64	$1.00	$2.26
ComEd	$0.99	($0.62)	$2.48	($0.22)	($1.04)	$0.53
DAY	$1.27	($0.54)	$2.94	$0.10	($0.97)	$1.09
DEOK	$1.27	($0.57)	$3.01	($0.01)	($1.10)	$1.03
DLCO	$1.53	($0.17)	$3.14	($0.15)	($0.98)	$0.63
DPL	$2.23	$0.25	$4.10	($0.67)	($1.11)	($0.25)
Dominion	$3.15	$0.79	$5.39	$0.79	$0.09	$1.46
EKPC	$1.59	($0.09)	$3.26	$0.05	($1.16)	$1.27
JCPL	$1.50	($0.33)	$3.14	($0.60)	($1.24)	($0.02)
Met-Ed	$1.58	($0.12)	$3.14	($0.52)	($1.22)	$0.13
PECO	$1.83	($0.07)	$3.61	($0.61)	($1.26)	($0.00)
PENELEC	$1.96	($0.11)	$3.89	$0.20	($0.77)	$1.11
PPL	$2.02	($0.03)	$3.94	($0.27)	($1.10)	$0.50
PSEG	$2.33	$0.16	$4.31	($0.19)	($1.10)	$0.63
Pepco	$2.94	$0.73	$4.97	$1.19	$0.36	$1.94
RECO	$2.44	$0.14	$4.39	$0.04	($1.28)	$1.17

Table 3-52 Average real-time zonal markup component (Adjusted): 2014 and 2015

	2014			2015		
	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component
AECO	$3.04	$1.10	$4.88	$0.44	($0.32)	$1.16
AEP	$3.09	$1.37	$4.75	$1.78	$0.59	$2.93
APS	$3.19	$1.56	$4.77	$2.32	$1.28	$3.33
ATSI	$2.74	$1.16	$4.23	$1.76	$0.66	$2.79
BGE	$4.90	$2.78	$6.90	$4.13	$3.16	$5.06
ComEd	$2.41	$1.01	$3.71	$1.34	$0.33	$2.27
DAY	$2.81	$1.16	$4.33	$1.90	$0.60	$3.10
DEOK	$2.75	$1.07	$4.34	$1.75	$0.43	$3.00
DLCO	$3.05	$1.47	$4.53	$1.54	$0.53	$2.49
DPL	$3.46	$1.59	$5.24	$0.44	($0.05)	$0.92
Dominion	$4.67	$2.46	$6.77	$2.77	$1.89	$3.62
EKPC	$3.06	$1.55	$4.57	$1.77	$0.42	$3.14
JCPL	$2.74	$1.03	$4.26	$0.47	($0.24)	$1.10
Met-Ed	$2.77	$1.21	$4.21	$0.53	($0.24)	$1.25
PECO	$3.05	$1.29	$4.69	$0.42	($0.26)	$1.05
PENELEC	$3.33	$1.38	$5.15	$1.67	$0.57	$2.69
PPL	$3.23	$1.31	$5.02	$0.79	($0.09)	$1.61
PSEG	$3.60	$1.52	$5.49	$0.95	($0.03)	$1.85
Pepco	$4.56	$2.52	$6.44	$3.39	$2.29	$4.41
RECO	$3.79	$1.55	$5.70	$1.34	($0.05)	$2.52

Markup by Real Time Price Levels

Table 3-53 shows the average markup component of observed prices, 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 3-53 Average real-time markup component (By price category, unadjusted): 2014 and 2015

	2014		2015	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $25	$0.46	76.0%	($0.14)	89.9%
$25 to $50	($0.15)	12.5%	($0.01)	9.2%
$50 to $75	$0.17	5.0%	$0.11	0.6%
$75 to $100	$0.17	1.9%	$0.09	0.2%
$100 to $125	$0.09	1.0%	$0.02	0.1%
$125 to $150	$0.15	0.8%	$0.04	0.1%
>= $150	$1.01	2.8%	$0.01	0.0%

Table 3-54 Average real-time markup component (By price category, adjusted): 2014 and 2015

	2014		2015	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $25	$1.60	76.0%	$1.32	89.9%
$25 to $50	$0.06	12.5%	$0.15	9.2%
$50 to $75	$0.20	5.0%	$0.12	0.6%
$75 to $100	$0.19	1.9%	$0.10	0.2%
$100 to $125	$0.10	1.0%	$0.02	0.1%
$125 to $150	$0.16	0.8%	$0.04	0.1%
>= $150	$1.05	2.8%	$0.01	0.0%

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 3-55. INC, DEC and up to congestion transactions have zero markups. Up to congestion transactions were 76.1 percent of marginal resources, INCs were 2.3 percent of marginal resources, and DECs were 3.3 percent of marginal resources in 2015. 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.[67] The adjusted markup of coal units is calculated as the difference between the price offer, and the cost offer excluding the 10 percent adder. Table 3-55 shows the markup component of LMP for marginal generating resources. Generating resources were only 9.6 percent of marginal resources in 2015. The markup component of LMP for marginal generating resources decreased in coal-fired steam units and oil-fired CT units. The markup component of LMP for coal units decreased from $0.97 in 2014 to $0.19 in 2015 using adjusted offers. The markup component of LMP for gas-fired CCs increased from -$0.13 in 2014 to $0.75 in 2015 using adjusted offers.

Table 3-55 Markup component of the annual PJM day-ahead, load-weighted, average LMP by primary fuel type and unit type: 2014 and 2015

		2014		2015	
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	($0.29)	$0.97	($0.32)	$0.19
Gas	CC	($0.13)	($0.13)	$0.75	$0.75
Gas	CT	$0.02	$0.02	$0.07	$0.07
Gas	Diesel	$0.00	$0.00	$0.03	$0.03
Gas	Steam	($0.03)	($0.03)	($0.42)	($0.42)
Municipal Waste	Steam	($0.01)	($0.01)	($0.00)	($0.00)
Oil	CC	$0.02	$0.02	$0.03	$0.03
Oil	CT	$0.03	$0.04	$0.02	$0.02
Oil	Diesel	$0.00	$0.00	$0.00	$0.00
Oil	Steam	$0.02	$0.02	$0.07	$0.07
Other	Steam	$0.00	$0.00	($0.00)	($0.00)
Wind	Wind	$0.02	$0.02	$0.05	$0.05
Total		($0.34)	$0.93	$0.28	$0.78

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 3-56 shows the markup component of average prices and of average monthly on-peak and off-peak prices using unadjusted offers. Table 3-57 shows the markup component of average prices and of average monthly on-peak and off-peak prices using adjusted offers. In 2015, when using adjusted cost-offers, $0.78 per MWh of the PJM day-ahead load-weighted average LMP was attributable to markup. In 2015, the peak markup component was highest in February, $4.51 per MWh using adjusted cost offers. Using adjusted cost-offers, the markup component in 2015 decreased in every month except February, May, June and October from 2014. Using adjusted cost-offers, the markup component decreased from $1.79 to -$0.29 in January.

67 See 18 CFR § 385.213 (2014).

Table 3-56 Monthly markup components of day-ahead (Unadjusted), load-weighted LMP: 2014 and 2015

	2014			2015		
	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
Jan	$1.03	$2.85	($0.88)	($1.98)	($1.27)	($2.66)
Feb	$0.34	$2.07	($1.47)	$1.39	$3.35	($0.62)
Mar	$0.14	($0.27)	$0.53	($0.43)	$0.49	($1.38)
Apr	($0.88)	$0.42	($2.37)	($0.79)	($0.06)	($1.63)
May	($0.99)	$0.07	($2.10)	$0.75	$0.70	$0.80
Jun	$0.03	$1.29	($1.45)	$1.66	$2.32	$0.85
Jul	($0.98)	($0.38)	($1.68)	($0.34)	$0.60	($1.53)
Aug	($0.70)	$0.07	($1.51)	$0.08	$0.90	($0.79)
Sep	($0.37)	$0.79	($1.64)	$0.94	$1.38	$0.44
Oct	($0.48)	$0.52	($1.69)	$2.68	$4.42	$0.77
Nov	($0.47)	$0.86	($1.61)	($0.30)	($0.05)	($0.54)
Dec	($1.02)	($0.36)	($1.72)	$0.07	($0.04)	$0.18
Annual	($0.34)	$0.68	($1.42)	$0.28	$1.07	($0.56)

Table 3-57 Monthly markup components of day-ahead (Adjusted), load-weighted LMP: 2014 and 2015

	2014			2015		
	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
Jan	$1.79	$3.41	$0.09	($0.29)	$0.21	($0.76)
Feb	$1.42	$2.84	($0.07)	$2.81	$4.51	$1.06
Mar	$1.31	$0.61	$1.98	$1.01	$1.79	$0.21
Apr	$0.51	$1.34	($0.45)	$0.50	$1.03	($0.11)
May	$0.23	$0.85	($0.41)	$0.75	$0.70	$0.80
Jun	$1.37	$2.30	$0.29	$1.66	$2.32	$0.85
Jul	$0.52	$0.92	$0.05	($0.34)	$0.60	($1.53)
Aug	$0.64	$1.23	$0.01	$0.08	$0.90	($0.79)
Sep	$1.04	$1.94	$0.05	$0.94	$1.38	$0.44
Oct	$0.89	$1.62	($0.01)	$2.68	$4.42	$0.77
Nov	$0.80	$1.75	($0.00)	($0.30)	($0.05)	($0.54)
Dec	$0.41	$0.92	($0.13)	$0.07	($0.04)	$0.18
Annual	$0.93	$1.67	$0.14	$0.78	$1.49	$0.03

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 3-58. The markup component of annual average day-ahead price using adjusted offers is shown for each zone in Table 3-59. The markup component of the average day-ahead price decreased in all zones from 2014 to 2015. The smallest zonal all hours average markup component using adjusted offers for 2015 was in the Met-Ed Zone, $0.47 per MWh, while the highest was in the AECO Control Zone, $1.15 per MWh. The smallest zonal on peak average markup was in the BGE Control Zone, $0.85 per MWh, while the highest was in the AECO Control Zone, $2.50 per MWh.

Table 3-58 Day-ahead, average, zonal markup component (Unadjusted): 2014 and 2015

	2014			2015		
	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
AECO	($0.11)	$0.96	($1.27)	$0.75	$2.18	($0.81)
AEP	($0.40)	$0.64	($1.48)	$0.25	$1.08	($0.62)
AP	($0.40)	$0.68	($1.53)	$0.19	$0.73	($0.39)
ATSI	($0.45)	$0.61	($1.59)	$0.10	$0.87	($0.74)
BGE	($0.30)	$0.77	($1.46)	$0.13	$0.40	($0.17)
ComEd	($0.43)	$0.41	($1.34)	$0.22	$1.12	($0.76)
DAY	($0.43)	$0.59	($1.53)	$0.17	$1.04	($0.78)
DEOK	($0.42)	$0.56	($1.44)	$0.16	$0.94	($0.67)
DLCO	($0.43)	$0.54	($1.48)	($0.02)	$0.66	($0.76)
Dominion	($0.36)	$0.68	($1.46)	$0.34	$0.86	($0.20)
DPL	($0.43)	$0.29	($1.21)	$0.68	$1.95	($0.67)
EKPC	($0.30)	$0.69	($1.28)	$0.29	$1.19	($0.62)
JCPL	($0.16)	$0.87	($1.33)	$0.54	$1.58	($0.66)
Met-Ed	($0.09)	$1.00	($1.28)	$0.04	$0.65	($0.61)
PECO	($0.05)	$1.08	($1.27)	$0.40	$1.43	($0.71)
PENELEC	($0.34)	$0.69	($1.50)	$0.23	$0.91	($0.50)
Pepco	($0.25)	$0.80	($1.45)	$0.56	$1.32	($0.27)
PPL	($0.14)	$0.97	($1.34)	$0.25	$1.11	($0.68)
PSEG	($0.14)	$0.93	($1.33)	$0.56	$1.67	($0.68)
RECO	($0.16)	$0.86	($1.36)	$0.64	$1.63	($0.54)

Table 3-59 Day-ahead, average, zonal markup component (Adjusted): 2014 and 2015

	2014			2015		
	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
AECO	$1.07	$1.87	$0.20	$1.15	$2.50	($0.32)
AEP	$0.90	$1.64	$0.12	$0.80	$1.55	$0.03
AP	$0.87	$1.65	$0.05	$0.73	$1.20	$0.23
ATSI	$0.85	$1.62	$0.03	$0.67	$1.36	($0.09)
BGE	$1.12	$1.91	$0.26	$0.66	$0.85	$0.45
ComEd	$0.86	$1.43	$0.25	$0.75	$1.59	($0.17)
DAY	$0.90	$1.63	$0.11	$0.73	$1.51	($0.12)
DEOK	$0.87	$1.55	$0.16	$0.71	$1.41	($0.03)
DLCO	$0.81	$1.44	$0.12	$0.52	$1.13	($0.14)
Dominion	$0.94	$1.71	$0.12	$0.84	$1.29	$0.38
DPL	$0.74	$1.21	$0.25	$1.10	$2.26	($0.15)
EKPC	$0.95	$1.64	$0.26	$0.87	$1.66	$0.07
JCPL	$1.04	$1.82	$0.16	$0.94	$1.92	($0.16)
Met-Ed	$1.08	$1.92	$0.17	$0.47	$1.00	($0.10)
PECO	$1.11	$1.97	$0.17	$0.80	$1.76	($0.23)
PENELEC	$0.88	$1.64	$0.01	$0.71	$1.30	$0.09
Pepco	$1.10	$1.90	$0.21	$1.08	$1.77	$0.32
PPL	$1.02	$1.87	$0.09	$0.70	$1.48	($0.15)
PSEG	$1.00	$1.81	$0.09	$0.95	$1.98	($0.21)
RECO	$0.96	$1.74	$0.05	$1.03	$1.95	($0.06)

Markup by Day-Ahead Price Levels

Table 3-60 and Table 3-61 show the average markup component of observed prices, 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 3-60 Average, day-ahead markup (By LMP category, unadjusted): 2014 and 2015

	2014		2015	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $25	($2.75)	9.7%	($0.76)	30.3%
$25 to $50	($1.19)	71.3%	$0.21	59.9%
$50 to $75	$1.33	12.4%	$2.91	5.3%
$75 to $100	($0.49)	2.4%	($2.20)	2.3%
$100 to $125	($6.74)	0.8%	$1.16	1.1%
$125 to $150	$5.79	0.6%	$10.37	0.5%
>= $150	$10.52	2.7%	$12.53	0.7%

Table 3-61 Average, day-ahead markup (By LMP category, adjusted): 2014 and 2015

	2014		2015	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $25	($1.17)	9.7%	($0.57)	30.3%
$25 to $50	$0.57	71.3%	$0.93	59.9%
$50 to $75	$2.35	12.4%	$3.45	5.3%
$75 to $100	($0.03)	2.4%	($1.60)	2.3%
$100 to $125	($6.28)	0.8%	$1.81	1.1%
$125 to $150	$6.23	0.6%	$11.02	0.5%
>= $150	$11.42	2.7%	$12.89	0.7%

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 31.9 percent and 31.5 percent lower in 2015 than in 2014 as a result of lower fuel costs and lower demand in 2015. Coal and natural gas prices decreased in 2015. Comparing fuel prices in 2015 to 2014, the price of Northern Appalachian coal was 21.3 percent lower; the price of Central Appalachian coal was 22.7 percent lower; the price of Powder River Basin coal was 12.6 percent lower; the price of eastern natural gas was 42.6 percent lower; and the price of western natural gas was 49.5 percent lower.

PJM real-time energy market prices decreased in 2015 compared to 2014. The average LMP was 30.7 percent lower in 2015 than in 2014, $33.39 per MWh versus $48.22 per MWh. The load-weighted average LMP was 31.89 percent lower in 2015 than in 2014, $36.16 per MWh versus $53.14 per MWh.

The fuel-cost adjusted, load-weighted, average LMP in 2015 was 15.9 percent higher than the load-weighted, average LMP for 2015. If fuel costs in 2015 had been the same as in 2014, holding everything else constant, the load-weighted LMP would have been higher, $41.91 per MWh instead of the observed $36.16 per MWh.

PJM day-ahead energy market prices decreased in 2015 compared to 2014. The average LMP was 30.6 percent lower in 2015 than in 2014, $34.12 per MWh versus $49.15 per MWh. The day-ahead load-weighted average LMP was 31.5 percent lower in 2015 than in 2014, $36.73 per MWh versus $53.62 per MWh.[68]

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.[69] 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 occasionally the LMPs at some pricing nodes exceed $1,000 per MWh, the cap on the generators' offer price in the PJM market.[70]

Real-Time LMP

Real-time average LMP is the hourly average LMP for the PJM Real-Time Energy Market.[71]

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

69 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.

70 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).

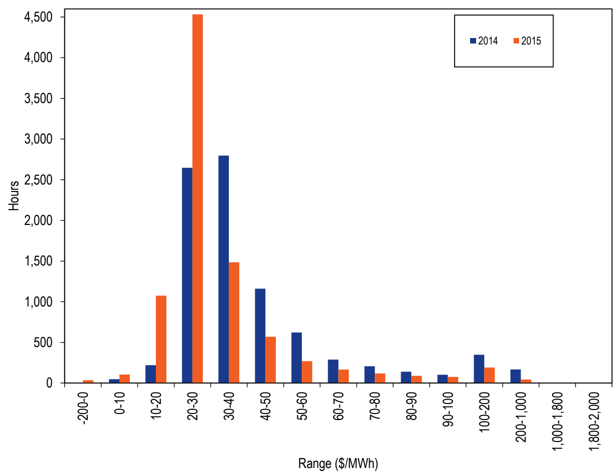
71 See the *MMU Technical Reference for the PJM Markets*, at "Calculating Locational Marginal Price," for detailed definition of Real-Time LMP. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

Real-Time Average LMP

PJM Real-Time Average LMP Duration

Figure 3-33 shows the hourly distribution of PJM real-time average LMP for 2014 and 2015. In 2014, there were five hours in January in which the PJM real-time average LMP was greater than $1,000 and less than $1,800, and one hour in which the real-time LMP was greater than $1,800.

Figure 3-33 Average LMP for the PJM Real-Time Energy Market: 2014 and 2015[72]



PJM Real-Time, Average LMP

Table 3-62 shows the PJM real-time, average LMP for each year of the 18 year period 1998 to 2015.[73]

Table 3-62 PJM real-time, average LMP (Dollars per MWh): 1998 through 2015

	Real-Time LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$21.72	$16.60	$31.45	NA	NA	NA
1999	$28.32	$17.88	$72.42	30.4%	7.7%	130.3%
2000	$28.14	$19.11	$25.69	(0.6%)	6.9%	(64.5%)
2001	$32.38	$22.98	$45.03	15.1%	20.3%	75.3%
2002	$28.30	$21.08	$22.41	(12.6%)	(8.3%)	(50.2%)
2003	$38.28	$30.79	$24.71	35.2%	46.1%	10.3%
2004	$42.40	$38.30	$21.12	10.8%	24.4%	(14.5%)
2005	$58.08	$47.18	$35.91	37.0%	23.2%	70.0%
2006	$49.27	$41.45	$32.71	(15.2%)	(12.1%)	(8.9%)
2007	$57.58	$49.92	$34.60	16.9%	20.4%	5.8%
2008	$66.40	$55.53	$38.62	15.3%	11.2%	11.6%
2009	$37.08	$32.71	$17.12	(44.1%)	(41.1%)	(55.7%)
2010	$44.83	$36.88	$26.20	20.9%	12.7%	53.1%
2011	$42.84	$35.38	$29.03	(4.4%)	(4.1%)	10.8%
2012	$33.11	$29.53	$20.67	(22.7%)	(16.5%)	(28.8%)
2013	$36.55	$32.25	$20.57	10.4%	9.2%	(0.5%)
2014	$48.22	$34.46	$65.08	31.9%	6.8%	216.4%
2015	$33.39	$26.61	$27.80	(30.7%)	(22.8%)	(57.3%)

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. The real-time, load-weighted, average LMP decreased by 31.9 percent compared to 2014.

PJM Real-Time, Load-Weighted, Average LMP

Table 3-63 shows the PJM real-time, load-weighted, average LMP for each year of the 18 year period 1998 to 2015.

72 The data used in the version of this table in the *2014 Quarterly State of the Market Report for PJM: January through March* did not include LMP values greater than $1,000, but this table reflects those LMP values.

73 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 3-63 PJM real-time, load-weighted, average LMP (Dollars per MWh): 1998 through 2015

	Real-Time, Load-Weighted, Average LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$24.16	$17.60	$39.29	NA	NA	NA
1999	$34.07	$19.02	$91.49	41.0%	8.1%	132.8%
2000	$30.72	$20.51	$28.38	(9.8%)	7.9%	(69.0%)
2001	$36.65	$25.08	$57.26	19.3%	22.3%	101.8%
2002	$31.60	$23.40	$26.75	(13.8%)	(6.7%)	(53.3%)
2003	$41.23	$34.96	$25.40	30.5%	49.4%	(5.0%)
2004	$44.34	$40.16	$21.25	7.5%	14.9%	(16.3%)
2005	$63.46	$52.93	$38.10	43.1%	31.8%	79.3%
2006	$53.35	$44.40	$37.81	(15.9%)	(16.1%)	(0.7%)
2007	$61.66	$54.66	$36.94	15.6%	23.1%	(2.3%)
2008	$71.13	$59.54	$40.97	15.4%	8.9%	10.9%
2009	$39.05	$34.23	$18.21	(45.1%)	(42.5%)	(55.6%)
2010	$48.35	$39.13	$28.90	23.8%	14.3%	58.7%
2011	$45.94	$36.54	$33.47	(5.0%)	(6.6%)	15.8%
2012	$35.23	$30.43	$23.66	(23.3%)	(16.7%)	(29.3%)
2013	$38.66	$33.25	$23.78	9.7%	9.3%	0.5%
2014	$53.14	$36.20	$76.20	37.4%	8.9%	220.4%
2015	$36.16	$27.66	$31.06	(31.9%)	(23.6%)	(59.2%)

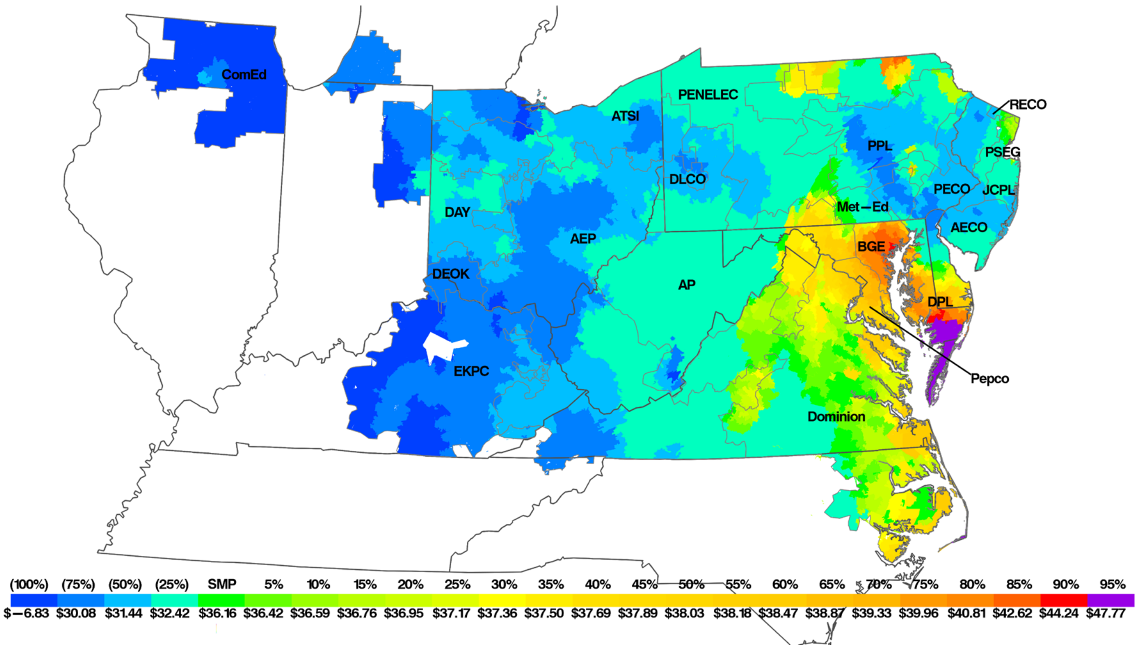
Table 3-64 shows zonal real-time, and real-time, load-weighted, average LMP for 2014 and 2015.

Table 3-64 Zone real-time and real-time, load-weighted, average LMP (Dollars per MWh): 2014 and 2015

	Real-Time Average LMP			Real-Time, Load-Weighted, Average LMP		
Zone	2014 Average	2015 Average	Percent Change	2014 Average	2015 Average	Percent Change
AECO	$51.17	$32.86	(35.8%)	$55.77	$35.85	(35.7%)
AEP	$44.03	$31.76	(27.9%)	$47.81	$33.90	(29.1%)
AP	$47.60	$34.78	(26.9%)	$52.94	$38.04	(28.1%)
ATSI	$45.39	$32.10	(29.3%)	$48.60	$34.00	(30.0%)
BGE	$58.81	$42.84	(27.2%)	$67.78	$47.22	(30.3%)
ComEd	$39.54	$28.21	(28.7%)	$42.04	$29.85	(29.0%)
Day	$43.77	$32.11	(26.6%)	$47.36	$34.20	(27.8%)
DEOK	$41.68	$31.19	(25.2%)	$45.00	$33.28	(26.0%)
DLCO	$41.55	$30.45	(26.7%)	$44.22	$32.21	(27.2%)
Dominion	$54.50	$37.24	(31.7%)	$62.99	$41.42	(34.2%)
DPL	$41.55	$30.45	(26.7%)	$65.03	$42.27	(35.0%)
EKPC	$41.75	$30.10	(27.9%)	$47.88	$32.93	(31.2%)
JCPL	$50.97	$32.36	(36.5%)	$56.07	$35.65	(36.4%)
Met-Ed	$49.60	$32.17	(35.1%)	$56.08	$35.79	(36.2%)
PECO	$50.21	$31.80	(36.7%)	$55.94	$35.11	(37.2%)
PENELEC	$47.63	$33.47	(29.7%)	$51.90	$36.13	(30.4%)
Pepco	$57.34	$39.21	(31.6%)	$65.61	$43.04	(34.4%)
PPL	$49.62	$31.93	(35.6%)	$56.97	$35.95	(36.9%)
PSEG	$53.71	$34.38	(36.0%)	$57.90	$36.97	(36.2%)
RECO	$52.96	$35.02	(33.9%)	$56.79	$37.58	(33.8%)
PJM	$48.22	$33.39	(30.7%)	$53.14	$36.16	(31.9%)

Figure 3-34 is a contour map of the real-time, load-weighted, average LMP in 2015. 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.

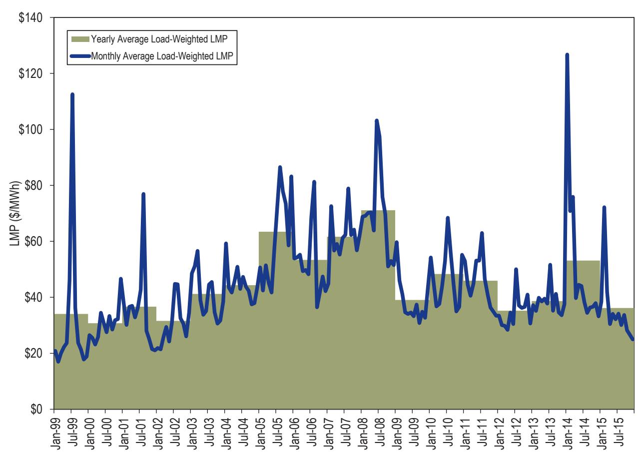
Figure 3-34 PJM real-time, load-weighted, average LMP: 2015



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

Figure 3-35 shows the PJM real-time monthly and annual load-weighted LMP for 1999 through 2015. PJM real-time monthly load-weighted average LMP in December 2015 was $24.95, which is the lowest real-time monthly load-weighted average LMP since May 2002 at $24.19.

Figure 3-35 PJM real-time, monthly and annual, load-weighted, average LMP: 1999 through 2015



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. Coal and natural gas prices decreased in 2015. Comparing fuel prices in 2015 to 2014, the price of Northern Appalachian coal was 21.3 percent lower; the price of Central Appalachian coal was 22.7 percent lower; the price of Powder River Basin coal was 12.6 percent lower; the price of eastern natural gas was 42.6 percent lower; and the price of western natural gas was 49.5 percent lower. Figure 3-36 shows monthly average spot fuel prices.[74]

74 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.

Figure 3-36 Spot average fuel price comparison with fuel delivery charges: 2012 through 2015 ($/MMBtu)

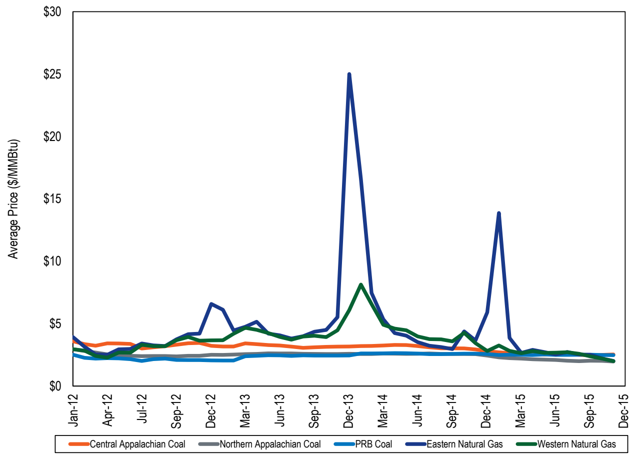


Table 3-65 compares the 2015 PJM real time fuel-cost adjusted, load-weighted, average LMP to the 2015 load-weighted, average LMP. The real time fuel-cost adjusted, load-weighted, average LMP for 2015 was 15.9 percent higher than the real time load-weighted, average LMP for 2015. The real-time, fuel-cost adjusted, load-weighted, average LMP for 2015 was 21.1 percent lower than the real time load-weighted LMP for 2014. If fuel costs in 2015 had been the same as in 2014, holding everything else constant, the real time load-weighted LMP in 2015 would have been higher, $41.91 per MWh instead of the observed $36.16 per MWh.

Table 3-65 PJM real-time annual, fuel-cost adjusted, load-weighted average LMP (Dollars per MWh): year over year

	2015 Load-Weighted LMP	2015 Fuel-Cost-Adjusted, Load-Weighted LMP	Change
Average	$36.16	$41.91	15.9%
	2014 Load-Weighted LMP	2015 Fuel-Cost-Adjusted, Load-Weighted LMP	Change
Average	$53.14	$41.91	(21.1%)
	2014 Load-Weighted LMP	2015 Load-Weighted LMP	Change
Average	$53.14	$36.16	(31.9%)

Table 3-66 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 2015. Table 3-66 shows that lower coal, natural gas and oil prices explain almost all of the fuel-cost related decrease in the real time annual load-weighted average LMP in 2015. Unlike oil and natural gas, there was no substantial change in the price of coal from 2014 to 2015. However, coal units' offer prices were generally lower in 2015 compared to their offers in 2014, particularly the high offer prices during the cold weather days in January and March of 2014.

Table 3-66 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	($1.75)	30.4%
Gas	($3.40)	59.1%
Municipal Waste	($0.00)	0.0%
Oil	($0.58)	10.1%
Other	($0.02)	0.3%
Uranium	$0.00	(0.0%)
Wind	($0.00)	0.0%
Total	($5.75)	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.[75] 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

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

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

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, PJM has been using a procedure called constraint relaxation logic to prevent the penalty factors from setting the shadow price of the constraint. The result is that the transmission penalty factor does not set the shadow price. The details of PJM's logic and practice are not entirely clear. But in 2015, for all transmission constraints for which a penalty factor at or above $2,000 per MWh was used, 41 percent of the constraints' shadow prices were within ten 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, and when the transmission penalty factors will be used to set the shadow price.

The components of LMP are shown in Table 3-67, including markup using unadjusted cost offers.[77] Table 3-67 shows that for 2015, 43.2 percent of the load-weighted LMP was the result of coal costs, 27.2 percent was the result of gas costs and 2.32 percent was the result of the cost of emission allowances. Markup was 0.3 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 2015, nearly nine 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 2015 and 2014.

76 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 RTO-wide shortage of synchronized reserve.

77 These components are explained in the *Technical Reference for PJM Markets*, at "Calculation and Use of Generator Sensitivity/Unit Participation Factors."

Table 3-67 Components of PJM real-time (Unadjusted), load-weighted, average LMP: 2014 and 2015

	2014		2015		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change Percent
Coal	$17.73	33.4%	$15.62	43.2%	9.8%
Gas	$18.71	35.2%	$9.85	27.2%	(8.0%)
Ten Percent Adder	$3.77	7.1%	$3.02	8.4%	1.3%
VOM	$2.65	5.0%	$2.38	6.6%	1.6%
Oil	$2.80	5.3%	$1.25	3.5%	(1.8%)
Ancillary Service Redispatch Cost	$0.52	1.0%	$1.06	2.9%	2.0%
LPA Rounding Difference	$0.07	0.1%	$0.94	2.6%	2.5%
NA	$1.56	2.9%	$0.89	2.4%	(0.5%)
SO_2 Cost	$0.01	0.0%	$0.35	1.0%	0.9%
NO_x Cost	$0.13	0.2%	$0.29	0.8%	0.6%
Increase Generation Adder	$0.69	1.3%	$0.24	0.7%	(0.6%)
CO_2 Cost	$0.23	0.4%	$0.21	0.6%	0.1%
Other	$0.03	0.1%	$0.15	0.4%	0.4%
Markup	$1.88	3.5%	$0.12	0.3%	(3.2%)
Municipal Waste	$0.02	0.0%	$0.01	0.0%	(0.0%)
Market-to-Market Adder	($0.00)	(0.0%)	$0.01	0.0%	0.0%
FMU Adder	$0.62	1.2%	$0.00	0.0%	(1.2%)
Emergency DR Adder	$1.83	3.4%	$0.00	0.0%	(3.4%)
Scarcity Adder	$0.10	0.2%	$0.00	0.0%	(0.2%)
Constraint Violation Adder	$0.00	0.0%	($0.00)	(0.0%)	(0.0%)
Uranium	($0.01)	(0.0%)	($0.00)	(0.0%)	0.0%
Decrease Generation Adder	($0.17)	(0.3%)	($0.06)	(0.2%)	0.2%
Wind	($0.01)	(0.0%)	($0.07)	(0.2%)	(0.2%)
LPA-SCED Differential	($0.01)	(0.0%)	($0.11)	(0.3%)	(0.3%)
Total	$53.14	100.0%	$36.16	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 3-67 and Table 3-71) markup is simply the difference between the price offer and the cost offer. In the second approach, (Table 3-68 and Table 3-72) the 10 percent markup is removed from the cost offers of coal units.

The components of LMP are shown in Table 3-68, including markup using adjusted cost offers.

Table 3-68 Components of PJM real-time (Adjusted), load-weighted, average LMP: 2014 and 2015

	2014		2015		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change Percent
Coal	$17.73	33.4%	$15.62	43.2%	9.8%
Gas	$18.71	35.2%	$9.85	27.2%	(8.0%)
VOM	$2.65	5.0%	$2.38	6.6%	1.6%
Markup	$3.32	6.2%	$1.75	4.8%	(1.4%)
Ten Percent Adder	$2.33	4.4%	$1.40	3.9%	(0.5%)
Oil	$2.80	5.3%	$1.25	3.5%	(1.8%)
Ancillary Service Redispatch Cost	$0.52	1.0%	$1.06	2.9%	2.0%
LPA Rounding Difference	$0.07	0.1%	$0.94	2.6%	2.5%
NA	$1.56	2.9%	$0.89	2.4%	(0.5%)
SO_2 Cost	$0.01	0.0%	$0.35	1.0%	0.9%
NO_x Cost	$0.13	0.2%	$0.29	0.8%	0.6%
Increase Generation Adder	$0.69	1.3%	$0.24	0.7%	(0.6%)
CO_2 Cost	$0.23	0.4%	$0.21	0.6%	0.1%
Other	$0.03	0.1%	$0.15	0.4%	0.4%
Municipal Waste	$0.02	0.0%	$0.01	0.0%	(0.0%)
Market-to-Market Adder	($0.00)	(0.0%)	$0.01	0.0%	0.0%
FMU Adder	$0.62	1.2%	$0.00	0.0%	(1.2%)
Emergency DR Adder	$1.83	3.4%	$0.00	0.0%	(3.4%)
Scarcity Adder	$0.10	0.2%	$0.00	0.0%	(0.2%)
Constraint Violation Adder	$0.00	0.0%	($0.00)	(0.0%)	(0.0%)
Uranium	($0.01)	(0.0%)	($0.00)	(0.0%)	0.0%
Decrease Generation Adder	($0.17)	(0.3%)	($0.06)	(0.2%)	0.2%
Wind	($0.01)	(0.0%)	($0.07)	(0.2%)	(0.2%)
LPA-SCED Differential	($0.01)	(0.0%)	($0.11)	(0.3%)	(0.3%)
Total	$53.14	100.0%	$36.16	100.0%	0.0%

Day-Ahead LMP

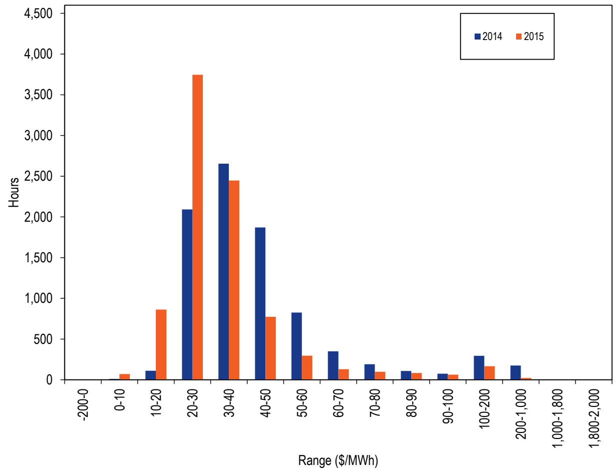
Day-ahead average LMP is the hourly average LMP for the PJM Day-Ahead Energy Market.[78]

Day-Ahead Average LMP

PJM Day-Ahead Average LMP Duration

Figure 3-37 shows the hourly distribution of PJM day-ahead average LMP for 2014 and 2015.

Figure 3-37 Average LMP for the PJM Day-Ahead Energy Market: 2014 and 2015



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>.

PJM Day-Ahead, Average LMP

Table 3-69 shows the PJM day-ahead, average LMP for each year of the 15-year period 2001 through 2015.

Table 3-69 PJM day-ahead, average LMP (Dollars per MWh): 2001 through 2015

	Day-Ahead LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2001	$32.75	$27.05	$30.42	NA	NA	NA
2002	$28.46	$23.28	$17.68	(13.1%)	(14.0%)	(41.9%)
2003	$38.73	$35.22	$20.84	36.1%	51.3%	17.8%
2004	$41.43	$40.36	$16.60	7.0%	14.6%	(20.4%)
2005	$57.89	$50.08	$30.04	39.7%	24.1%	81.0%
2006	$48.10	$44.21	$23.42	(16.9%)	(11.7%)	(22.0%)
2007	$54.67	$52.34	$23.99	13.7%	18.4%	2.4%
2008	$66.12	$58.93	$30.87	20.9%	12.6%	28.7%
2009	$37.00	$35.16	$13.39	(44.0%)	(40.3%)	(56.6%)
2010	$44.57	$39.97	$18.83	20.5%	13.7%	40.6%
2011	$42.52	$38.13	$20.48	(4.6%)	(4.6%)	8.8%
2012	$32.79	$30.89	$13.27	(22.9%)	(19.0%)	(35.2%)
2013	$37.15	$34.63	$15.46	13.3%	12.1%	16.5%
2014	$49.15	$38.10	$51.88	32.3%	10.0%	235.6%
2015	$34.12	$29.09	$22.59	(30.6%)	(23.7%)	(56.5%)

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 3-70 shows the PJM day-ahead, load-weighted, average LMP for each year of the 15-year period 2001 through 2015.

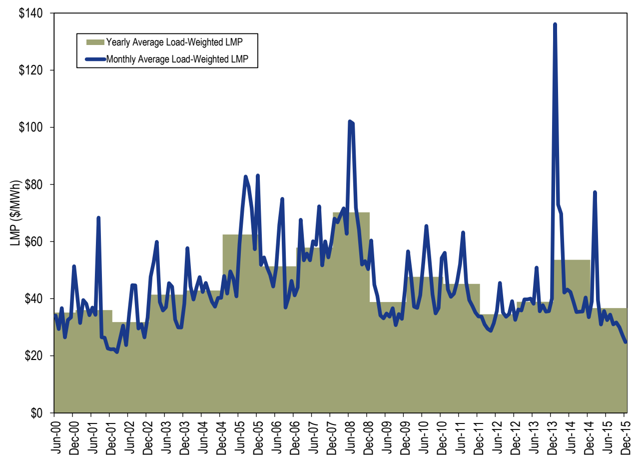
Table 3-70 PJM day-ahead, load-weighted, average LMP (Dollars per MWh): 2001 through 2015

	Day-Ahead, Load-Weighted, Average LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2001	$36.01	$29.02	$37.48	NA	NA	NA
2002	$31.80	$26.00	$20.68	(11.7%)	(10.4%)	(44.8%)
2003	$41.43	$38.29	$21.32	30.3%	47.3%	3.1%
2004	$42.87	$41.96	$16.32	3.5%	9.6%	(23.4%)
2005	$62.50	$54.74	$31.72	45.8%	30.4%	94.3%
2006	$51.33	$46.72	$26.45	(17.9%)	(14.6%)	(16.6%)
2007	$57.88	$55.91	$25.02	12.8%	19.7%	(5.4%)
2008	$70.25	$62.91	$33.14	21.4%	12.5%	32.4%
2009	$38.82	$36.67	$14.03	(44.7%)	(41.7%)	(57.7%)
2010	$47.65	$42.06	$20.59	22.7%	14.7%	46.8%
2011	$45.19	$39.66	$24.05	(5.2%)	(5.7%)	16.8%
2012	$34.55	$31.84	$15.48	(23.5%)	(19.7%)	(35.6%)
2013	$38.93	$35.77	$18.05	12.7%	12.3%	16.6%
2014	$53.62	$39.84	$59.62	37.8%	11.4%	230.4%
2015	$36.73	$30.60	$25.46	(31.5%)	(23.2%)	(57.3%)

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

Figure 3-38 shows the PJM day-ahead, monthly and annual, load-weighted LMP from June 2000 through December 2015.[79] The PJM day-ahead monthly load-weighted average LMP in December 2015 was $24.82, which is the lowest day-ahead monthly load-weighted average since May 2002 at $23.74.

Figure 3-38 Day-ahead, monthly and annual, load-weighted, average LMP: June 2000 through December 2015



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

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.

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.[80] 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.

Table 3-71 shows the components of the PJM day-ahead, annual, load-weighted average LMP. In 2015, 29.6 percent of the load-weighted LMP was the result of coal cost, 14.3 percent of the load-weighted LMP was the result of gas cost, 4.3 percent was the result of the up to congestion transaction cost, 22.5 percent was the result of DEC bid cost and 11.6 percent was the result of INC bid cost. The contribution of up to congestion transactions decreased on September 8, 2014, as a result of the FERC's UTC uplift refund notice which became effective on that date.[81]

Table 3-71 Components of PJM day-ahead, (unadjusted), load-weighted, average LMP (Dollars per MWh): 2014 and 2015

	2014		2015		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change Percent
Coal	$11.30	21.1%	$10.86	29.6%	8.5%
DEC	$9.20	17.2%	$8.27	22.5%	5.4%
Gas	$10.71	20.0%	$5.25	14.3%	(5.7%)
INC	$8.16	15.2%	$4.27	11.6%	(3.6%)
Ten Percent Cost Adder	$2.45	4.6%	$1.88	5.1%	0.6%
Up to Congestion Transaction	$6.21	11.6%	$1.56	4.3%	(7.3%)
VOM	$1.46	2.7%	$1.40	3.8%	1.1%
Dispatchable Transaction	$2.25	4.2%	$1.05	2.9%	(1.3%)
Oil	$0.78	1.5%	$0.87	2.4%	0.9%
Markup	($0.34)	(0.6%)	$0.28	0.8%	1.4%
DASR LOC Adder	($0.03)	(0.1%)	$0.28	0.7%	0.8%
SO_2	$0.01	0.0%	$0.22	0.6%	0.6%
DASR Offer Adder	$0.05	0.1%	$0.17	0.5%	0.4%
NO_x	$0.08	0.1%	$0.16	0.4%	0.3%
CO_2	$0.15	0.3%	$0.09	0.2%	(0.0%)
Price Sensitive Demand	$0.85	1.6%	$0.04	0.1%	(1.5%)
Municipal Waste	$0.02	0.0%	$0.01	0.0%	(0.0%)
Other	$0.00	0.0%	$0.00	0.0%	0.0%
Constrained Off	$0.00	0.0%	$0.00	0.0%	0.0%
Wind	($0.01)	(0.0%)	($0.04)	(0.1%)	(0.1%)
FMU Adder	$0.33	0.6%	$0.00	0.0%	(0.6%)
NA	($0.01)	(0.0%)	$0.11	0.3%	0.3%
Total	$53.62	100.0%	$36.73	100.0%	0.0%

Table 3-72 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 units.

80 New Jersey withdrew from RGGI, effective January 1, 2012.
81 See 18 CFR § 385.213 (2014).

Table 3-72 Components of PJM day-ahead, (adjusted), load-weighted, average LMP (Dollars per MWh): 2014 and 2015

	2014		2015		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change Percent
Coal	$11.27	21.0%	$10.86	29.6%	8.5%
DEC	$9.20	17.2%	$8.27	22.5%	5.4%
Gas	$10.71	20.0%	$5.25	14.3%	(5.7%)
INC	$8.16	15.2%	$4.27	11.6%	(3.6%)
Up to Congestion Transaction	$6.21	11.6%	$1.56	4.3%	(7.3%)
VOM	$1.46	2.7%	$1.40	3.8%	1.1%
Ten Percent Cost Adder	$1.21	2.3%	$1.38	3.7%	1.5%
Dispatchable Transaction	$2.25	4.2%	$1.05	2.9%	(1.3%)
Oil	$0.78	1.4%	$0.87	2.4%	0.9%
Markup	$0.93	1.7%	$0.78	2.1%	0.4%
DASR LOC Adder	($0.03)	(0.1%)	$0.28	0.7%	0.8%
SO_2	$0.01	0.0%	$0.22	0.6%	0.6%
DASR Offer Adder	$0.05	0.1%	$0.17	0.5%	0.4%
NO_x	$0.08	0.1%	$0.16	0.4%	0.3%
CO_2	$0.15	0.3%	$0.09	0.2%	(0.0%)
Price Sensitive Demand	$0.85	1.6%	$0.04	0.1%	(1.5%)
Municipal Waste	$0.02	0.0%	$0.01	0.0%	(0.0%)
Other	$0.00	0.0%	$0.00	0.0%	0.0%
Constrained Off	$0.00	0.0%	$0.00	0.0%	0.0%
Wind	($0.01)	(0.0%)	($0.04)	(0.1%)	(0.1%)
FMU Adder	$0.33	0.6%	$0.00	0.0%	(0.6%)
NA	($0.01)	(0.0%)	$0.11	0.3%	0.3%
Total	$53.62	100.0%	$36.73	100.0%	0.0%

Price Convergence

The introduction of the PJM Day-Ahead Energy Market created the possibility that competition, exercised through the use of virtual offers and bids, would tend to cause prices in the Day-Ahead and Real-Time Energy Markets to converge. 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 by improving day-ahead commitments relative to real-time system requirements.

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 arbitrage 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.

Profitability is a less reliable indicator of whether a UTC contributes to price convergence than for INCs and DECs. 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. A profitable UTC can contribute to both price divergence on one side and to price convergence on the other side.

Table 3-73 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 2014 and 2015. In 2015, 51.7 percent of all cleared UTC transactions were net profitable, with 67.4 percent of the source side profitable and 33.8 percent of the sink side profitable.

Table 3-73 Cleared UTC profitability by source and sink point: 2014 and 2015[82]

	Cleared UTCs	Profitable UTCs	UTC Profitable at Source Bus	UTC Profitable at Sink Bus	Profitable UTC	Profitable Source	Profitable Sink
2014	19,876,521	11,029,405	13,427,449	6,713,638	55.5%	67.6%	33.8%
2015	10,052,055	5,198,147	6,771,210	3,394,829	51.7%	67.4%	33.8%

Table 3-74 Day-ahead and real-time average LMP (Dollars per MWh): 2014 and 2015[83]

	2014				2015			
	Day Ahead	Real Time	Difference	Percent of Real Time	Day Ahead	Real Time	Difference	Percent of Real Time
Average	$49.15	$48.22	($0.93)	(1.9%)	$34.12	$33.39	($0.73)	(2.2%)
Median	$38.10	$34.46	($3.64)	(10.6%)	$29.09	$26.61	($2.47)	(9.3%)
Standard deviation	$51.88	$65.08	$13.20	20.3%	$22.59	$27.80	$5.22	18.8%
Peak average	$60.65	$59.12	($1.54)	(2.6%)	$40.97	$39.44	($1.53)	(3.9%)
Peak median	$44.55	$40.50	($4.05)	(10.0%)	$33.69	$29.95	($3.74)	(12.5%)
Peak standard deviation	$64.56	$81.78	$17.22	21.1%	$26.30	$30.23	$3.93	13.0%
Off peak average	$39.12	$38.72	($0.41)	(1.1%)	$28.11	$28.08	($0.03)	(0.1%)
Off peak median	$31.37	$29.39	($1.98)	(6.7%)	$24.51	$23.62	($0.90)	(3.8%)
Off peak standard deviation	$34.48	$43.64	$9.16	21.0%	$16.54	$24.28	$7.74	31.9%

There are incentives to use virtual transactions to arbitrage 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 3-40).

The analysis of the data from September 1, 2013 through September 31, 2015 period 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 3-74 shows that the difference between the average real-time price and the average day-ahead price was -$0.93 per MWh in 2014, and -$0.73 per MWh in 2015. The difference between average peak real-time price and the average peak day-ahead price was -$1.54 per MWh in 2014 and -$1.53 per MWh in 2015.

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 3-75 shows the difference between the real-time and the day-ahead energy market prices for each year of the 15-year period 2001 to 2015.

Table 3-75 Day-ahead and real-time average LMP (Dollars per MWh): 2001 through 2015

	Day Ahead	Real Time	Difference	Percent of Real Time
2001	$32.75	$32.38	($0.37)	(1.1%)
2002	$28.46	$28.30	($0.16)	(0.6%)
2003	$38.73	$38.28	($0.45)	(1.2%)
2004	$41.43	$42.40	$0.97	2.3%
2005	$57.89	$58.08	$0.18	0.3%
2006	$48.10	$49.27	$1.17	2.4%
2007	$54.67	$57.58	$2.90	5.3%
2008	$66.12	$66.40	$0.28	0.4%
2009	$37.00	$37.08	$0.08	0.2%
2010	$44.57	$44.83	$0.26	0.6%
2011	$42.52	$42.84	$0.32	0.7%
2012	$32.79	$33.11	$0.32	1.0%
2013	$37.15	$36.55	($0.60)	(1.6%)
2014	$49.15	$48.22	($0.93)	(1.9%)
2015	$34.12	$33.39	($0.73)	(2.1%)

82 Calculations exclude PJM administrative charges.
83 The averages used are the annual average of the hourly average PJM prices for day-ahead and real-time.

Table 3-76 provides frequency distributions of the differences between PJM real-time hourly LMP and PJM day-ahead hourly LMP for 2007 through 2015.

Table 3-76 Frequency distribution by hours of PJM real-time LMP minus day-ahead LMP (Dollars per MWh): 2007 through 2015

	2007		2008		2009		2010		2011	
LMP	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%
($1,000) to ($750)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
($750) to ($500)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
($500) to ($450)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
($450) to ($400)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
($400) to ($350)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
($350) to ($300)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
($300) to ($250)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
($250) to ($200)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
($200) to ($150)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	1	0.01%
($150) to ($100)	0	0.00%	1	0.01%	0	0.00%	0	0.00%	2	0.03%
($100) to ($50)	33	0.38%	88	1.01%	3	0.03%	13	0.15%	49	0.59%
($50) to $0	4,600	52.89%	5,120	59.30%	5,108	58.34%	5,543	63.42%	5,614	64.68%
$0 to $50	3,827	96.58%	3,247	96.27%	3,603	99.47%	3,004	97.72%	2,880	97.56%
$50 to $100	255	99.49%	284	99.50%	41	99.94%	164	99.59%	185	99.67%
$100 to $150	31	99.84%	37	99.92%	5	100.00%	25	99.87%	21	99.91%
$150 to $200	5	99.90%	4	99.97%	0	100.00%	9	99.98%	2	99.93%
$200 to $250	1	99.91%	2	99.99%	0	100.00%	2	100.00%	3	99.97%
$250 to $300	3	99.94%	0	99.99%	0	100.00%	0	100.00%	0	99.97%
$300 to $350	2	99.97%	1	100.00%	0	100.00%	0	100.00%	0	99.97%
$350 to $400	1	99.98%	0	100.00%	0	100.00%	0	100.00%	0	99.97%
$400 to $450	1	99.99%	0	100.00%	0	100.00%	0	100.00%	0	99.97%
$450 to $500	1	100.00%	0	100.00%	0	100.00%	0	100.00%	0	99.97%
$500 to $750	0	100.00%	0	100.00%	0	100.00%	0	100.00%	3	100.00%
$750 to $1,000	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%
$1,000 to $1,250	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%
>= $1,250	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%

Figure 3-39 shows the hourly differences between day-ahead and real-time hourly LMP in of 2015.

Figure 3-39 Real-time hourly LMP minus day-ahead hourly LMP: 2015

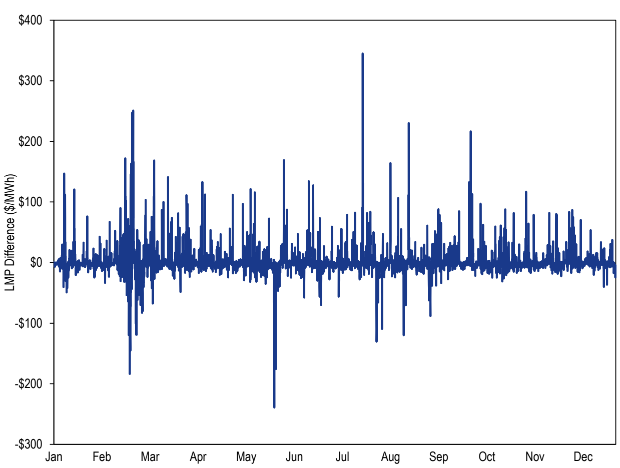


Figure 3-40 shows the monthly average differences between the day-ahead and real-time LMP in 2015.

Figure 3-40 Monthly average of real-time minus day-ahead LMP: January 2014 through December 2015

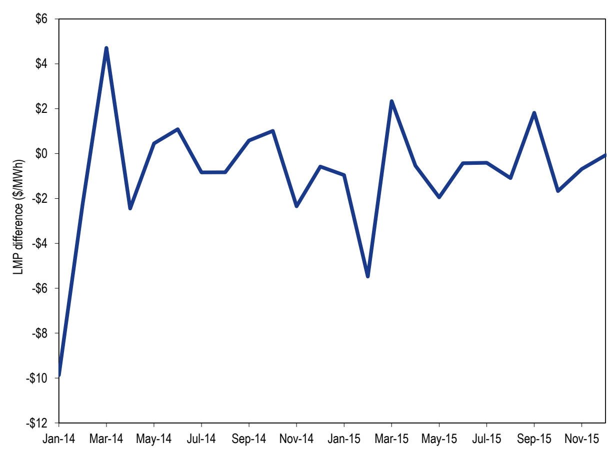
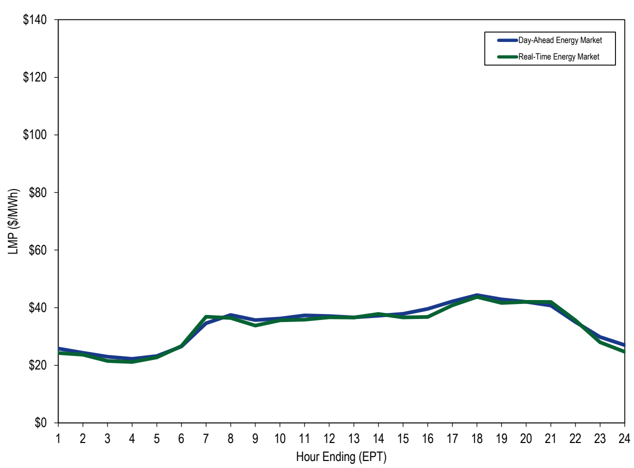


Table 3-76 Frequency distribution by hours of PJM real-time LMP minus day-ahead LMP (Dollars per MWh): 2007 through 2015 *(continued)*

	2012		2013		2014		2015	
LMP	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%
($1,000) to ($750)	0	0.00%	0	0.00%	2	0.02%	0	0.00%
($750) to ($500)	0	0.00%	0	0.00%	3	0.06%	0	0.00%
($500) to ($450)	0	0.00%	0	0.00%	1	0.07%	0	0.00%
($450) to ($400)	0	0.00%	0	0.00%	6	0.14%	0	0.00%
($400) to ($350)	0	0.00%	0	0.00%	5	0.19%	0	0.00%
($350) to ($300)	0	0.00%	0	0.00%	5	0.25%	0	0.00%
($300) to ($250)	0	0.00%	0	0.00%	6	0.32%	0	0.00%
($250) to ($200)	1	0.01%	1	0.01%	14	0.48%	1	0.01%
($200) to ($150)	4	0.06%	3	0.05%	14	0.64%	4	0.06%
($150) to ($100)	6	0.13%	5	0.10%	45	1.15%	17	0.25%
($100) to ($50)	17	0.32%	9	0.21%	91	2.19%	65	0.99%
($50) to $0	5,576	63.80%	5,994	68.63%	5,829	68.73%	6,034	69.87%
$0 to $50	3,061	98.65%	2,659	98.98%	2,525	97.56%	2,467	98.04%
$50 to $100	82	99.58%	64	99.71%	120	98.93%	126	99.47%
$100 to $150	17	99.77%	12	99.85%	39	99.37%	34	99.86%
$150 to $200	12	99.91%	10	99.97%	18	99.58%	7	99.94%
$200 to $250	5	99.97%	1	99.98%	9	99.68%	3	99.98%
$250 to $300	1	99.98%	2	100.00%	8	99.77%	1	99.99%
$300 to $350	2	100.00%	0	100.00%	3	99.81%	1	100.00%
$350 to $400	0	100.00%	0	100.00%	3	99.84%	0	100.00%
$400 to $450	0	100.00%	0	100.00%	2	99.86%	0	100.00%
$450 to $500	0	100.00%	0	100.00%	0	99.86%	0	100.00%
$500 to $750	0	100.00%	0	100.00%	7	99.94%	0	100.00%
$750 to $1,000	0	100.00%	0	100.00%	0	99.94%	0	100.00%
$1,000 to $1,250	0	100.00%	0	100.00%	1	99.95%	0	100.00%
>= $1,250	0	100.00%	0	100.00%	4	100.00%	0	100.00%

Figure 3-41 shows day-ahead and real-time LMP on an average hourly basis for 2015.

Figure 3-41 PJM system hourly average LMP: 2015



Scarcity

PJM's Energy Market experienced no shortage pricing events in 2015 compared to two days in 2014. Table 3-77 shows a summary of the number of days emergency alerts, warnings and actions were declared in PJM in 2014 and 2015.

Table 3-77 Summary of emergency events declared: 2014 and 2015

	Number of days events declared	
Event Type	2014	2015
Cold Weather Alert	25	26
Hot Weather Alert	7	19
Maximum Emergency Generation Alert	6	1
Primary Reserve Alert	2	0
Voltage Reduction Alert	2	0
Primary Reserve Warning	1	0
Voltage Reduction Warning	4	0
Pre Emergency Mandatory Load Management Reduction Action	0	2
Emergency Load Management Long Lead Time	6	2
Emergency Load Management Short Lead Time	6	2
Maximum Emergency Action	8	1
Emergency Energy Bids Requested	3	0
Voltage Reduction Action	1	0
Shortage Pricing	2	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 declared cold weather alerts on 26 days in 2015 compared to 25 days in 2014.[84] 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 ten degrees Fahrenheit.

PJM declared hot weather alerts on 19 days in 2015 compared to seven days in 2014.[85] The purpose of a hot weather alert is to prepare personnel and facilities for expected extreme hot and humid weather conditions, generally when temperatures are forecast to exceed 90 degrees Fahrenheit with high humidity.

PJM declared a maximum emergency generation alert on one day in 2015 compared to six days in 2014. The alert was issued for a subzone of the Dominion Zone for local transmission, and was cancelled less than an hour after it was declared. 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.[86] 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 2015 compared to two days in 2014. 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 2015, compared to two days in 2014. 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 2015, compared to one day in 2014. 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 non-critical plant load in 2015 compared to four days in 2014. The purpose of a voltage reduction warning and reduction of non-critical plant load is to warn members that available synchronized reserves are

84 See PJM. "Manual 13: Emergency Operations," Revision 59 (January 1, 2016), Section 3.3 Cold Weather Alert, p. 46.
85 See PJM. "Manual 13: Emergency Operations," Revision 59 (January 1, 2016), Section 3.4 Hot Weather Alert, p. 50.
86 See PJM. "Manual 13: Emergency Operations," Revision 59 (January 1, 2016), Section 2.3.1 Advance Notice Emergency Procedures: Alerts, p. 17.

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 declared emergency mandatory load management reductions on two days in 2015 compared to six days in 2014 in all or parts of the PJM service territory. 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 declared Pre-Emergency Mandatory Load Management Reduction Action on two days in 2015.

PJM declared maximum emergency generation action on one day in 2015 compared to eight days in 2014. 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 bids for emergency energy purchases in 2015 compared to three days in 2014.

PJM did not declare any voltage reduction actions in the first three months of 2015 compared to one day (January 6) in 2014. 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 non-synchronized reserve market clearing prices and locational marginal prices until the voltage reduction action has been terminated.

There were 21 synchronized reserve events in 2015 compared to 37 in 2014.[87] 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 3-78 provides a description of PJM declared emergency procedures.

87 See *2015 State of the Market Report for PJM*, Section 10: Ancillary Service Markets for details on the spinning events.

Table 3-78 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.
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.

Table 3-79 shows the dates when emergency alerts and warnings were declared and when emergency actions were implemented in 2015.

Table 3-79 PJM declared emergency alerts, warnings and actions, 2015

Dates	Cold Weather Alert	Hot Weather Alert	Maximum Emergency Generation Alert	Primary Reserve Alert	Voltage Reduction Alert	Primary Reserve Warning	Voltage Reduction Warning and Reduction of Non-Critical Plant Load	Pre-Emergency Mandatory Load Management Reduction	Maximum Emergency Generation Action	Emergency Mandatory Load Management Reduction	Voltage Reduction	Manual Load Dump Warning	Load Shed Directive
1/5/2015	ComEd												
1/6/2015	ComEd												
1/7/2015	PJM Western Region												
1/8/2015	PJM												
1/9/2015	PJM Western Region												
1/10/2015	PJM Western Region												
1/14/2015	PJM Western Region												
1/15/2015	PJM Western Region												
2/2/2015	PJM												
2/3/2015	PJM												
2/5/2015	ComEd,DLCO,ATSI												
2/6/2015	Mid-Atlantic												
2/13/2015	DLCO,AP,ATSI												
2/14/2015	PJM Western Region												
2/15/2015	Mid-Atlantic,PJM Western Region												
2/16/2015	PJM												
2/17/2015	Mid-Atlantic												
2/18/2015	PJM Western Region												
2/19/2015	PJM												
2/20/2015	PJM												
2/21/2015												AEP	
2/23/2015	PJM Western Region												
2/24/2015	PJM												
2/26/2015	DLCO,ATSI												
2/27/2015	PJM Western Region												
3/5/2015	ComEd												
3/6/2015	PJM Western Region												
4/21/2015								Penelec	Penelec	Penelec			
4/22/2015								Penelec		Penelec			
5/26/2015		Mid-Atlantic,PJM Southern Region											
5/27/2015		Mid-Atlantic,PJM Southern Region											AEP (Milton, WV)
6/11/2015		Mid-Atlantic,PJM Southern Region											
6/12/2015		Mid-Atlantic,PJM Southern Region											
6/13/2015		Mid-Atlantic,PJM Southern Region											
6/16/2015		PJM Southern Region											
6/21/2015		PJM Southern Region											
6/22/2015		Mid-Atlantic,PJM Southern Region											
6/23/2015		Mid-Atlantic,PJM Southern Region											AECO
7/20/2015		Mid-Atlantic, Dominion											
7/21/2015		Mid-Atlantic											
7/29/2015		Mid-Atlantic, Dominion	Dominion (Sub-zone)										
7/30/2015		Mid-Atlantic, Dominion											
8/17/2015		Mid-Atlantic											
9/1/2015		Mid-Atlantic											
9/2/2015		Mid-Atlantic											
9/3/2015		Mid-Atlantic											
9/8/2015		Mid-Atlantic											
9/9/2015		Mid-Atlantic											

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.[88] 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 non-synchronized reserve market clearing prices and the locational marginal price.

In 2015, there were no shortage pricing events triggered in PJM compared to two days in 2014.

NOPR on Shortage Pricing

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").[89] In particular, the price formation NOPR proposes (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.[90]

Currently in PJM, if the dispatch tools reflect shortage of reserves (primary or synchronized) for a time period shorter than a defined threshold (30 minutes in practice) 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. The rationale for having a minimum threshold time for a reserve shortage is to reflect the fact that the level of reserve measurement accuracy does not support a shorter time period. 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.[91]

If PJM were to move to a shortage pricing mechanism that is triggered by transient shortages, there needs to be accurate measurement of real time reserves that can support such a definition. That does not appear to be the case at present in PJM.

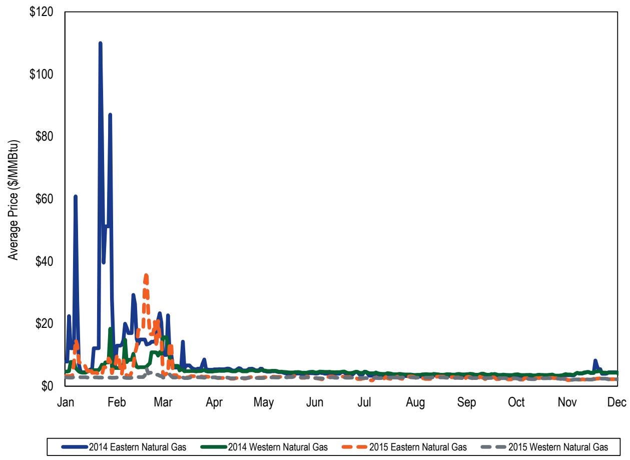
PJM Cold Weather Operations 2015

Natural gas supply and prices

As of January 1, 2015, gas fired generation was 30.7 percent (56,364.5 MW) of the total installed PJM capacity (183,726MW).[92] 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 3-42 shows the average daily price of delivered natural gas for eastern and western parts of PJM service territory in 2014 and 2015.[93]

88 See PJM OATT, 2.2 (d) General, (February 25, 2014), pp. 1815, 1819.
89 152 FERC ¶ 61,218 (September 17, 2015).
90 *Id* at P 5.
91 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)
92 *2015 State of the Market Report for PJM: January through September*, Section 5: Capacity Market, at Installed Capacity.
93 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.

Figure 3-42 Average daily delivered price for natural gas: 2014 and 2015 ($/MMBtu)



During the first three months of 2014 and 2015, a number of interstate gas pipelines that supply fuel for generators in the PJM service territory issued restriction notices limiting the availability of non-firm transportation services. These notices include warnings of operational flow orders (OFO) and actual OFOs. OFOs may 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 day, with penalties for deviating from the nominated quantities. Pipelines may also enforce strict balancing constraints which limit the ability of gas users (without no notice service or storage service) to deviate from the 24 hour ratable take and which 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.