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, including market size, concentration, pivotal suppliers, offer behavior, markup, and price. The MMU concludes that the PJM energy market results were competitive in the first nine months of 2021.

Table 3-1 The energy market results were competitive

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

- The aggregate market structure was evaluated as partially competitive because the aggregate market power test based on pivotal suppliers indicates that the aggregate day-ahead market structure was not competitive on every day. The hourly HHI (Herfindahl-Hirschman Index) results indicate that the PJM aggregate energy market in the first nine months of 2021 was, on average, unconcentrated by FERC HHI standards. Average HHI was 743 with a minimum of 530 and a maximum of 1114 in the first nine months of 2021. The peaking segment of supply was highly concentrated. The fact that the average HHI is in the unconcentrated range does not mean that the aggregate market was competitive in all hours. As demonstrated for the day-ahead market, it is possible to have pivotal suppliers in the aggregate market even when the HHI level is not in the highly concentrated range. It is possible to have an exercise of market power even when the HHI level is not in the highly concentrated range. The number of pivotal suppliers in the energy market is a more precise measure of structural market power than the HHI. The HHI is not a definitive measure of structural market power.
- The local market structure was evaluated as not competitive due to the highly concentrated ownership of supply in local markets created by transmission constraints and local reliability issues. 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 definition of cost-based offers and the application of market power mitigation to resources whose owners fail the TPS test that need to be addressed because unit owners can exercise market power even when they fail the TPS test.
- 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 both routinely and during periods of high demand represents economic withholding. The ownership of marginal units is concentrated. The markups of pivotal suppliers in the aggregate market and of many pivotal suppliers in local markets remain unmitigated due to the lack of aggregate market power mitigation and the flawed implementation of offer caps for resources that fail the TPS test. The markups of those participants affected LMP.
- 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 for some marginal units did affect prices.

- Market design was evaluated as effective because the analysis shows that the PJM energy market resulted in competitive market outcomes. In general, PJM's energy market design provides incentives for competitive behavior and results in competitive outcomes. In local markets, where market power is an issue, the market design identifies market power and causes the market to provide competitive market outcomes in most cases although issues with the implementation of market power mitigation and development of cost-based offers remain. The role of UTCs in the day-ahead energy market continues to cause concerns. Market design implementation issues, including inaccuracies in modeling of the transmission system and of generator capabilities as well as inefficiencies in real-time dispatch and price formation, undermine market efficiency in the energy market. PJM plans to resolve the problems with real time dispatch and pricing in November 2021. The implementation of fast start pricing on September 1, 2021, and the planned extended ORDC in October 2022 undermine market efficiency by setting inefficient prices that are inconsistent with the dispatch signals.
- 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 core functions is to identify actual or potential market design flaws.[1] The approach to market power mitigation in PJM has focused on market designs that promote competition (a structural basis for competitive outcomes) and on mitigating market power in instances where the market structure is not competitive and thus where market design alone cannot mitigate market power. FERC relies on effective market power mitigation when it approves market sellers to participate in the PJM market at market based rates.[2] In the PJM energy market, market power mitigation occurs primarily in the case of local market power. When a transmission constraint creates the potential for local market power, PJM applies a structural test to determine if the local market is competitive, applies a behavioral test to determine if generator offers exceed competitive levels and applies a market performance test to determine if such generator offers would affect the market price.[3] There are, however, identified issues with the application of market power mitigation to resources whose owners fail the TPS test that can result in the exercise of local market power even when market power mitigation rules are applied. These issues need to be addressed. FERC recognized these issues in its June 17, 2021 order.[4] Some units with market power have positive markups and some have inflexible parameters, which means that the cost-based offer was not used and that the process for offer capping units that fail the TPS test does not consistently result in competitive market outcomes in the presence of market power. There are issues related to the definition of gas costs includable in energy offers that need to be addressed. There are issues related to the level of maintenance expense includable in energy offers that need to be addressed. There are currently no market power mitigation rules in place that limit the ability to exercise market power when aggregate market conditions are tight and there are pivotal suppliers in the aggregate market. Aggregate market power needs to be addressed. Market design must reflect appropriate incentives for competitive behavior, the application of local market power mitigation needs to be fixed, the definition of a competitive offer needs to be fixed, and aggregate market power mitigation rules need to be developed. The importance of these issues is amplified by the rules permitting cost-based offers in excess of $1,000 per MWh.

Overview

Supply and Demand

Market Structure

- **Supply.** The average on-peak hourly day-ahead supply was 167,394 MW for summer 2020, and 164,847 MW for summer 2021. The average on-peak hourly offered real-time supply was 152,122 MW for summer 2020, and 152,828 MW for summer 2021. In the first nine months of 2021,

1 OATT Attachment M (PJM Market Monitoring Plan).

2 See *Refinements to Horizontal Market Power Analysis for Sellers in Certain Regional Transmission Organization and Independent System Operator Markets*, Order No. 861, 168 FERC ¶ 61,040 (July 18, 2019); *order on reh'g*, Order No. 861-A; 170 FERC ¶ 61,106 (2020).

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.

4 *PJM Interconnection, L.L.C.*, Order to Show Cause, (June 17, 2021) 175 FERC ¶ 61,231.

2,289.7 MW of new resources were added in the energy market, and 1,304.8 MW of resources were retired.

PJM average hourly real-time cleared generation in the first nine months of 2021 increased by 3.9 percent from the first nine months of 2020, from 92,226 MWh to 95,792 MWh.

PJM average hourly day-ahead supply including INCs and UTCs, decreased by 9.0 percent from the first nine months of 2020, from 115,205 MWh to 104,785 MWh.

- **Demand.** The PJM system real-time hourly peak load plus exports in the first nine months of 2021 was 151,680 MWh (145,561 MW of load plus 6,120 MW of gross exports) in the HE 1800 on August 24, 2021, which was 1.8 percent, 2,684 MWh higher than the PJM peak load plus exports in the first nine months of 2020, which was 148,996 MWh in the HE 1800 on July 20, 2020.

  PJM average hourly real-time load in the first nine months of 2021 increased by 4.2 percent from the first nine months of 2020, from 85,886 MWh to 89,515 MWh.

  PJM average hourly day-ahead demand including DECs and UTCs, decreased by 9.2 percent from the first nine months of 2020, from 109,850 MWh to 99,788 MWh.

Market Behavior

- **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 hourly average submitted increment offer MW decreased by 13.6 percent and cleared MW decreased by 5.2 percent in the first nine months of 2021 compared to the first nine months of 2020. The hourly average submitted decrement bid MW increased by 14.8 percent and cleared MW decreased by 0.7 percent in the first nine months of 2021 compared to the first nine months of 2020. The hourly average submitted up to congestion bid MW decreased by 61.3 percent and cleared MW decreased by 64.2 percent in the first nine months of 2021 compared to the first nine months of 2020.

Market Performance

- **Generation Fuel Mix.** In the first nine months of 2021, coal units provided 24.0 percent, nuclear units 32.1 percent and natural gas units 36.8 percent of total generation. Compared to the first nine months of 2020, the generation from coal units increased 30.9 percent, from nuclear units decreased 1.6 percent and from natural gas units decreased 6.4 percent.
- **Fuel Diversity.** The fuel diversity of energy generation for the first nine months of 2021, measured by the fuel diversity index for energy (FDI_e), increased 2.9 percent compared to the first nine months of 2020.
- **Marginal Resources.** In the PJM Real-Time Energy Market in the first nine months of 2021, coal units were 16.9 percent and natural gas units were 71.0 percent of marginal resources. In the first nine months of 2020, coal units were 17.3 percent and natural gas units were 73.9 percent of marginal resources.

  In the PJM Day-Ahead Energy Market in the first nine months of 2021, UTCs were 36.1 percent, INCs were 17.3 percent, DECs were 26.5 percent, and generation resources were 19.7 percent of marginal resources. In the first nine months of 2020, UTCs were 53.8 percent, INCs were 12.4 percent, DECs were 17.6 percent, and generation resources were 16.1 percent of marginal resources.
- **Prices.** PJM real-time, load-weighted average LMP in the first nine months of 2021 increased 68.1 percent from the first nine months of 2020, from $21.22 per MWh to $35.68 per MWh.

  PJM day-ahead, load-weighted average LMP in the first nine months of 2021 increased 69.5 percent from the first nine months of 2020, from $20.95 per MWh to $35.51 per MWh.
- **Fast Start Pricing.** In PJM Real-Time Energy Market, real-time average PLMP is $46.79 per MWh since September 1, 2021, which is 3.5 percent,

$1.59 per MWh, higher than the real-time average DLMP of $45.21 per MWh.

- **Components of LMP.** In the PJM Real-Time Energy Market in the first nine months of 2021, 12.4 percent of the load-weighted LMP was the result of coal costs, 53.9 percent was the result of gas costs and 3.5 percent was the result of the cost of emission allowances. In the first nine months of 2021, 8.6 percent of load-weighted LMP was the result of the transmission constraint violation penalty factor due to an increased frequency of transmission constraint violations, especially on the 500 kV system. PJM implemented Fast Start Pricing on September 1, 2021, which explicitly allowed commitment costs to affect LMPs. In the first month of the fast start pricing in PJM, 2.8 percent of the real-time, load-weighted average LMP was the result of commitment costs.

  In the PJM Day-Ahead Energy Market, in the first nine months of 2021, 26.1 percent of the load-weighted LMP was the result of gas costs, 29.5 percent was the result of DEC bids, 12.6 percent was the result of coal costs, 13.1 percent was the result of INC offers, 5.1 percent was the result of positive markup, and 2.6 percent was the result of UTCs.

- **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 average day-ahead and real-time prices was $0.15 per MWh in the first nine months of 2021, and $0.23 per MWh in the first nine months of 2020. 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 19 intervals with five minute shortage pricing in the first nine months of 2021. There were no emergency actions that resulted in Performance Assessment Intervals in the first nine months of 2021.
- There were 2,735 five minute intervals, or 3.5 percent of all five minute intervals in the first nine months of 2021 for which at least one RT SCED solution showed a shortage of reserves, and 737 five minute intervals, or 0.9 percent of all five minute intervals in the first nine months of 2021 for which more than one RT SCED solution showed a shortage of reserves. PJM triggered shortage pricing for 19 five minute intervals.

Competitive Assessment

Market Structure

- **Aggregate Pivotal Suppliers.** The PJM energy market, at times, requires generation from pivotal suppliers to meet load, resulting in aggregate market power even when the HHI level indicates that the aggregate market is unconcentrated.
- **Local Market Power.** In the first nine months of 2021, 12 control zones experienced congestion resulting from one or more constraints binding for 75 or more hours. For four out of the top 10 congested facilities (by real-time binding hours) in the first nine months of 2021, the average number of suppliers providing constraint relief was three or less. There is a high level of concentration within the local markets for providing relief to the most congested facilities in the PJM Real-Time Energy Market. The local market structure is not competitive.

Market Behavior

- **Offer Capping for Local Market Power.** PJM offer caps units when the local market structure is noncompetitive. Offer capping is an effective means of addressing local market power when the rules are designed and implemented properly. Offer capping levels have historically been low in PJM. In the day-ahead energy market, for units committed to provide energy for local constraint relief, offer-capped unit hours decreased from 1.6 percent in the first nine months of 2020 to 1.4 percent in the first nine months of 2021. In the real-time energy market, for units committed to provide energy for local constraint relief, offer-capped unit hours increased from 1.0 percent in the first nine months of 2020 to 1.3 percent in the first nine months of 2021. While overall offer capping levels have been low, there are a significant number of units with persistent structural local market power that would have a significant impact on prices in the absence of local market power mitigation.

The analysis of the application of the TPS test to local markets demonstrates that it is working 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, including for reactive support. In the day-ahead energy market, for units committed for reliability reasons, offer-capped unit hours increased from 0.00 percent in the first nine months of 2020 to 0.02 percent in the first nine months of 2021. In the real-time energy market, for units committed for reliability reasons, offer-capped unit hours increased from 0.00 percent in the first nine months of 2020 to 0.02 percent in the first nine months of 2021. The low offer cap percentages do not mean that units manually committed for reliability reasons do not have market power. All units manually committed for reliability have market power and all are treated as if they had market power. These units are not capped to their cost-based offers because they tend to offer with a negative markup in their price-based offers, particularly at the economic minimum level, which means that PJM's offer capping process results in the use of the price-based offer for commitment even if it has less flexible operating parameters.
- **Parameter Mitigation.** In the first nine months of 2021, 30.4 percent of unit hours for units that failed the TPS test in the day-ahead market were committed on price-based schedules that were less flexible than their cost-based schedules. In the first nine months of 2021, on days when hot weather and cold weather alerts were declared, 32.6 percent of unit hours in the day-ahead energy market were committed on price-based schedules that were less flexible than their price PLS schedules.
- **Frequently Mitigated Units (FMU) and Associated Units (AU).** In 2020, five units qualified for an FMU adder in at least one month. In the first nine months of 2021, one unit qualified for an FMU adder in January.
- **Markup Index.** The markup index is a summary measure of participant offer behavior for individual marginal units. While the average markup index in the real-time market was -0.20 in the first nine months of 2021, some marginal units did have substantial markups. The highest markup for any marginal unit in the real-time market in the first nine months of 2021 was more than $450 per MWh when using unadjusted cost-based offers.

  While the average markup index in the day-ahead market was 0.04 in the first nine months of 2021, some marginal units did have substantial markups. The highest markup for any marginal unit in the day-ahead market in the first nine months of 2021 was more than $140 per MWh when using unadjusted cost-based offers.
- **Markup.** The markup frequency distributions show that a significant proportion of units make price-based offers less than the cost-based offers permitted under the PJM market rules. This behavior means that competitive price-based offers reveal actual unit marginal costs and that PJM market rules permit the inclusion of costs in cost-based offers that are not short run marginal costs.

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

Market Performance

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

  In the PJM Real-Time Energy Market in the first nine months of 2021, the unadjusted markup component of LMP was $1.25 per MWh or 3.5 percent of the PJM load-weighted, average LMP. August had the highest peak markup component, $6.68 per MWh, or 11.8 percent of the real-time, peak hour load-weighted, average LMP for August.

In the PJM Day-Ahead Energy Market, INCs, DECs and UTCs have zero markups. In the first nine months of 2021, the unadjusted positive markup component of LMP was $1.82 per MWh or 5.1 percent of the PJM day-ahead load-weighted, average LMP and the unadjusted negative markup component of LMP was -$0.98 or -2.8 percent of the PJM day-ahead load-weighted, average LMP. September had the highest unadjusted peak markup component, $3.44 per MWh.

Participant behavior was evaluated as competitive because the analysis of markup shows that marginal units generally make offers at, or close to, their marginal costs in both the day-ahead and real-time energy markets, although the behavior of some participants represents economic withholding.

- **Markup and Local Market Power.** Comparison of the markup behavior of marginal units with TPS test results shows that for 6.4 percent of all real-time marginal unit intervals in the first nine months of 2021, the marginal unit had both local market power as determined by the TPS test and a positive markup. The fact that units with market power had a positive markup means that the cost-based offer was not used, that a higher price-based offer was used, and that the process for offer capping units that fail the TPS test does not consistently result in competitive market outcomes in the presence of market power.
- **Markup and Aggregate Market Power.** In the first nine months of 2021, pivotal suppliers in the aggregate market set prices with high markups for some real-time market intervals.

Recommendations

Market Power

- The MMU recommends that the market rules explicitly require that offers in the energy market be competitive, where competitive is defined to be the short run marginal cost of the units. The short run marginal cost should reflect opportunity cost when and where appropriate. The MMU recommends that the level of incremental costs includable in cost-based offers not exceed the short run marginal cost of the unit. (Priority: Medium. First reported 2009. Status: Not adopted.)

Fuel Cost Policies

- The MMU recommends that PJM require that all fuel cost policies be algorithmic, verifiable, and systematic, and accurately reflect short run marginal costs. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that the tariff be changed to allow units to have fuel cost policies that do not include fuel procurement practices, including fuel contracts. Fuel procurement practices, including fuel contracts, may be used as the basis for fuel cost policies but should not be required. (Priority: Low. First reported 2018. Status: Adopted 2020.)
- The MMU recommends that PJM change the fuel cost policy requirement to apply only to units that will be offered with non-zero cost-based offers. The PJM market rules should require that the cost-based offers of units without an approved fuel cost policy be set to zero. (Priority: Low. First reported 2018. Status: Adopted 2020.)
- The MMU recommends that the temporary cost method be removed and that all units that submit nonzero cost-based offers be required to have an approved fuel cost policy. (Priority: Low. First reported 2020. Status: Not adopted.)
- The MMU recommends that the penalty exemption provision be removed and that all units that submit nonzero cost-based offers be required to follow their approved fuel cost policy. (Priority: Medium. First reported 2020. Status: Not adopted.)

Cost-Based Offers

- The MMU recommends that Manual 15 (Cost Development Guidelines) be replaced with a straightforward description of the components of cost-based offers based on short run marginal costs and the correct calculation of cost-based offers. (Priority: Medium. First reported 2016. Status: Not adopted.)

- The MMU recommends removal of all use of FERC System of Accounts in the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends the removal of all use of cyclic starting and peaking factors from the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends the removal of all labor costs from the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends the removal of all maintenance costs from the Cost Development Guidelines. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that market participants be required to document the amount and cost of consumables used when operating in order to verify that the total operating cost is consistent with the total quantity used and the unit characteristics. (Priority: Medium. First reported 2020. Status: Not adopted.)
- The MMU recommends, given that maintenance costs are currently allowed in cost-based offers, that market participants be permitted to include only variable maintenance costs, linked to verifiable operational events and that can be supported by clear and unambiguous documentation of the operational data (e.g. run hours, MWh, MMBtu) that support the maintenance cycle of the equipment being serviced/replaced. (Priority: Medium. First reported 2020. Status: Not adopted.)
- The MMU recommends explicitly accounting for soak costs and changing the definition of the start heat input for combined cycles to include only the amount of fuel used from first fire to the first breaker close in the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends the removal of nuclear fuel and nonfuel operations and maintenance costs that are not short run marginal costs from the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends revising the pumped hydro fuel cost calculation to include day-ahead and real-time power purchases. (Priority: Low. First reported 2016. Status: Not adopted.)
- The MMU recommends revisions to the calculation of energy market opportunity costs to incorporate all time based offer parameters and all limitations that impact the opportunity cost of generating unit output. (Priority: Medium. First reported 2016. Status: Adopted 2020.)
- The MMU recommends removing the catastrophic designation for force majeure fuel supply limitations in Schedule 2. (Priority: Medium. First reported 2016. Status: Not adopted.)

Market Power: TPS Test and Offer Capping

- The MMU recommends that the rules governing the application of the TPS test be clarified and documented. The TPS test application in the day-ahead energy market is not documented. (Priority: High. First reported 2015. Status: Partially adopted.)
- The MMU recommends, in order to ensure effective market power mitigation and to ensure that capacity resources meet their obligations to be flexible, that capacity resources be required to use flexible parameters in all offers at all times. (Priority: High. New recommendation. Status: Not adopted.)
- The MMU recommends, if the preferred recommendation is not implemented, that in order to ensure effective market power mitigation, PJM always enforce parameter limited values when the TPS test is failed and during high load conditions such as cold and hot weather alerts and emergency conditions. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM require every market participant to make available at least one cost schedule based on the same hourly fuel

type(s) and parameters at least as flexible as their offered price schedule. (Priority: Medium. First reported 2015. Status: Not adopted.)

- The MMU recommends, in order to ensure effective market power mitigation when the TPS test is failed, that markup be consistently positive or negative across the full MWh range of price and cost-based offers. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends, in order to ensure effective market power mitigation when the TPS test is failed, that offer capping be applied to units that fail the TPS test in the real-time market that were not offer capped at the time of commitment in the day-ahead market or at a prior time in the real-time market. (Priority: High. First reported 2020. Status: Not adopted.)
- The MMU recommends that PJM retain the $1,000 per MWh offer cap in the PJM energy market except when cost-based offers exceed $1,000 per MWh, and retain other existing rules that limit incentives to exercise market power. (Priority: High. First reported 1999. Status: Partially adopted, 1999, 2017.)
- The MMU recommends the elimination of FMU and AU adders. FMU and AU adders no longer serve the purpose for which they were created and interfere with the efficient operation of PJM markets. (Priority: Medium. First reported 2012. Status: Partially adopted, 2014.)

Offer Behavior

- The MMU recommends that resources not be allowed to violate the ICAP must offer requirement. The MMU recommends that PJM enforce the ICAP must offer requirement by assigning a forced outage to any unit that is derated in the energy market below its committed ICAP without an outage that reflects the derate. (Priority: Medium. First reported 2020. Status: Not adopted.)
- The MMU recommends that storage and intermittent resources be subject to an enforceable ICAP must offer rule that reflects the limitations of these resources. (Priority: Medium. First reported 2020. Status: Not adopted.)
- The MMU recommends that capacity resources not be allowed to offer any portion of their capacity market obligation as maximum emergency energy. (Priority: Medium. First reported 2012. Status: Not adopted.)

Capacity Performance Resources

- The MMU recommends that capacity performance resources be held to the OEM operating parameters of the capacity market CONE reference resource for performance assessment and energy uplift payments and that this standard be applied to all technologies on a uniform basis. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that the parameters which determine nonperformance charges and the amounts of uplift payments should reflect the flexibility goals of the capacity performance construct. The operational parameters used by generation owners to indicate to PJM operators what a unit is capable of during the operating day should not determine capacity performance assessment or uplift payments. (Priority: Medium. First reported 2015. Status: Partially adopted.)
- The MMU recommends that PJM not include the balancing ratios calculated for localized Performance Assessment Intervals (PAIs) in the capacity market default offer cap, and only include those events that trigger emergencies at a defined zonal or higher level. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM clearly define the business rules that apply to the unit specific parameter adjustment process, including PJM's implementation of the tariff rules in the PJM manuals to ensure market sellers know the requirements for their resources. (Priority: Low. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM update the tariff to clarify that all generation resources are subject to unit specific parameter limits on their cost-based offers using the same standard and process as capacity performance capacity resources. (Priority: Medium. First reported 2018. Status: Not adopted.)

- The MMU recommends that resources not be paid the daily capacity payment when unable to operate to their unit specific parameter limits. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM not approve temporary exceptions that are based on pipeline tariff terms that are not routinely enforced, and based on inferior transportation service procured by the generator. (Priority: Medium. First reported 2019. Status: Not adopted.)

Accurate System Modeling

- The MMU recommends that PJM approve one RT SCED case for each five minute interval to dispatch resources during that interval using a five minute ramp time, and that PJM calculate prices using LPC for that five minute interval using the same approved RT SCED case. (Priority: High. First reported 2019. Status: Not adopted.)
- The MMU recommends that PJM explicitly state its policy on the use of transmission penalty factors including: the level of the penalty factors; the triggers for the use of the penalty factors; the appropriate line ratings to trigger the use of penalty factors; the allowed duration of the violation; the use of constraint relaxation logic; and when the transmission penalty factors will be used to set the shadow price. (Priority: Medium. First reported 2015. Status: Partially adopted 2020.)
- The MMU recommends that PJM routinely review all transmission facility ratings and any changes to those ratings to ensure that the normal, emergency and load dump ratings used in modeling the transmission system are accurate and reflect standard ratings practice. (Priority: Low. First reported 2013. Status: Partially adopted.)
- The MMU recommends that PJM not use closed loop interface or surrogate constraints to artificially override nodal prices based on fundamental LMP logic in order to: accommodate rather than resolve the inadequacies of the demand side resource capacity product; address the inability of the power flow model to incorporate the need for reactive power; accommodate rather than resolve the flaws in PJM's approach to scarcity pricing; or for any other reason. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM not use CT price setting logic to modify transmission line limits to artificially override the nodal prices that are based on fundamental LMP logic in order to reduce uplift. (Priority: Medium. First reported 2015. Status: Adopted 2021.)
- The MMU recommends that if PJM believes it appropriate to implement CT price setting logic, PJM first initiate a stakeholder process to determine whether such modification is appropriate. PJM should file any proposed changes with FERC to ensure review. Any such changes should be incorporated in the PJM tariff. (Priority: Medium. First reported 2016. Status: Adopted 2021.)
- 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 PJM include in the tariff or appropriate manual an explanation of the initial creation of hubs, the process for modifying hub definitions and a description of how hub definitions have changed.[5] [6] (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that all buses with a net withdrawal be treated as load for purposes of calculating load and load-weighted LMP, even if the MW are settled to the generator. 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, even if the injection MW are settled to the load serving entity. (Priority: Low. First reported 2013. Status: Not adopted.)

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

6 There is currently no PJM documentation in the tariff or manuals explaining how hubs are created and how their definitions are changed. The general definition of a hub can be found in the PJM.com Glossary <http://www.pjm.com/Glossary.aspx>.

- 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 document how LMPs are calculated when demand response is marginal. (Priority: Low. First reported 2014. Status: Not adopted.)
- The MMU recommends that PJM not allow nuclear generators which do not respond to prices or which only respond to manual instructions from the operator to set the LMPs in the real-time market. (Priority: Low. First reported 2016. Status: Not adopted.)
- The MMU recommends that PJM increase the coordination of outage and operational restrictions data submitted by market participants via eDART/eGADs and offer data submitted via Markets Gateway. (Priority: Low. First reported 2017. Status: Not adopted.)
- The MMU recommends that PJM model generators' operating transitions, including soak time for units with a steam turbine, configuration transitions for combined cycles, and peak operating modes. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that PJM clarify, modify and document its process for dispatching reserves and energy when SCED indicates that supply is less than total demand including forecasted load and reserve requirements. The modifications should define: a SCED process to economically convert reserves to energy; a process for the recall of energy from capacity resources; and the minimum level of synchronized reserves that would trigger load shedding. (Priority: Medium. First reported 2020. Status: Not adopted.)
- The MMU recommends that PJM stop capping the system marginal price in RT SCED and instead limit the sum of violated reserve constraint shadow prices used in LPC to $1,700 per MWh. (Priority: Medium. First reported Q1, 2021. Status: Not adopted.)
- The MMU recommends, if PJM implements extended downward sloping ORDCs, that PJM calculate the probability of reserves falling below the minimum reserve requirement (MRR) based on ten minute rather than 30 minute forecast error, and on forced outages in the ten minute rather than the 30 minute look ahead window to model the uncertainty in the inputs to RT SCED. (Priority: Medium. First reported Q2, 2021. Status: Not adopted.)

Transparency

- The MMU recommends that PJM market rules require the fuel type be identified for every price and cost schedule and PJM market rules remove nonspecific fuel types such as other or co-fire other from the list of fuel types available for market participants to identify the fuel type associated with their price and cost schedules. (Priority: Medium. First reported 2015. Status: Adopted 2019.)
- The MMU recommends that PJM allow generators to report fuel type on an hourly basis in their offer schedules and to designate schedule availability on an hourly basis. (Priority: Medium. First reported 2015. Status: Partially adopted.)
- The MMU recommends that PJM define clear criteria for operator approval of RT SCED cases, including shortage cases, that are used to send dispatch signals to resources, and for pricing, to minimize discretion. (Priority: High. First reported 2018. Status: Partially adopted.)

Virtual Bids and Offers

- The MMU recommends eliminating up to congestion (UTC) bidding at pricing nodes that aggregate only small sections of transmission zones with few physical assets. (Priority: Medium. First reported 2020. Status: Not adopted.)
- The MMU recommends eliminating INC, DEC, and UTC bidding at pricing nodes that allow market participants to profit from modeling issues. (Priority: Medium. First reported 2020. Status: Not adopted.)

Conclusion

The MMU analyzed key elements of PJM energy market structure, participant conduct and market performance in the first nine months of 2021, including aggregate supply and demand, concentration ratios, aggregate pivotal supplier results, local three pivotal supplier test results, offer capping, markup, marginal units, participation in demand response programs, virtual bids and offers, loads and prices.

PJM average hourly real-time load in the first nine months of 2021 increased by 4.2 percent from the first nine months of 2020, from 85,886 MWh to 89,515 MWh. The relationship between supply and demand, regardless of the specific market, along with market concentration and the extent of pivotal suppliers, is referred to as the supply-demand fundamentals or economic fundamentals or market structure. The market structure of the PJM aggregate energy market is partially competitive because aggregate market power does exist for a significant number of hours. The HHI is not a definitive measure of structural market power. The number of pivotal suppliers in the energy market is a more precise measure of structural market power than the HHI. It is possible to have pivotal suppliers in the aggregate market even when the HHI level is not in the highly concentrated range. Even a low HHI may be consistent with the exercise of market power with a low price elasticity of demand. The current market power mitigation rules for the PJM energy market rely on the assumption that the ownership structure of the aggregate market ensures competitive outcomes. This assumption requires that the total demand for energy can be met without the supply from any individual supplier or without the supply from a small group of suppliers. This assumption is not correct. There are pivotal suppliers in the aggregate energy market at times. High markups for some units demonstrate the potential to exercise market power both routinely and during high demand conditions. The existing market power mitigation measures do not address aggregate market power. The MMU is developing an aggregate market power test and will propose market power mitigation rules to address aggregate market power.

The three pivotal supplier test is applied by PJM on an ongoing basis for local energy markets in order to determine whether offer capping is required for transmission constraints.[7] However, there are some issues with the application of market power mitigation in the day-ahead energy market and the real-time energy market when market sellers fail the TPS test. The Commission recognized some of these issues in its order issued on June 17, 2021.[8] PJM continues to ignore the evidence cited by the Commission and denies the prevalence of these issues, instead of ensuring that market power mitigation works as intended and results in efficient market outcomes.[9] Many of these issues can be resolved by simple rule changes. The MMU proposed these rule changes in its response submitted on October 15, 2021 and continues to recommends them.[10]

The enforcement of market power mitigation rules is undermined if the definition of a competitive offer is not correct. A competitive offer is equal to short run marginal costs. The significance of competition metrics like markup is also undermined if the definition of a competitive offer is not correct. The definition of a competitive offer, under the PJM Market Rules, is not currently correct. The definition, that all costs that are related to electric production are short run marginal costs, is not clear or correct. All costs and investments for power generation are related to electric production. Under this definition, some unit owners include costs that are not short run marginal costs in offers, especially maintenance costs. This issue can be resolved by simple rule changes to incorporate a clear and accurate definition of short run marginal costs.

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. In a competitive market, prices are directly related to the marginal cost to serve load at a given time. The pattern of prices within days and across months and years illustrates how prices are directly related to supply and demand conditions and thus also illustrates the potential significance of the impact of the price elasticity of demand on prices. Energy market results in the first nine months of 2021 generally reflected supply-demand fundamentals, although the behavior of some participants both routinely and during high

7 The MMU reviews PJM's application of the TPS test and brings issues to the attention of PJM.
8 See 175 FERC ¶ 61,231 (June 17, 2021).
9 *See* PJM. "Answer of PJM Interconnection L.L.C.," Docket No. EL21-78 (September 15, 2021).
10 *See* "Comments of the Independent Market Monitor for PJM," Docket No. EL21-78 (October 15, 2021).

demand periods represents economic withholding. Economic withholding occurs when generator offers are greater than competitive levels. 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, staff their units, and operate rather than economically withhold or physically withhold.

Prices in PJM are the result of input prices, consistent with a competitive market. Low natural gas prices were a primary cause of low PJM energy market prices from 2017 to 2020. Higher natural gas prices are a primary cause of higher prices in 2021. There is no evidence to support significant changes to the calculation of LMP, such as fast start pricing or the extended ORDC. Fast start pricing, implemented on September 1, 2021, has disconnected pricing from dispatch instructions and created a greater reliance on uplift rather than price as an incentive to follow PJM's instructions. The extended ORDCs will create shortage pricing when no reserve shortages exist. These changes are unnecessary and distort, rather than improve, price formation. PJM is appropriately and directly addressing price formation with the changes that went into effect on November 1, 2021, to resolve the timing mismatch between pricing (LPC) and dispatch instructions (RT SCED). Other potential areas for price formation improvement include shortage pricing, operator actions and the design of reserve markets.

The PJM defined inputs to the dispatch tools, particularly the RT SCED, have substantial effects on energy market outcomes. Transmission line ratings, transmission penalty factors, load forecast bias, hydro resource schedules, and unit ramp rate adjustments change the dispatch of the system, affect prices, and can create significant price increases, particularly through transmission line limit violations. The automated adjustment of ramp rates by PJM, called Degree of Generator Performance (DGP), modified the values offered by generators and limits the MW available to the RT SCED through the first nine months of 2021.[11] Rather than sending dispatch signals consistent with resource offers and holding resources accountable when they fail to follow them, DGP accommodates resources that do not follow dispatch. PJM operator interventions to reduce line ratings unnecessarily trigger transmission constraint penalty factors and significantly increase prices. PJM should evaluate its interventions in the market, consider whether the interventions are appropriate, and provide greater transparency to enhance market efficiency.

The objective of efficient short run price signals is to minimize system production costs, not to minimize uplift. Repricing the market to reflect commitment costs prioritizes minimizing uplift over minimizing production costs. The tradeoff exists because when commitment costs are included in prices, the price signal no longer equals the short run marginal cost and therefore no longer provides the correct signal for efficient behavior for market participants making decisions on the margin, whether resources, load, interchange transactions, or virtual traders. This tradeoff is created by fast start pricing and would be created in a much more extensive form by PJM's pending extended ORDC pricing changes.[12]

Units that start in one hour are not actually fast start units, and their commitment costs are not marginal in a five minute market. The differences between the actual LMP and the fast start LMP will distort the incentive for market participants to behave competitively and to follow PJM's dispatch instructions. PJM is paying new forms of uplift in an attempt to counter the distorted incentives. The magnitude of the new payments and their effects on behavior are not well understood.

PJM's arguments for changing energy market price formation asserted that fast start pricing and the extended ORDC would price flexibility in the market, but instead they will benefit inflexible units. The fast start pricing and extended ORDC solutions would undercut LMP logic rather than directly addressing the underlying issues. The solution is not to accept that the inflexible CT should be paid or set price based on its commitment costs rather than its short run marginal costs. The question of why units make inflexible offers should be addressed directly. Are units inflexible because they are old and inefficient, because owners have not invested in increased flexibility or because they serve as a mechanism for the exercise of market power? The question of

11 DGP in the calculation of energy dispatch was removed as of November 1, 2021.

12 See 173 FERC ¶ 61,244 (2020).

why the unit was built, whether it was built under cost of service regulation and whether it is efficient to retain the unit should be answered directly. The question of how to provide market incentives for investment in flexible units, for investment in increased flexibility of existing units, and for operating at the full extent of existing flexibility should be addressed directly. The question of whether inflexible units should be paid uplift at all should be addressed directly. Marginal cost pricing without paying excess uplift to inflexible units would create incentives for market participants to provide flexible solutions including replacing inefficient units with flexible, efficient units.

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 and ensure no scarcity pricing when such pricing is not consistent with market conditions. Scarcity pricing can serve two functions in wholesale power markets: revenue adequacy and price signals. Scarcity pricing for revenue adequacy, as in PJM's ORDC proposal, 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, that scarcity pricing only occurs when scarcity exists, 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. Administrative scarcity pricing that establishes scarcity pricing in about 85 percent of hours, as PJM's ORDC proposal would, is not scarcity pricing but simply a revenue enhancement mechanism, which could have unintended consequences in an emergency, as was the case in ERCOT in February 2021. PJM's pending ORDC changes are not consistent with efficient market design and are just a revenue enhancement mechanism.

The PJM Capacity Market is explicitly designed to provide revenue adequacy and the resultant reliability. However, the explicit balancing mechanism that included net revenues directly in unit offers in the prior capacity market design is not present in the Capacity Performance design. The nature of a direct and explicit energy pricing net revenue true up mechanism in the capacity market should be addressed if energy revenues are expected to increase as a result of scarcity events, as a result of increased demand for reserves, or as a result of PJM's inappropriate proposals related to fast start pricing and the inclusion of maintenance expenses as short run marginal costs. The true up mechanism must address both cleared auctions and subsequent auctions. There are also significant issues with PJM's scarcity pricing rules, including the absence of a clear trigger based on measured reserve levels (the current triggers are based on estimated reserves) and the lack of adequate locational scarcity pricing options.

The overall energy market results support the conclusion that energy prices in PJM are set, generally, by marginal units operating at, or close to, their marginal costs, although this was not always the case in the first nine months of 2021 or prior years. In the first nine months of 2021, marginal units were predominantly combined cycle gas generators. The frequency of combined cycle gas units as the marginal unit type has risen rapidly, from 29.2 percent in the first nine months of 2016 to 60.9 percent in the first nine months of 2021. Overdue improvements in generator modeling in the energy market would allow PJM to more efficiently commit and dispatch combined cycle plants and to fully reflect the flexibility of these units. New combined cycle units have placed competitive pressure on less efficient generators, and the market has reliably served load with less congestion, less uplift, and less markup as a result. This is evidence of generally competitive behavior and competitive market outcomes, although the behavior of some participants represents economic withholding. Given the structure of the energy market which can permit the exercise of aggregate and local market power, the change in some participants' behavior is a source of concern in the energy market and provides a reason to use correctly defined short run marginal cost as the sole basis for cost-based offers and a reason for implementing an aggregate market power test and correcting the offer capping process for resources with local market power. The MMU concludes that the PJM energy market results were competitive in the first nine months of 2021.

Supply and Demand

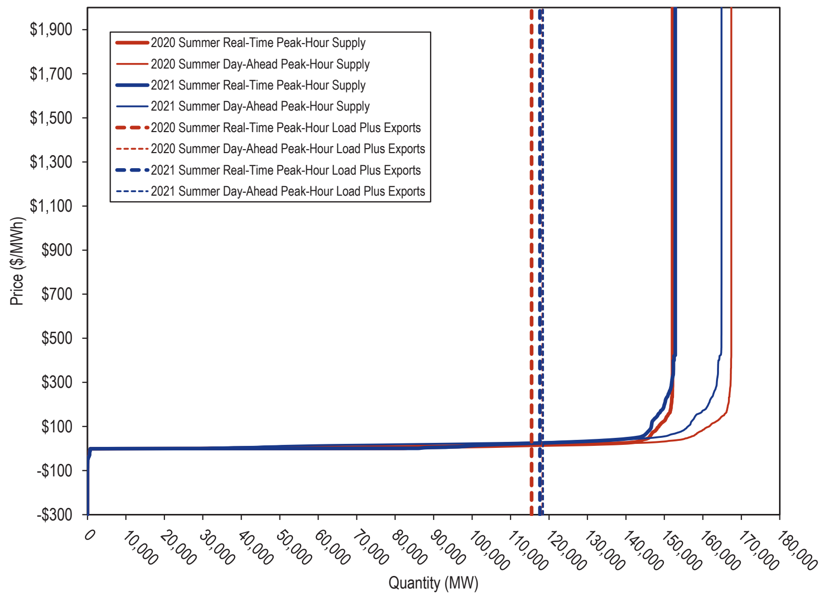
Market Structure

Supply

Supply includes physical generation, imports and virtual transactions.

In the first nine months of 2021, 2,289.7 MW of new resources were added in the energy market, and 1,304.8 MW of resources were retired. Figure 3-1 shows the average real-time and day-ahead supply curves in summer 2020 and 2021.[13] [14] The real-time supply curve includes average on peak hourly offers. The real-time supply curve includes available MW from units that are online or have a notification plus start time that is no more than one hour. The day-ahead supply curve shows the average of all available peak hourly offers.

Figure 3-1 Hourly real-time and aggregate day-ahead supply curve comparison: Summer of 2020 and 2021



13 Real-time supply includes real-time generation offers and import MWh.
14 The summer supply curve period is from June 1 to August 31

Figure 3-2 shows the typical dispatch range.

Figure 3-2 Typical dispatch range of supply curves

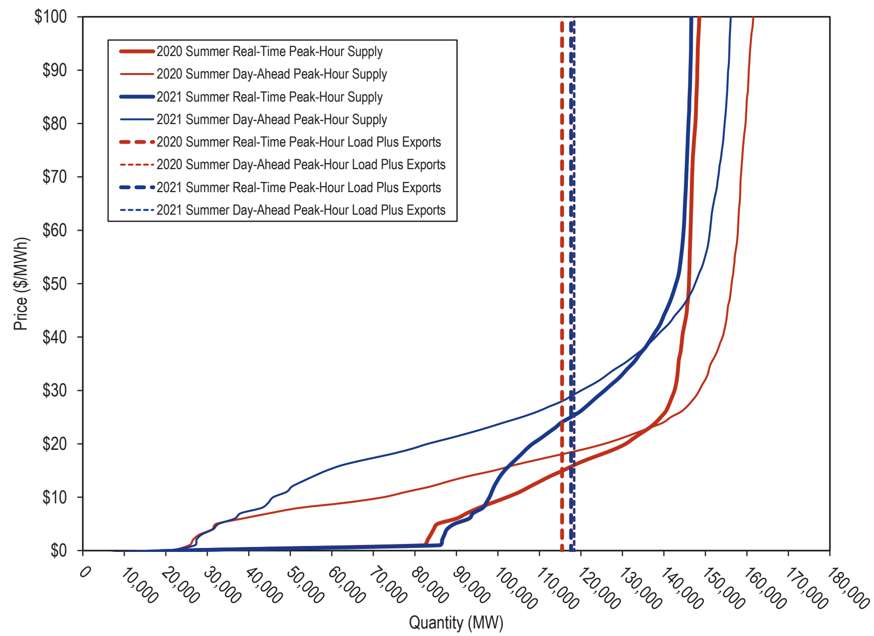


Table 3-2 shows the price elasticity of the real-time supply curve for the on peak hours in the summer of 2019 to 2021 by load level.

The price elasticity of the supply curve measures the responsiveness of the quantity supplied (GW) to a change in price:

$$\text{Elasticity of Supply} = \frac{\text{Percent change in quantity supplied}}{\text{Percent change in price}}$$

The supply curve is elastic when elasticity is greater than 1.0. The supply curve is more sensitive to changes in price the higher the elasticity. Although the aggregate supply curve may appear flat as a result of the wide range in prices and quantities, the calculated elasticity is low throughout. The shape of the supply curve below 115 GWh changed in summer 2021 compared to previous years primarily as a result of higher fuel prices.

Table 3-2 Price elasticity of the supply curve

Elasticity of Summer Supply Curve			
GW	2019	2020	2021
Min - 95	0.020	0.026	0.017
95 - 115	0.302	0.256	0.104
115 - 135	0.415	0.353	0.286
135 - Max	0.003	0.003	0.005

Real-Time Supply

PJM average hourly real-time cleared generation in the first nine months of 2021 increased by 3.9 percent from the first nine months of 2020, from 92,226 MWh to 95,792 MWh.[15]

PJM average hourly real-time cleared supply including imports in the first nine months of 2021 increased by 3.8 percent from the first nine months of 2020, from 92,983 MWh to 96,519 MWh.

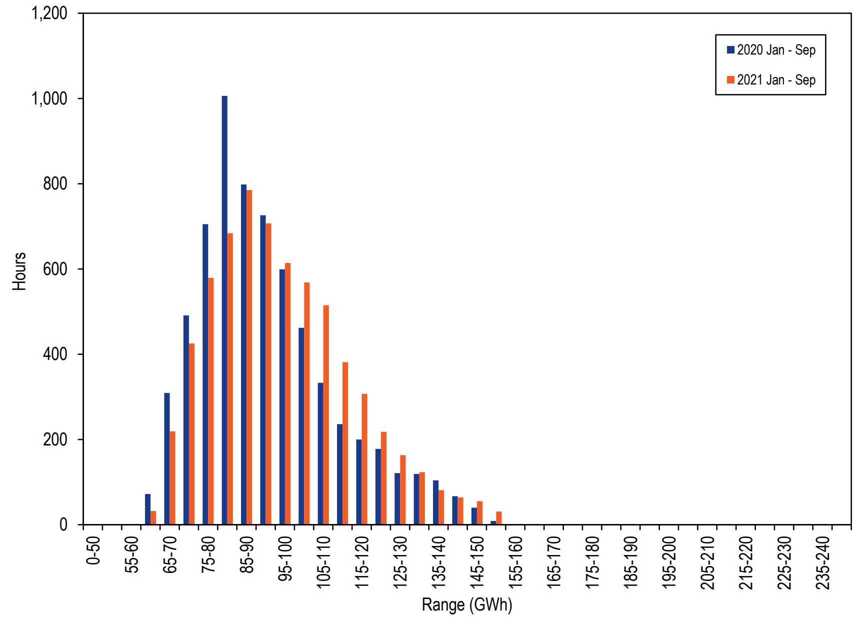
In the PJM Real-Time Energy Market, there are three types of supply offers:

- **Self Scheduled Generation Offer.** Offer to supply a fixed block of MW, as a price taker, from a unit that may also have a dispatchable component above the fixed MW.
- **Dispatchable Generation Offer.** Offer to supply a schedule of MW 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 Frequency

Figure 3-3 shows the hourly distribution of PJM real-time generation plus imports for the first nine months of 2020 and 2021.

Figure 3-3 Distribution of real-time generation plus imports: January through September, 2020 and 2021[16]



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

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

PJM Real-Time, Average Supply

Table 3-3 shows real-time hourly supply for the first nine months of each year from 2001 through 2021.

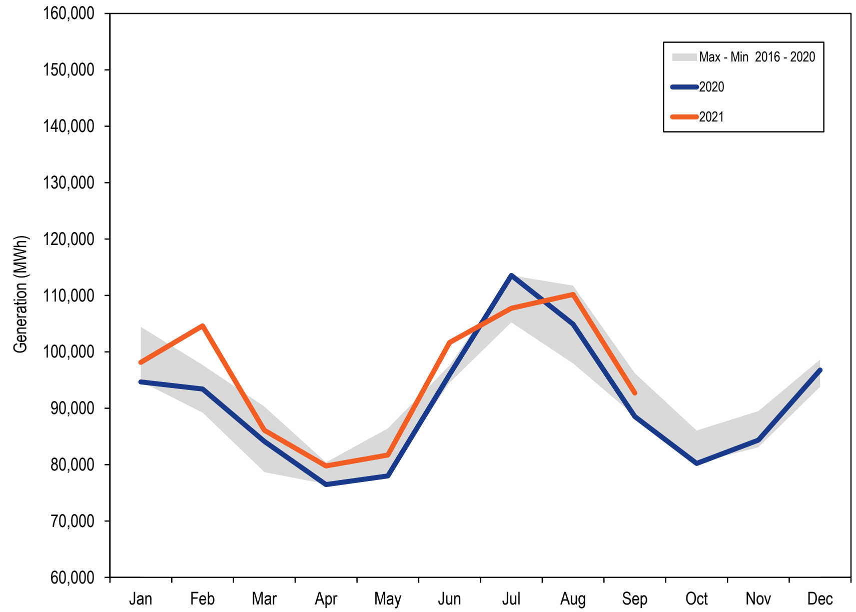
Table 3-3 Real-time average hourly generation and generation plus imports: January through September, 2001 through 2021

	PJM Real-Time Supply (MWh)				Year-to-Year Change			
	Generation		Generation Plus Imports		Generation		Generation Plus Imports	
Jan-Sep	Generation	Standard Deviation	Supply	Standard Deviation	Generation	Standard Deviation	Supply	Standard Deviation
2001	30,304	5,216	33,299	5,571	NA	NA	NA	NA
2002	34,467	8,217	38,207	8,540	13.7%	57.5%	14.7%	53.3%
2003	37,211	6,556	40,815	6,526	8.0%	(20.2%)	6.8%	(23.6%)
2004	45,888	11,035	49,990	11,185	23.3%	68.3%	22.5%	71.4%
2005	81,095	16,710	86,330	17,216	76.7%	51.4%	72.7%	53.9%
2006	84,260	14,696	88,621	15,399	3.9%	(12.1%)	2.7%	(10.5%)
2007	87,297	14,853	91,647	15,668	3.6%	1.1%	3.4%	1.7%
2008	85,241	14,203	90,621	14,646	(2.4%)	(4.4%)	(1.1%)	(6.5%)
2009	78,850	14,242	83,986	14,728	(7.5%)	0.3%	(7.3%)	0.6%
2010	84,086	16,346	88,876	17,001	6.6%	14.8%	5.8%	15.4%
2011	86,966	17,369	91,746	18,276	3.4%	6.3%	3.2%	7.5%
2012	90,367	16,893	95,726	17,810	3.9%	(2.7%)	4.3%	(2.5%)
2013	90,432	15,792	95,639	16,729	0.1%	(6.5%)	(0.1%)	(6.1%)
2014	92,449	16,002	97,922	17,064	2.2%	1.3%	2.4%	2.0%
2015	91,901	16,711	97,896	17,863	(0.6%)	4.4%	(0.0%)	4.7%
2016	92,799	19,003	96,907	19,067	1.0%	13.7%	(1.0%)	6.7%
2017	91,658	15,964	93,639	16,216	(1.2%)	(16.0%)	(3.4%)	(15.0%)
2018	95,561	17,506	97,588	17,747	4.3%	9.7%	4.2%	9.4%
2019	95,531	17,206	96,659	17,378	(0.0%)	(1.7%)	(1.0%)	(2.1%)
2020	92,226	17,790	92,983	17,883	(3.5%)	3.4%	(3.8%)	2.9%
2021	95,792	18,039	96,519	18,173	3.9%	1.4%	3.8%	1.6%

PJM Real-Time, Monthly Average Generation

Figure 3-4 compares the real-time, monthly average hourly generation in 2020 and the first nine months of 2021 with the historic five year range. In February and June 2021, the monthly average hourly generation was higher than the maximum of the past five years, primarily as a result of weather related demand.

Figure 3-4 Real-time monthly average hourly generation: 2020 through September 2021



Day-Ahead Supply

PJM day-ahead average hourly cleared supply in the first nine months of 2021, including INCs and up to congestion transactions, decreased by 9.0 percent from the first nine months of 2020, from 115,205 MWh to 104,785 MWh. When imports are added, PJM average hourly, day-ahead cleared supply in the first nine months of 2021 decreased by 9.0 percent from the first nine months of 2020, from 115,386 MWh to 104,970 MWh. The decrease of day-ahead supply was a result of a decrease in UTCs.

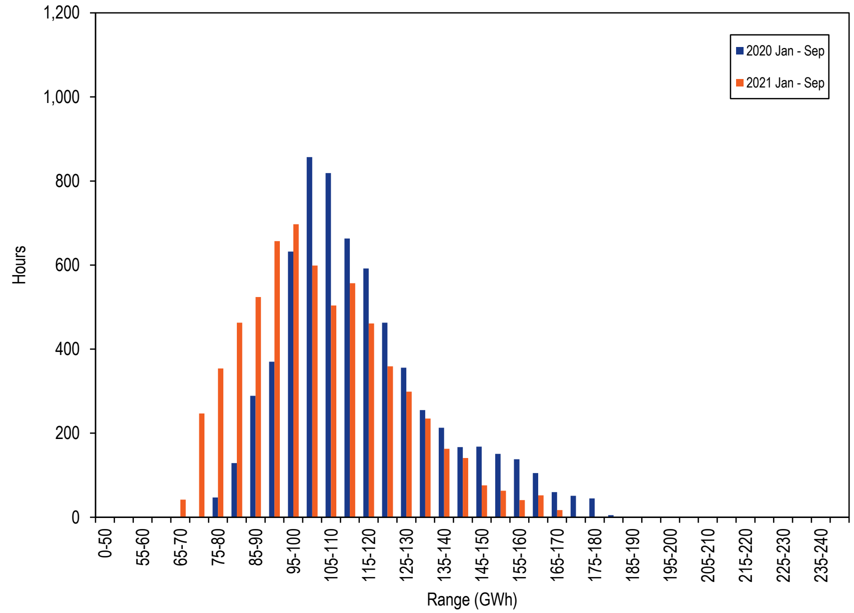
In the PJM Day-Ahead Energy Market, there are five types of financially binding supply offers:

- **Self Scheduled Generation Offer.** Offer to supply a fixed block of MW, 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 MW and corresponding offer prices from a unit.
- **Increment Offer (INC).** Financial offer to supply MW 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 for a specific amount of MW between the transaction source and sink. An up to congestion transaction is a matched pair of an injection and a withdrawal.
- **Import.** An import is an external energy transaction for a specific MW amount scheduled to PJM from another balancing authority. An import must have a valid willing to pay congestion (WPC) OASIS reservation when offered. An import energy transaction that clears the day-ahead energy market is financially binding. There is no link between transactions submitted in the PJM Day-Ahead Energy Market and the PJM Real-Time Energy Market, so an import energy transaction approved in the day-ahead energy market will not physically flow in real time unless it is also submitted through the real-time energy market scheduling process.

PJM Day-Ahead Supply Duration

Figure 3-5 shows the hourly distribution of PJM day-ahead cleared supply, including increment offers, up to congestion transactions, and imports in the first nine months of 2020 and 2021.

Figure 3-5 Distribution of day-ahead cleared supply plus imports: January through September, 2020 and 2021[17]



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

PJM Day-Ahead, Average Supply

Table 3-4 presents day-ahead hourly cleared supply summary statistics for the first nine months of each year from 2001 through 2021. It is the lowest since 2010 for the same time period.

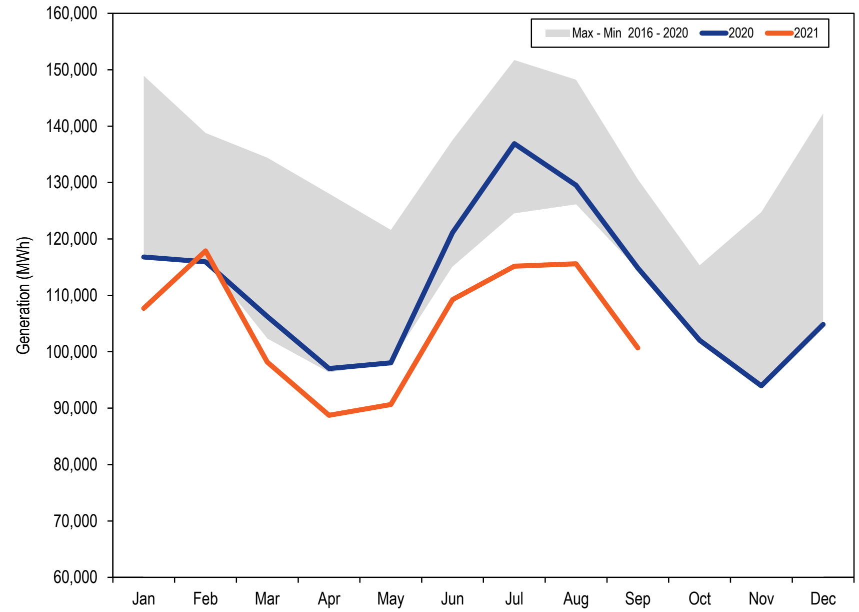
Table 3-4 Day-ahead average hourly cleared supply and cleared supply plus imports: January through September, 2001 through 2021

	PJM Day-Ahead Supply (MWh)				Year-to-Year Change			
	Supply		Supply Plus Imports		Supply		Supply Plus Imports	
Jan-Sep	Supply	Standard Deviation	Supply	Standard Deviation	Supply	Standard Deviation	Supply	Standard Deviation
2001	27,519	4,839	28,279	4,911	NA	NA	NA	NA
2002	30,080	10,982	30,629	10,992	9.3%	126.9%	8.3%	123.8%
2003	40,024	9,079	40,556	9,066	33.1%	(17.3%)	32.4%	(17.5%)
2004	56,103	13,380	56,799	13,349	40.2%	47.4%	40.0%	47.2%
2005	94,437	18,671	96,315	18,963	68.3%	39.5%	69.6%	42.1%
2006	100,888	18,061	103,029	18,071	6.8%	(3.3%)	7.0%	(4.7%)
2007	110,300	17,561	112,575	17,752	9.3%	(2.8%)	9.3%	(1.8%)
2008	107,367	16,601	109,811	16,717	(2.7%)	(5.5%)	(2.5%)	(5.8%)
2009	98,527	17,462	101,123	17,526	(8.2%)	5.2%	(7.9%)	4.8%
2010	108,309	23,295	111,059	23,464	9.9%	33.4%	9.8%	33.9%
2011	116,988	22,722	119,488	23,015	8.0%	(2.5%)	7.6%	(1.9%)
2012	135,213	18,553	137,670	18,788	15.6%	(18.3%)	15.2%	(18.4%)
2013	148,489	18,858	150,785	19,073	9.8%	1.6%	9.5%	1.5%
2014	161,137	23,922	163,431	24,080	8.5%	26.9%	8.4%	26.2%
2015	116,975	20,289	119,349	20,502	(27.4%)	(15.2%)	(27.0%)	(14.9%)
2016	133,089	23,414	134,881	23,403	13.8%	15.4%	13.0%	14.1%
2017	133,377	20,602	134,000	20,710	0.2%	(12.0%)	(0.7%)	(11.5%)
2018	116,068	21,950	116,471	21,939	(13.0%)	6.5%	(13.1%)	5.9%
2019	118,913	20,009	119,249	19,989	2.5%	(8.8%)	2.4%	(8.9%)
2020	115,205	20,611	115,386	20,577	(3.1%)	3.0%	(3.2%)	2.9%
2021	104,785	20,136	104,970	20,154	(9.0%)	(2.3%)	(9.0%)	(2.1%)

PJM Day-Ahead, Monthly Average Cleared Supply

Figure 3-6 compares the day-ahead, monthly average hourly cleared supply, including increment offers and up to congestion transactions for the first nine months of 2020 and 2021 with the historic five year range. The average supply was lower than the minimum of the previous five years in most months as a result of the decrease in UTCs.

Figure 3-6 Day-ahead monthly average cleared hourly supply: January 2020 through September 2021



Real-Time and Day-Ahead Supply

Table 3-5 presents summary statistics for the first nine months of 2020 and 2021, for day-ahead cleared supply and real-time supply. The last two columns of Table 3-5 are the day-ahead supply minus the real-time supply. The first column is the total physical day-ahead generation less the total physical real-time generation and the second column is the total day-ahead supply less the total real-time supply.

Table 3-5 Day-ahead and real-time supply (MWh): January through September, 2020 and 2021

		Day-Ahead					Real-Time		Day-Ahead Less Real-Time	
	Jan-Sep	Generation	INC Offers	Up to Congestion	Imports	Total Supply	Generation	Total Supply	Generation	Supply
Average	2020	92,347	2,443	20,414	181	115,386	92,226	92,983	121	22,403
	2021	95,162	2,308	7,315	185	104,970	95,792	96,519	(630)	8,451
Median	2020	88,682	2,381	20,289	150	110,997	88,622	89,446	60	21,551
	2021	92,790	2,197	7,159	120	102,324	93,229	93,904	(439)	8,420
Standard Deviation	2020	18,695	866	3,911	168	20,577	17,790	17,883	905	2,693
	2021	18,317	1,050	2,997	232	20,154	18,039	18,173	278	1,981
Peak Average	2020	101,768	2,750	21,200	170	125,889	100,618	101,422	1,150	24,466
	2021	104,593	2,825	8,511	171	116,099	104,761	105,571	(168)	10,528
Peak Median	2020	98,564	2,707	20,987	133	121,844	97,190	98,247	1,374	23,597
	2021	102,827	2,808	8,437	105	113,708	102,446	103,277	381	10,431
Peak Standard Deviation	2020	17,984	895	3,869	156	20,001	17,540	17,656	443	2,345
	2021	17,121	1,025	2,783	208	18,111	17,335	17,440	(214)	671
Off-Peak Average	2020	84,004	2,171	19,719	192	106,086	84,795	85,510	(791)	20,575
	2021	86,916	1,857	6,269	197	95,238	87,951	88,604	(1,035)	6,634
Off-Peak Median	2020	81,404	2,130	19,630	155	103,610	82,431	83,213	(1,027)	20,397
	2021	85,029	1,768	5,846	130	92,205	86,187	86,740	(1,158)	5,465
Off-Peak Standard Deviation	2020	14,983	739	3,815	177	16,123	14,380	14,426	603	1,698
	2021	15,063	843	2,779	250	16,481	14,677	14,793	386	1,688

Figure 3-7 shows the average cleared volumes of day-ahead supply and real-time supply by hour of the day for the first nine months of 2021. The day-ahead supply consists of cleared MW of physical generation, imports, increment offers and up to congestion transactions. The real-time supply consists of cleared MW of physical generation and imports.

Figure 3-7 Day-ahead and real-time supply (Average volumes by hour of the day): January through September, 2021

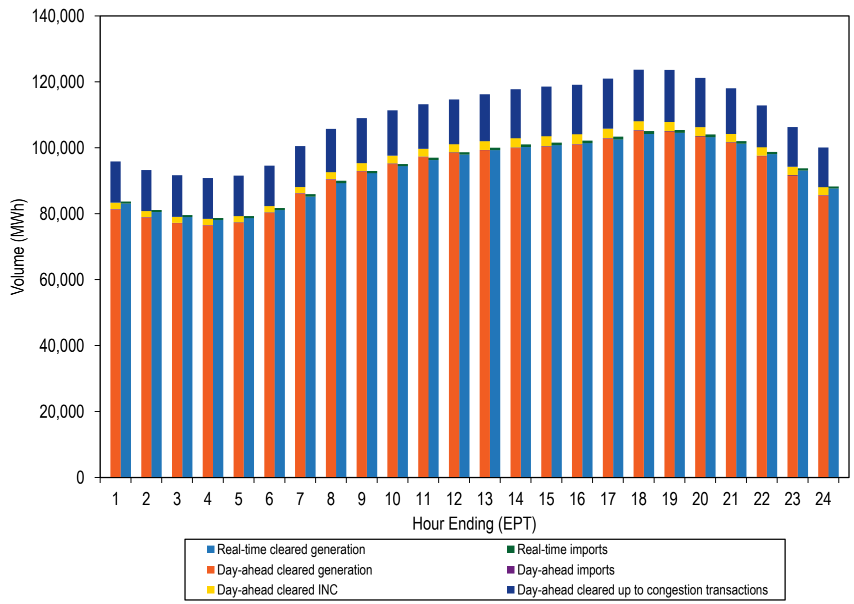
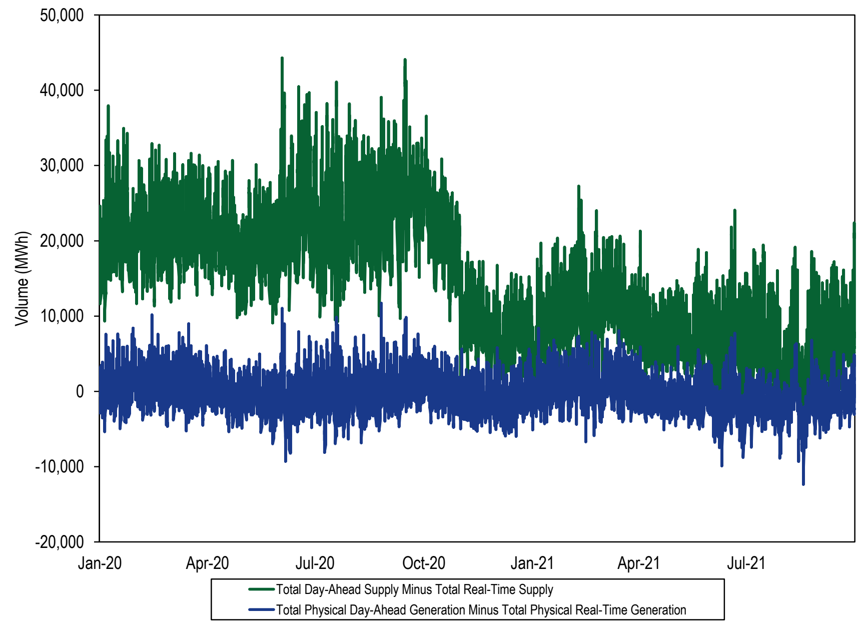


Figure 3-8 shows the difference between the day-ahead and real-time average daily supply in 2020 and the first nine months of 2021.

Figure 3-8 Difference between cleared day-ahead and real-time supply (Average daily volumes): January 2020 through September 2021



Demand

Demand includes physical load and exports and virtual transactions.

Peak Demand

In this section, demand refers to accounting load and exports and, in the day-ahead energy market, includes virtual transactions.[18]

The PJM system real-time hourly peak load plus exports in the first nine months of 2021 was 151,680 MWh in the HE 1800 on August 24, 2021, which was 2,684 MWh, 1.8 percent, higher than the PJM peak load plus exports in the first nine months of 2020, which was 148,996 MWh in the HE 1800 on July 20, 2020.

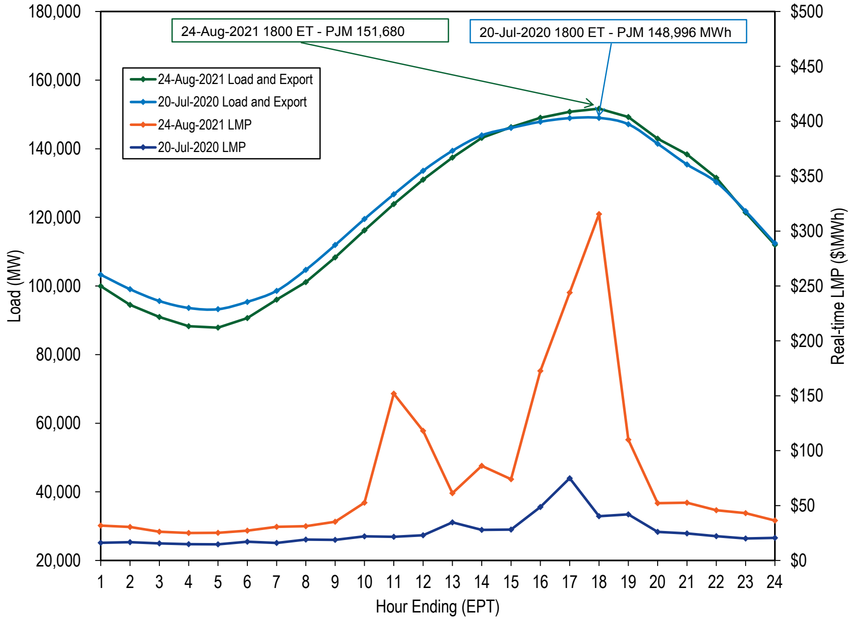
Table 3-6 shows the peak loads plus export for the first nine months of 2009 through 2021.

Table 3-6 Actual footprint peak loads plus export: January through September, 2009 through 2021[19 20]

(Jan - Sep)	Date	Hour Ending (EPT)	PJM Load Plus Export (MWh)	Annual Change (MWh)	Annual Change (%)
2009	Mon, August 10	16	135,923	NA	NA
2010	Wed, July 07	17	149,376	13,453	9.9%
2011	Thu, July 21	17	169,290	19,915	13.3%
2012	Tue, July 17	18	166,081	(3,210)	(1.9%)
2013	Thu, July 18	17	157,277	(8,804)	(5.3%)
2014	Tue, June 17	18	142,428	(14,850)	(9.4%)
2015	Fri, February 20	8	144,850	2,422	1.7%
2016	Thu, August 11	17	154,743	9,893	6.8%
2017	Thu, July 20	16	148,343	(6,400)	(4.1%)
2018	Tue, August 28	17	152,509	4,166	2.8%
2019	Fri, July 19	18	153,589	1,080	0.7%
2020	Mon, July 20	18	148,996	(4,593)	(3.0%)
2021	Tue, August 24	18	151,680	2,684	1.8%

Figure 3-9 compares prices and demand on the peak load days in the first nine months of 2020 and 2021. The average, real-time LMP for July 20, 2020, peak load hour was $40.27 and for August 24, 2021, peak load hour it was $315.42.

Figure 3-9 Peak load and export day comparison: Monday, July 20, 2020 and Tuesday, August 24, 2021



18 PJM reports peak load including accounting load plus an addback equal to PJM's estimated load drop from demand side resources. This will generally result in PJM reporting peak load values greater than accounting load values. PJM's load drop estimate is based on PJM Manual 19: Load Forecasting and Analysis," Attachment A: Load Drop Estimate Guidelines.

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

20 Peak loads shown have been corrected to reflect the accounting load value excluding PJM loss adjustment. The values presented in this table do not include settlement adjustments made prior to January 1, 2017.

Real-Time Demand

PJM real-time average hourly load in the first nine months of 2021 increased by 4.2 percent from the first nine months of 2020, from 85,886 MWh to 89,515 MWh.[21] PJM real-time average hourly demand including exports in the first nine months of 2021 increased by 3.7 percent from the first nine months of 2020, from 91,356 MWh to 94,746 MWh.

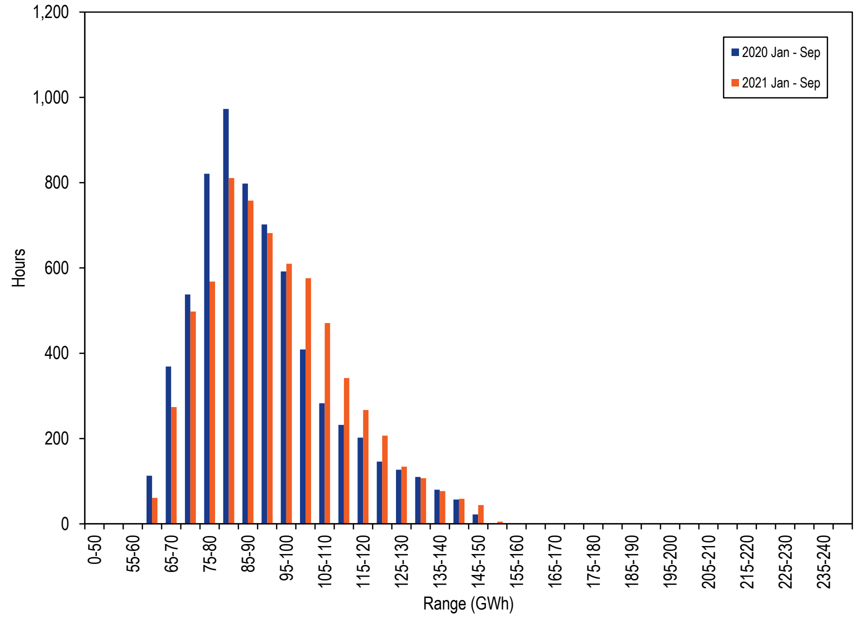
In the PJM Real-Time Energy Market, there are two types of demand:

- **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's checkout process.

PJM Real-Time Demand Duration

Figure 3-10 shows the distribution of PJM real-time hourly load plus exports in the first nine months of 2020 and 2021.[22]

Figure 3-10 Distribution of real-time accounting load plus exports: January through September, 2020 and 2021[23]



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

22 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>.

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

PJM Real-Time, Average Load

Table 3-7 presents real-time hourly demand summary statistics for the first nine months of each year from 2001 through 2021.[24]

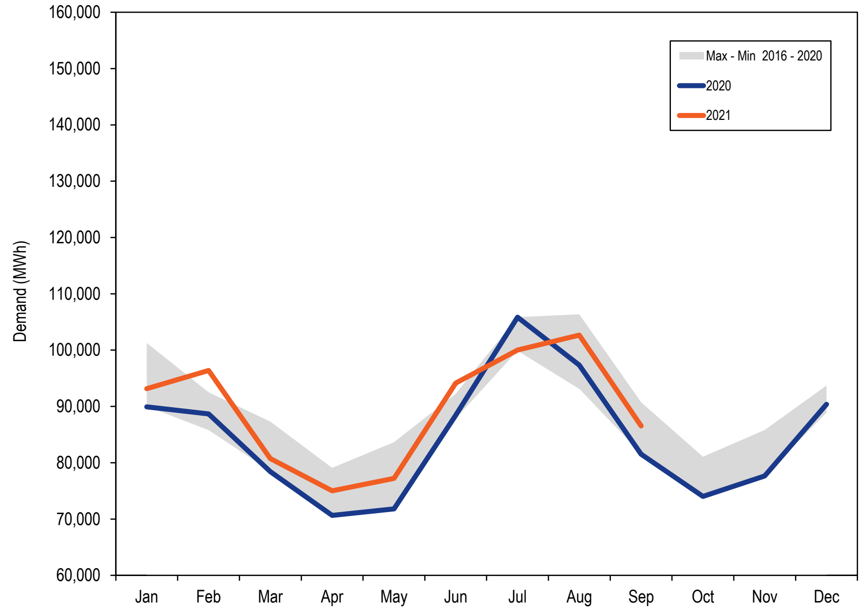
Table 3-7 Real-time average hourly load and load plus exports: January through September, 2001 through 2021

	PJM Real-Time Demand (MWh)				Year to Year Change			
	Load		Load Plus Exports		Load		Load Plus Exports	
Jan-Sep	Load	Standard Deviation	Demand	Standard Deviation	Load	Standard Deviation	Demand	Standard Deviation
2001	31,060	6,156	32,900	5,861	NA	NA	NA	NA
2002	35,715	8,688	37,367	8,878	15.0%	41.1%	13.6%	51.5%
2003	37,996	7,187	39,965	7,120	6.4%	(17.3%)	7.0%	(19.8%)
2004	45,294	10,512	49,176	11,556	19.2%	46.3%	23.0%	62.3%
2005	78,235	17,541	85,295	17,794	72.7%	66.9%	73.4%	54.0%
2006	80,717	15,568	87,326	16,147	3.2%	(11.2%)	2.4%	(9.3%)
2007	83,114	15,386	89,390	16,008	3.0%	(1.2%)	2.4%	(0.9%)
2008	80,611	14,389	87,788	14,893	(3.0%)	(6.5%)	(1.8%)	(7.0%)
2009	76,954	13,879	82,118	14,360	(4.5%)	(3.5%)	(6.5%)	(3.6%)
2010	81,068	16,209	86,994	16,687	5.3%	16.8%	5.9%	16.2%
2011	83,762	17,604	89,628	17,799	3.3%	8.6%	3.0%	6.7%
2012	88,687	17,431	93,763	17,329	5.9%	(1.0%)	4.6%	(2.6%)
2013	89,123	16,384	93,647	16,254	0.5%	(6.0%)	(0.1%)	(6.2%)
2014	90,567	16,662	96,015	16,518	1.6%	1.7%	2.5%	1.6%
2015	91,857	17,211	96,102	17,300	1.4%	3.3%	0.1%	4.7%
2016	90,599	18,183	95,340	18,571	(1.4%)	5.6%	(0.8%)	7.3%
2017	87,243	16,008	91,954	15,794	(3.7%)	(12.0%)	(3.6%)	(15.0%)
2018	91,905	17,064	95,795	17,245	5.3%	6.6%	4.2%	9.2%
2019	89,834	16,794	94,918	16,924	(2.3%)	(1.6%)	(0.9%)	(1.9%)
2020	85,886	17,201	91,356	17,464	(4.4%)	2.4%	(3.8%)	3.2%
2021	89,515	16,875	94,746	17,748	4.2%	(1.9%)	3.7%	1.6%

PJM Real-Time, Monthly Average Load

Figure 3-11 compares the real-time, monthly average load plus exports in 2020 and the first nine months of 2021, with the historic five year range. The February and June monthly average load plus exports in 2021 are higher than the maximum of the past five years.

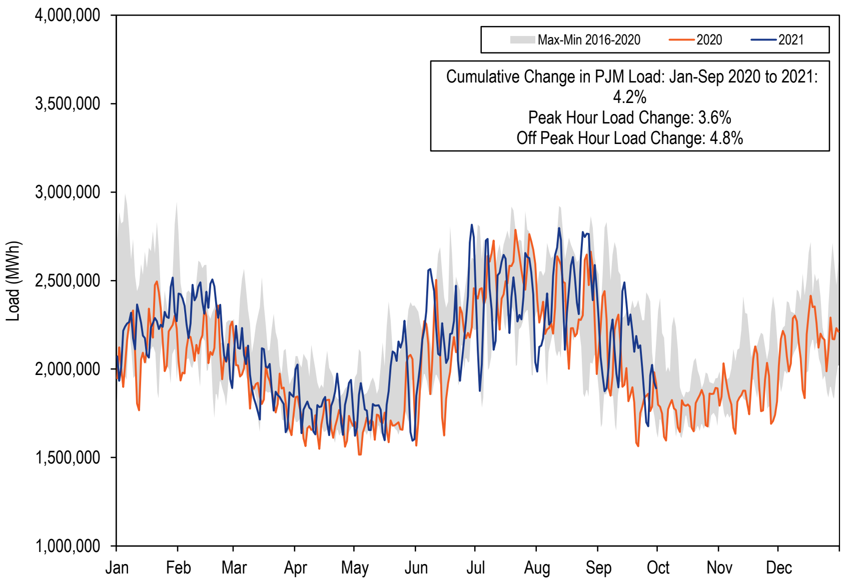
Figure 3-11 Real-time monthly average hourly load plus exports: January 2020 through September 2021



24 Accounting load is used because accounting load is the load customers pay for in PJM settlements. 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. 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 the incorporation of marginal loss pricing in LMP.

Figure 3-12 compares the real-time, average daily load in 2020 and the first nine months of 2021, with the historic five year range.

Figure 3-12 Real-time daily load: January 2020 through September 2021



PJM real-time load is significantly affected by weather conditions. Table 3-8 compares the PJM monthly heating and cooling degree days in 2020 and the first nine months of 2021.[25] Heating degree days increased 9.0 percent, and cooling degree days increased 1.4 percent compared to the first nine months of 2020.

25 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.

Table 3-8 Heating and cooling degree days: January 2020 through September 2021

	2020		2021		Percent Change	
	Heating Degree Days	Cooling Degree Days	Heating Degree Days	Cooling Degree Days	Heating Degree Days	Cooling Degree Days
Jan	698	0	816	0	16.9%	0.0%
Feb	652	0	822	0	26.1%	0.0%
Mar	385	0	405	0	5.3%	0.0%
Apr	279	0	203	8	(27.2%)	0.0%
May	105	59	77	82	(26.7%)	37.8%
Jun	0	262	0	283	0.0%	8.1%
Jul	0	464	0	360	0.0%	(22.4%)
Aug	0	342	0	374	0.0%	9.3%
Sep	13	120	0	158		31.6%
Oct	139	1				
Nov	313	0				
Dec	719	0				
Jan-Sep	2,131	1,247	2,323	1,264	9.0%	1.4%

Day-Ahead Demand

PJM average hourly day-ahead demand in the first nine months of 2021, including DECs and UTCs, decreased by 9.2 percent from the first nine months of 2020, from 109,850 MWh to 99,788 MWh. When exports are added, PJM average hourly day-ahead demand in the first nine months of 2021 decreased by 9.0 percent from the first nine months of 2020, from 113,188 MWh to 102,947 MWh.

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

- **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.
- **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.

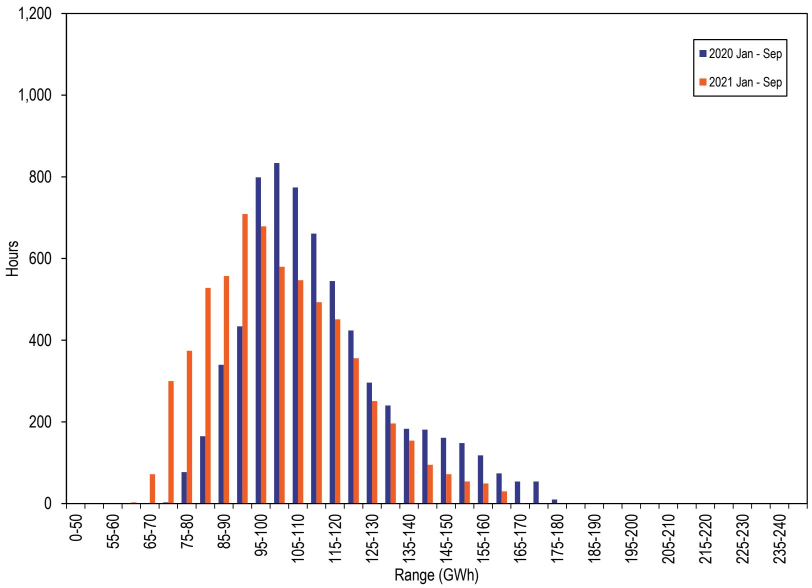
- **Export.** An external energy transaction scheduled from PJM to another balancing authority. An export must have a valid willing to pay congestion (WPC) OASIS reservation when offered. There is no link between transactions submitted in the PJM Day-Ahead Energy Market and the PJM Real-Time Energy Market, so an export energy transaction approved in the day-ahead energy market will not physically flow in real time unless it is also submitted through the real-time energy market scheduling process.

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

PJM Day-Ahead Demand Duration

Figure 3-13 shows the hourly distribution of PJM day-ahead demand for the first nine months of 2020 and 2021.

Figure 3-13 Distribution of day-ahead demand plus exports: January through September, 2020 and 2021[26]



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

PJM Day-Ahead, Average Demand

Table 3-9 shows day-ahead hourly demand for the first nine months of 2001 through 2021. The monthly average hourly demand in first nine months of 2021, with and without exports, is lower than any year since 2010, as a result of the reduction in UTC transaction volumes.

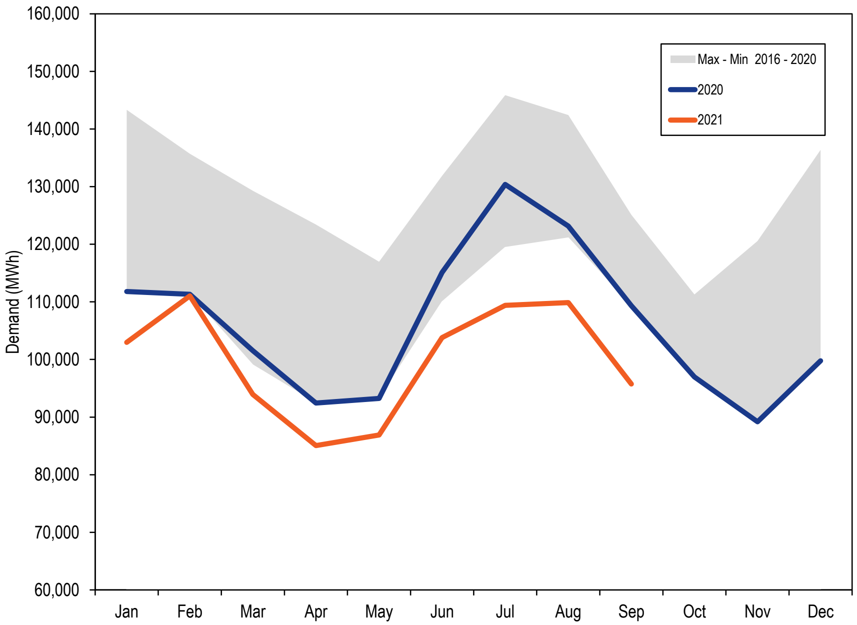
Table 3-9 Day-ahead average hourly demand and demand plus exports: January through September, 2001 through 2021

	PJM Day-Ahead Demand (MWh)				Year to Year Change			
	Demand		Demand Plus Exports		Demand		Demand Plus Exports	
Jan-Sep	Demand	Standard Deviation	Demand	Standard Deviation	Demand	Standard Deviation	Demand	Standard Deviation
2001	33,944	7,016	34,444	6,817	NA	NA	NA	NA
2002	41,634	11,073	41,726	11,120	22.7%	57.8%	21.1%	63.1%
2003	45,371	8,377	45,477	8,354	9.0%	(24.3%)	9.0%	(24.9%)
2004	55,830	13,319	56,558	13,753	23.1%	59.0%	24.4%	64.6%
2005	93,525	19,126	96,302	19,455	67.5%	43.6%	70.3%	41.5%
2006	99,403	18,165	102,520	18,687	6.3%	(5.0%)	6.5%	(3.9%)
2007	107,295	17,580	110,711	17,949	7.9%	(3.2%)	8.0%	(3.9%)
2008	103,586	16,618	107,169	16,810	(3.5%)	(5.5%)	(3.2%)	(6.3%)
2009	96,020	16,995	99,084	17,117	(7.3%)	2.3%	(7.5%)	1.8%
2010	105,018	22,972	109,113	23,286	9.4%	35.2%	10.1%	36.0%
2011	113,724	22,444	117,533	22,651	8.3%	(2.3%)	7.7%	(2.7%)
2012	132,494	18,115	135,840	18,235	16.5%	(19.3%)	15.6%	(19.5%)
2013	145,139	18,667	148,444	18,696	9.5%	3.0%	9.3%	2.5%
2014	156,542	23,584	160,425	23,533	7.9%	26.3%	8.1%	25.9%
2015	113,555	19,789	116,912	19,957	(27.5%)	(16.1%)	(27.1%)	(15.2%)
2016	129,048	22,492	132,405	22,801	13.6%	13.7%	13.3%	14.2%
2017	128,453	20,002	131,572	20,158	(0.5%)	(11.1%)	(0.6%)	(11.6%)
2018	111,589	21,194	114,373	21,392	(13.1%)	6.0%	(13.1%)	6.1%
2019	114,133	19,233	117,048	19,465	2.3%	(9.3%)	2.3%	(9.0%)
2020	109,850	19,762	113,188	20,089	(3.8%)	2.7%	(3.3%)	3.2%
2021	99,788	19,097	102,947	19,632	(9.2%)	(3.4%)	(9.0%)	(2.3%)

PJM Day-Ahead, Monthly Average Demand

Figure 3-14 compares the day-ahead, monthly average hourly demand, including decrement bids and up to congestion transactions in 2020 and first nine months of 2021 with the historic five-year range.

Figure 3-14 Day-ahead monthly average hourly demand plus exports: January 2020 through September 2021



Real-Time and Day-Ahead Demand

Table 3-10 presents summary statistics for the first nine months of 2020 and 2021 day-ahead and real-time demand. The last two columns of Table 3-10 are the day-ahead demand minus the real-time demand: the first column is the total physical day-ahead load (fixed demand plus price-sensitive demand) less the physical real-time load; and the second column is the total day-ahead demand less the total real-time demand. The data show the impact of the reduction in UTC bids on day-ahead demand.

Table 3-10 Cleared day-ahead and real-time demand (MWh): January through September, 2020 and 2021

		Day-Ahead						Real-Time		Day-Ahead Less Real-Time	
Jan-Sep	Year	Fixed Demand	Price Sensitive	DEC Bids	Up-to Congestion	Exports	Total Demand	Load	Total Demand	Load	Demand
Average	2020	84,075	1,188	4,173	20,414	3,338	113,188	85,886	91,356	(623)	21,832
	2021	86,967	1,373	4,134	7,315	3,158	102,947	89,515	94,746	(1,175)	8,201
Median	2020	81,371	1,189	3,542	20,289	3,271	108,962	82,712	87,910	(153)	21,052
	2021	85,016	1,390	3,724	7,159	2,942	100,404	87,428	92,143	(1,022)	8,260
Standard Deviation	2020	16,381	255	2,241	3,911	785	20,089	17,201	17,464	(565)	2,625
	2021	16,123	276	1,872	2,997	1,051	19,632	16,875	17,748	(476)	1,884
Peak Average	2020	92,407	1,307	5,059	21,200	3,493	123,466	94,095	99,601	(382)	23,865
	2021	95,552	1,536	4,845	8,511	3,380	113,824	98,034	103,626	(946)	10,198
Peak Median	2020	90,307	1,328	4,544	20,987	3,412	119,567	91,764	96,495	(129)	23,072
	2021	93,928	1,555	4,505	8,437	3,185	111,461	96,436	101,394	(953)	10,066
Peak Standard Deviation	2020	15,520	274	2,349	3,869	820	19,500	16,777	17,231	(983)	2,269
	2021	14,938	218	1,821	2,783	1,148	17,622	16,047	17,004	(891)	618
Off-Peak Average	2020	76,696	1,083	3,388	19,719	3,200	104,086	78,616	84,054	(837)	20,032
	2021	79,460	1,230	3,512	6,269	2,964	93,436	82,067	86,981	(1,376)	6,454
Off-Peak Median	2020	74,675	1,086	2,922	19,630	3,185	101,653	76,437	81,773	(676)	19,879
	2021	77,724	1,270	3,106	5,846	2,800	90,496	80,559	85,095	(1,565)	5,401
Off-Peak Standard Deviation	2020	13,296	181	1,808	3,815	724	15,745	14,006	14,096	(529)	1,649
	2021	13,091	240	1,685	2,779	916	16,032	13,773	14,436	(442)	1,596

Figure 3-15 shows the average hourly cleared volumes of day-ahead demand and real-time demand for the first nine months of 2021. The day-ahead demand includes day-ahead load, decrement bids, up to congestion transactions, and day-ahead exports. The real-time demand includes real-time load and real-time exports.

Figure 3-15 Day-ahead and real-time demand (Average hourly volumes): January through September, 2021

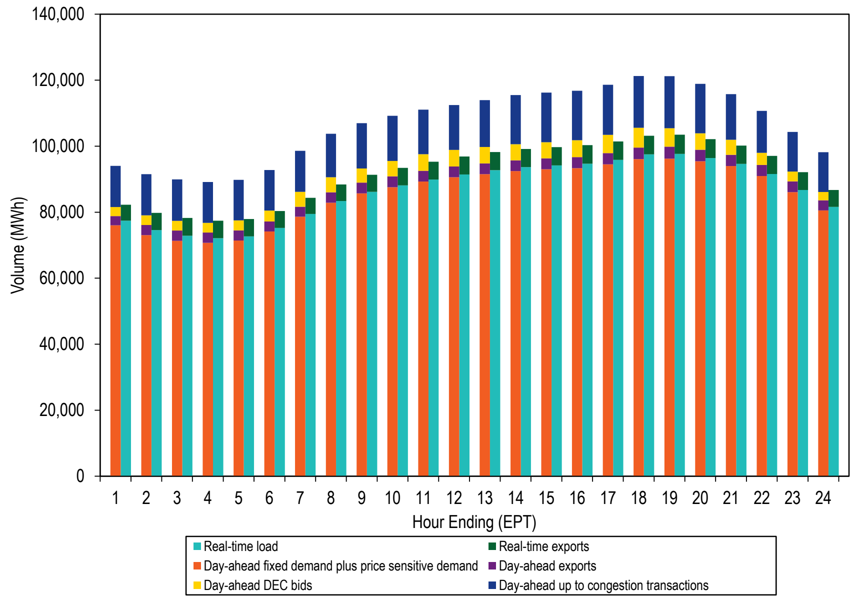
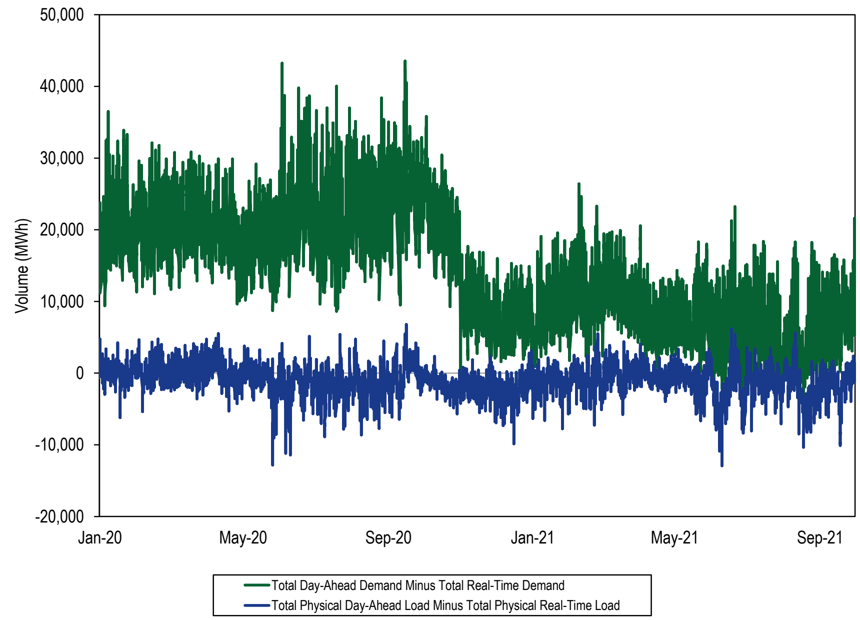


Figure 3-16 shows the difference between the day-ahead and real-time average daily demand for 2020 and the first nine months of 2021.

Figure 3-16 Difference between day-ahead and real-time demand (Average daily volumes): January 2020 through September 2021



Market Behavior

Hourly Offers and Intraday Offer Updates

All participants may make hourly offers. Participants must opt in on a monthly basis to make intraday offer updates. Participants that have opted in can make updates only based on the process defined in their fuel cost policies. Table 3-11 shows the daily average number of units that make hourly offers, that opted in to intraday offer updates and that make intraday offer updates. In the first nine months of 2021, an average of 323 units per day made hourly offers, an increase of 17 units from 2020. In the first nine months of 2021, 428 units opted in for intraday offer updates, an increase of 31 units from 2020. In the first nine months of 2021, an average of 130 units made intraday offer updates each day, a decrease of two units from 2020.

Table 3-11 Daily average number of units making hourly offers, opted in for intraday offers and making intraday offer updates: January through September, 2020 and 2021

	Fuel Type	2020	2021	Difference
Hourly Offers	Natural Gas	289	301	12
	Other Fuels	17	22	5
	Total	306	323	17
Opt In	Natural Gas	348	360	12
	Other Fuels	49	68	19
	Total	397	428	31
Intraday Offer Updates	Natural Gas	127	124	(3)
	Other Fuels	5	6	1
	Total	132	130	(2)

ICAP Must Offer Requirement

Generation capacity resources are required to offer their full ICAP MW into the day-ahead and real-time energy market, or report an outage for the difference.[27] The full installed capacity (ICAP) is the ICAP of the resources that cleared in the capacity market. This is known as the ICAP must offer requirement.

27 OA Schedule 1 § 1.10.1A(d).

Solar, wind, landfill gas, hydro and batteries can satisfy the must offer requirement by self scheduling or offering as dispatchable. There is no defined amount of capacity that these resources must offer. The must offer requirement is thus not applied to these intermittent resource types and compliance is not enforceable.

The current enforcement of the ICAP must offer requirement is inadequate. The problem is a complex combination of generator behavior, and inadequate and inconsistent reporting tools that are not synchronized. Compliance is subject to mistakes and susceptible to manipulation.

Resources are required to submit their available capacity in three different systems. Resources are required to make offers in the energy market. Resources are required to report outages in the Dispatch Application Reporting Tool (eDART) in advance or in real time. Resources are required to report outages in the Generator Availability Data System (eGADS) after the fact. The three applications are not linked in a systematic way to ensure consistency.

Ambient derates are an example issue. When the weather is hotter than test conditions, the capacity of some units is reduced below the ICAP levels. While this fact may be reported by unit owners in eDART and reflected in lower offered MW in the energy market, the derates are never reported as outages in eGADS and are therefore not outages for purposes of defining capacity using EFORd.

The MMU recommends that PJM enforce the ICAP must offer requirement by assigning a forced outage to any unit that is derated in the energy market below its committed ICAP without an outage that reflects the derate.

The MMU recommends that intermittent resources be subject to an enforceable ICAP must offer rule that reflects the limitations of these resources.

Table 3-12 shows average hourly MW, for each month, that violated the ICAP must offer requirement in the first nine months of 2021. On average for all hours, 1,606 MW did not meet the ICAP must offer requirement, but for 10 percent of the hours 3,281 MW did not meet the must offer requirement. These

MW levels are larger than the reserve shortages that triggered scarcity pricing in the first nine months of 2021 and larger than most supply contingencies that led to synchronized reserve events in the first nine months of 2021.

Table 3-12 Average hourly estimated capacity (MW) failing the ICAP must offer requirement: January through September, 2021

Month	90th Percentile	Average	10th Percentile
Jan-21	958	494	97
Feb-21	1,139	683	242
Mar-21	2,194	1,491	554
Apr-21	5,160	4,040	2,772
May-21	3,347	2,575	1,986
Jun-21	1,682	1,069	487
Jul-21	2,570	1,699	796
Aug-21	2,224	1,440	754
Sep-21	1,465	915	433
2021	3,281	1,606	390

The outage data reported in eGADS do not exactly match the Energy Market data submitted in Markets Gateway. For example, economic maximum MW levels submitted in Markets Gateway that reflect expected ambient conditions (including ambient derates) can be inconsistent with the maximum capability submitted in eGADS. Another example is the start and end times of planned outages in the shoulder months. In many situations units are derated in Markets Gateway to reflect an upcoming planned outage for which the unit must ramp down over an extended period but in eGADS the outage start time is not reported until the unit is completely unavailable. These differences can result in units not meeting their ICAP must offer requirement.

Emergency Maximum MW

Generation resources are offered with economic maximum MW and emergency maximum MW. The economic maximum MW is the output level the resource can achieve following economic dispatch. The emergency maximum MW is the output level the resource can achieve when emergency conditions are declared by PJM. The MW difference between the two ratings equals emergency maximum MW. The PJM market rules allow generators to include emergency maximum MW as part of ICAP offered in the capacity market.[28]

28 See 151 FERC ¶ 61,208 at P 476 (2015).

Generation resources have to meet one of four conditions to offer any MW as emergency in the energy market: environmental limits imposed by a federal, state or other governmental agency that significantly limit availability; fuel limits beyond the control of the generation owner; temporary emergency conditions that significantly limit availability; or temporary MW additions not ordinarily available.[29]

The MMU recommends that capacity resources not be allowed to offer any portion of their capacity market obligation as maximum emergency energy.[30] Capacity resources should offer their full output in the energy market and subject to economic dispatch. The result will be incentives for correct reporting of ICAP, more efficient energy market pricing, and a reduction in the need for manual overrides by PJM dispatchers during emergency conditions. Resources that do have capacity that can only be achieved with extraordinary measures could offer such capacity in the energy market but should not take on a capacity market obligation. The capacity performance rules in the capacity market provide incentives for such output during PAI.

Table 3-13 shows average hourly maximum emergency MW, for each month. The levels of maximum emergency MW change hourly, daily and seasonally. For example, 10 percent of hours in July 2021 had maximum emergency MW greater than or equal to 4,430 MW while 10 percent of hours in July 2021 had maximum emergency MW less than 1,747 MW. The hourly average, in the first nine months of 2021, was 2,305 MW offered as maximum emergency, 2.5 percent lower than in 2020.

29 OA Schedule 1 § 1.10.1A (d)

30 This recommendation was accepted by PJM and filed with FERC in 2014 as part of the capacity performance updates to the RPM. See PJM Filing, Attachment A (Redlines of OA Schedule 1 § 1.10.1A(d), EL15-29-000 (December 12, 2014). FERC rejected the proposed change. See 151 FERC ¶ 61,208 at P 476 (2015).

Table 3-13 Maximum emergency MW by month: January through September, 2021

Month	90th Percentile	Average	10th Percentile
Jan-21	2,966	2,310	1,778
Feb-21	2,887	2,304	1,765
Mar-21	2,999	2,262	1,638
Apr-21	2,678	2,049	1,556
May-21	2,345	1,793	1,306
Jun-21	2,737	1,985	1,517
Jul-21	4,430	3,124	1,747
Aug-21	4,053	2,724	1,664
Sep-21	2,737	2,170	1,539
2021	3,376	2,305	1,572

Parameter Limited Schedules

Cost-Based Offers

All resources in PJM are required to submit at least one cost-based offer. Cost-based offers, submitted by capacity resources for a defined set of technologies, are parameter limited based on unit specific parameter limits. Nuclear, wind, solar and hydro units are not subject to parameter limits.

Price-Based Offers

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

The current implementation is not consistent with the goal of having parameter limited schedules, which is to prevent the use of inflexible operating parameters to exercise market power. Instead of ensuring that parameter limits apply, PJM chooses the lower of the price-based schedule and the price-based parameter limited schedule during hot and cold weather alerts. Instead of ensuring that parameter limits apply, PJM chooses the lower of the price-based schedule and the cost-based parameter limited schedule when a resource fails the TPS test. The Commission recognized this flaw in the implementation of market power mitigation in its order to show cause, issued June 17, 2021.[31]

The MMU analyzed the extent of parameter mitigation in the day-ahead energy market when units are committed after failing the TPS test for transmission constraints in the first nine months of 2021. The analysis includes units with technologies that are subject to parameter limits and offer both price-based and cost-based schedules.[32] Table 3-14 shows the number and percentage of day-ahead unit run hours that failed the TPS test but were committed on price schedules. Table 3-14 shows that 30.4 percent of unit hours for units that failed the TPS test were committed on price-based schedules that were less flexible than their cost-based schedules. For effective market power mitigation there would be zero units that fail the TPS test committed with parameters less flexible than their cost-based schedules.

Table 3-14 Parameter mitigation for units failing TPS test: January through September, 2021

Day-ahead Commitment For Units That Failed TPS Test	Day-ahead Unit Hours	Percent Day-ahead Unit Hours
Committed on price schedule less flexible than cost	20,812	30.4%
Committed on price schedule as flexible as cost	5,639	8.2%
Total committed on price schedule without parameter limits	26,451	38.7%
Committed on cost (cost capped)	41,347	60.5%
Committed on price PLS	557	0.8%
Total committed on PLS schedules (cost or price PLS)	41,904	61.3%

The MMU analyzed the extent of parameter mitigation in the day-ahead energy market for units in regions where a cold weather alert or a hot weather alert was declared in the first nine months of 2021. PJM declared cold weather alerts on six days and hot weather alerts on 23 days in the first nine months of 2021.[33] The analysis includes units with technologies that are subject to parameter limits, with a CP commitment, in the zones where the cold or hot weather alerts were declared. Table 3-15 shows that 32.6 percent of unit hours

31 See 175 FERC ¶ 61,231 (June 17, 2021).
32 Nuclear, wind, solar and hydro units are not subject to parameter limits.
33 *2021 Quarterly State of the Market Report for PJM: January through September*, Section 3: Energy Market, at Emergency Procedures.

in the day-ahead energy market were committed on price-based schedules that were less flexible than their price PLS schedules.[34] For effective market power mitigation there would be zero units committed during cold and hot weather alerts with parameters less flexible than their price PLS schedules.

Table 3-15 Parameter mitigation during weather alerts: January through September, 2021

Day-ahead Commitment During Hot And Cold Weather Alerts	Day-ahead Unit Hours	Percent Day-ahead Unit Hours
Committed on price schedule less flexible than PLS	35,981	32.6%
Committed on price schedule as flexible as PLS	6,186	5.6%
Total committed on price schedule without parameter limits	42,167	38.2%
Committed on cost (cost capped)	2,367	2.1%
Committed on price PLS	65,782	59.6%
Total committed on PLS schedules (cost or price PLS)	68,149	61.8%

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

The best solution to the use of inflexible parameters is to require the use of flexible parameters in all offers at all times for capacity resources. Capacity resources are paid to be flexible but that payment will not result in flexible offers in the energy market, the only place it matters, unless there are explicit requirements that energy offers from capacity resources incorporate that flexibility.

If flexible parameters are not required at all times, the use of flexible parameters should be required whenever a unit fails the TPS test and whenever the system is facing emergency conditions. This would require that PJM apply the full set of approved unit specific parameters to a resource that offers any inflexible parameter under these conditions. The selection of the lowest cost offer, based on the financial parameters, would follow the application of PLS parameters.

Currently, PJM commits units on either a cost-based or a price-based schedule. For example, selecting a price-based schedule means selecting the combination of all the operating and financial parameters of such schedule. The financial parameters and the operating parameters must be addressed separately. This approach would simplify the schedule structure implemented in PJM and would allow PJM to effectively mitigate inflexible operating parameters.

The MMU recommends, in order to ensure effective market power mitigation and to ensure that capacity resources meet their obligations to be flexible, that capacity resources be required to use flexible parameters in all offers at all times.

The MMU recommends, if the preferred recommendation is not implemented, that in order to ensure effective market power mitigation, PJM always enforce parameter limited values when the TPS test is failed and during high load conditions such as cold and hot weather alerts and emergency conditions. PJM would separately mitigate the operating parameters and the financial parameters of the offers (incremental offer, startup cost, and no load cost).[35]

Parameter Limits

Beginning June 1, 2020, all capacity resources, including resources in FRR capacity plans, are capacity performance resources. The unit specific parameter limits for capacity performance resources are based on default minimum operating parameter limits posted by PJM by technology type, and any adjustments based on a unit specific review process. These default parameters were based on analysis by the MMU.

The PJM tariff specifies that all generation capacity resources, regardless of the current commitment status, are subject to parameter limits on their cost-based offers. However, the tariff currently does not make it clear what parameter

34 Nuclear, wind, solar and hydro units are not subject to parameter limits.

35 *See* "Comments of the Independent Market Monitor for PJM," Docket No. EL21-78 (October 15, 2021) at 18 - 19.

limit values are applicable for resources without a capacity commitment. The MMU recommends that PJM update the tariff to clarify that all generation resources are subject to unit specific parameter limits on their cost-based offers using the same standard and process as capacity performance resources.

Unit Specific Adjustment Process

Market participants can request an adjustment to the default values of parameter limits for capacity performance resources by submitting supporting documentation which is reviewed by PJM and the MMU. The default minimum operating parameter limits or approved adjusted values are used by capacity performance resources for their parameter limited schedules.

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

The PJM process for the review of unit specific parameter limit adjustments is generally described in Manual 11: Energy and Ancillary Services Market Operations. The standards used by PJM to review the requests are currently not described in the tariff or PJM manuals. The MMU recommends that PJM clearly define the business rules that apply to the unit specific parameter adjustment process, including PJM's implementation of the tariff rules in the PJM manuals to ensure market sellers know the requirements for their resources.

Only certain technology types are subject to limits on operating parameters in their parameter limited schedules.[36] Solar units, wind units, run of river hydro units, and nuclear units are currently not subject to parameter limits. The MMU analyzed, for the units that are subject to parameter limits, the proportion of units that use the default limits published by PJM and the proportion of units that have been provided unit specific adjustments for some of the parameters. Table 3-16 shows, for the delivery year beginning June 1, 2021, the number of units that submitted and had approved unit specific parameter limit adjustments, and the number of units that used the default parameter limits published by PJM.

Table 3-16 Adjusted unit specific parameter limit statistics: 2021/2022 Delivery Year

Technology Classification	Units Using Default Parameter Limits	Units with One or More Adjusted Parameter Limits	Percent of Units with One or More Adjusted Parameter Limits
Aero CT	126	40	24.1%
Frame CT	171	102	37.4%
Combined Cycle	87	32	26.9%
Reciprocating Internal Combustion Engines	68	4	5.6%
Solid Fuel NUG	35	6	14.6%
Oil and Gas Steam	8	13	61.9%
Subcritical Coal Steam	7	57	89.1%
Supercritical Coal Steam	3	38	92.7%
Pumped Storage	8	0	0.0%

Real-Time Values

The Commission rejected PJM's proposed revisions to add RTV rules to the tariff in an order issued on May 28, 2021. In its order, the Commission recognized that RTVs can be used to exercise market power by withholding generation and avoiding market power mitigation.[37]

The real-time values submittal process was never defined in the PJM Operating Agreement. The process was defined only in PJM Manual 11. While there are a number of options for providing real time unit status to PJM operators, PJM created a mechanism for the submission of such values called real-time values (RTVs). Unlike parameter exceptions, the use of real-time values made a unit ineligible for make whole payments, unless the market seller could justify such operation based on an actual constraint.[38] In the case of the notification time parameter, start time parameter, minimum run time and minimum down time parameters, a longer real-time value decreases the likelihood of the

36 For the default parameter limits by technology type, see PJM. "Unit-Specific Minimum Operating Parameters for Capacity Performance and Base Capacity Resources," which can be accessed at <https://www.pjm.com/~/media/committees-groups/committees/elc/postings/20150612-june-2015-capacity-performance-parameter-limitations-informational-posting.ashx>.

37 175 FERC ¶ 61,171 (2021).

38 See OA Schedule 1 § 3.2.3(e).

unit being committed, making the RTV a mechanism for exercising market power through withholding and for failing to meet the obligations of capacity resources.

PJM's proposed RTV mechanism was rejected by the Commission because it would weaken the existing market power mitigation rules including parameter limited schedules.[39]

Beginning August 1, 2021, PJM provided guidance to market sellers that it would no longer accept real-time value submissions that were based on economic reasons, such as due to choosing not to staff a unit. In its response to the Commission's order issued on June 17, 2021, PJM proposed tariff updates to allow generators to submit temporary exceptions during the operating day.[40] These rules require market sellers to justify that the request is based on a physical and actual constraint by submitting supporting documentation within three business days, consistent with the existing temporary parameter exception process. However, the September 15th Response proposes no consequences to market sellers who do not adhere to the proposed tariff defined rules on what is considered a valid justification for temporary exceptions.

Currently, a resource that is staffed or has remote start capability and offers according to its physical capability, and a resource that makes the economic choice not to staff or invest in remote start and economically or physically withholds to decrease the likelihood of commitment, are compensated identically in the capacity market. If a market seller makes an economic decision to not staff the unit or to not have remote start capability, and uses temporary parameter exceptions or RTVs to communicate the longer time to start to PJM, the unit's actual parameters are not recognized as inconsistent with its obligations as a capacity resource, not reflected in forced outages, and not reflected in eligibility for uplift payments. The market seller is able to withhold the unit in the energy market with no defined consequence, while other similarly situated units incur the costs associated with meeting their obligations. Such withholding is an exercise of market power. If market sellers instead represent that they are able to meet the time to start parameters, but the unit is not staffed or the unit is not equipped with remote start capability to meet its unit specific limits, there is no defined consequence for misrepresenting the unit's capability. In its September 15 Response, PJM proposes no explicit defined penalties for such behavior.

Units that override their turn down ratio (economic maximum divided by economic minimum) either use Real Time Values or PJM's fixed gen flag, which functions identically to a real-time value.[41] These resources operate on their parameter limited schedules but override their output limit parameters with no consequence. The only difference between a Real Time Value to override the turn down ratio parameter and the fixed gen flag is that the fixed gen resources receive uplift payments. These resources receive inefficient levels of uplift payments when they have market power. The September 15 Response does not address unstaffed units that refuse to meet their notification time or units that refuse to perform to their turn down ratio parameter by using fixed gen.

There are two options to address the real-time exceptions issue. The immediate option is to clearly define acceptable and unacceptable reasons for requesting a real-time exception. In the case of unacceptable reasons, the unit would not be paid a portion of its otherwise applicable capacity market revenues, e.g. the daily value, if it included the modified parameter values in its offer.

The better option, consistent with the no excuses approach of the capacity performance paradigm and consistent with long term incentives for flexibility, is to not pay any capacity resources an appropriate portion of the daily capacity value of the resource for days when it is not fully available consistent with its parameter limited schedule. If flexibility is valued as a generator attribute, the market design should not provide incentives to be inflexible. An effective market design should reward flexible operation, and ensure that Capacity Performance resources are paid for their capacity only when it meets their required level of flexibility. Without clearly defined consequences, market sellers will continue to submit inflexible parameters. The MMU recommends

39 175 FERC ¶ 61,171 (2021) at P 36.
40 PJM. "Answer of PJM Interconnection LLC," Docket No. EL21-78 (September 15, 2021)("September 15th Response").
41 PJM Markets Gateway User Guide, Section 6.9: Self-schedule a Generating Unit and Ignore PJM Dispatch Instruction at 41, <https://www.pjm.com/~/media/etools/markets-gateway/markets-gateway-user-guide.ashx>.

that resources not be paid the daily capacity payment when unable to operate to their unit specific parameter limits.[42]

Generator Flexibility Incentives under Capacity Performance

In its June 9, 2015, order on capacity performance, the Commission determined that capacity performance resources should be able to reflect actual constraints based on not just the resource physical constraints, but also other constraints, such as contractual limits that are not based on the physical characteristics of the generator.[43] The Commission directed that capacity performance resources with parameters based on nonphysical constraints should receive uplift payments.[44] The Commission directed PJM to submit tariff language to establish a process through which capacity performance resources that operate outside the defined unit specific parameter limits can justify such operation and therefore remain eligible for make whole payments.[45]

A primary goal of the capacity performance market design is to assign performance risk to generation owners and to ensure that capacity prices reflect underlying supply and demand conditions, including the cost of taking on performance risk. The June 9th Order's determination on parameters is not consistent with that goal. By permitting generation owners to establish unit parameters based on nonphysical limits, the June 9th Order weakened the incentives for units to be flexible and 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.

42 *See* Monitoring Analytics LLC, "Real-Time Values," presented at the Markets Implementation Committee Special Session (October 7, 2020) at 12, which can be accessed at <https://www.pjm.com/-/media/committees-groups/committees/mic/2020/20201007/20201007-item-06b-real-time-values-imm.ashx>.

43 151 FERC ¶ 61,208 at P 437 (2015) (June 9th Order).

44 *Id* at P 439.

45 *Id* at P 440.

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

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

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

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

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

Parameter Impacts of Gas Pipeline Conditions

During extreme cold weather conditions, and recently, during hot weather conditions, a number of gas fired generators request temporary exceptions to parameter limits for their parameter limited schedules due to restrictions imposed by natural gas pipelines. The parameters affected include notification time, minimum run time (MRT) and turn down ratio (TDR, the ratio of economic maximum MW to economic minimum MW). When pipelines issue critical notices and enforce ratable take requirements, generators may, depending on the nature of the transportation service purchased, be forced to nominate an equal amount of gas for each hour in a 24 hour period, with penalties for deviating from the nominated quantity. This leads to requests for 24 hour minimum run times and turn down ratios close to 1.0, to avoid deviations from the hourly nominated quantity. Table 3-17 shows the number of units, and the installed capacity MW that submitted parameter exception requests for a 24 hour minimum run time due to gas pipeline restrictions. In the first nine months of 2021, there were 61 units in PJM, with a total installed capacity of 7,514 MW that requested a 24 hour minimum run time on their parameter limited schedules based on pipeline restrictions.

Table 3-17 Units with 24 hour minimum run times due to gas pipeline restrictions: January through September, 2017 to 2021[46]

Year (Jan - Sep)	Number of Units With 24 Hour Minimum Run Time Exceptions	Installed Capacity (MW) With 24 Hour Minimun Run Time Exceptions
2017	-	-
2018	25	3,627
2019	37	5,616
2020	8	3,448
2021	61	7,513

Key parameters like startup and notification time were not included in the PLS matrix in 2017 and prior periods, even though other parameters were subject to parameter limits. 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.

The MMU observed instances when generators submitted temporary parameter exceptions based on claimed pipeline constraints even though these constraints are based on the nature of the transportation service that the generator procured from the pipeline. In some instances, generators requested temporary exceptions based on ratable take requirements stated in pipeline tariffs, even though the requirement is not enforced by the pipelines on a routine basis. If a unit were to be dispatched uneconomically using the inflexible parameters, the unit would receive make whole payments based on these temporary exceptions. The MMU recommends that PJM not

46 The units that requested 24 hour minimum run time on their parameter limited schedules in 2017 belonged to less than four owners. Aggregated data consisting of three or fewer owners is considered confidential and cannot be published. See PJM Manual 31, Section 3.1.

approve temporary exceptions that are based on pipeline tariff terms that are not routinely enforced or on inferior transportation service chosen by the generator.

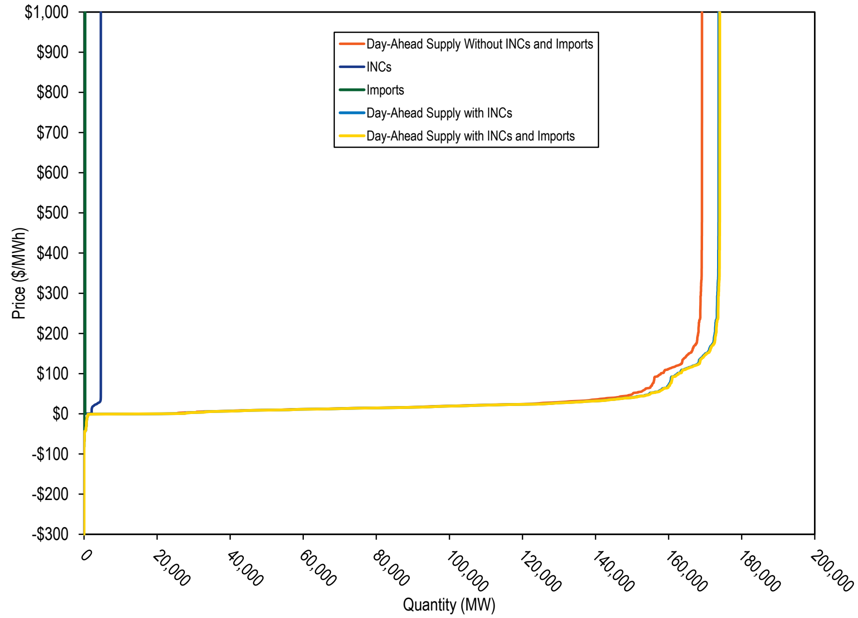
Virtual Offers and Bids

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.

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. Because virtual positions do not require physical generation or load, participants must buy or sell out of their virtual positions at real-time energy market prices. On February 20, 2018, FERC issued an order limiting the eligible bidding points for up to congestion transactions to hubs, interfaces and residual aggregate metered load nodes, and limiting the eligible bidding points for INCs and DECs to the same nodes plus active generation and load nodes.[47] Up to congestion transactions may be submitted between any two buses on a list of 47 buses eligible for up to congestion transaction bidding.[48] 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 3-17 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 2021.

Figure 3-17 Day-ahead aggregate supply curves: 2021 example day



47 162 FERC ¶ 61,139.
48 Prior to November 1, 2012, 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. For the list of eligible sources and sinks for up to congestion transactions, see www.pjm.com "*OASIS-Source-Sink-Link.xls*,"<http://www.pjm.com/~/media/etools/oasis/references/oasis-source-sink-link.ashx>.

Table 3-18 shows the hourly average number of cleared and submitted increment offers and decrement bids by month for 2020 and the first nine months of 2021. The hourly average submitted increment MW decreased by 13.6 percent and cleared increment MW decreased by 5.2 percent in the first nine months of 2021 compared to the first nine months of 2020. The hourly average submitted decrement MW increased by 14.8 percent and cleared decrement MW decreased by 0.7 percent in the first nine months of 2021 compared to the first nine months of 2020.

Table 3-18 Average hourly number of cleared and submitted INCs and DECs by month: January 2020 through September 2021

		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
2020	Jan	2,684	6,395	261	1,063	2,547	5,856	187	662
2020	Feb	2,544	7,043	233	1,046	2,990	6,653	222	702
2020	Mar	2,435	7,119	258	1,069	3,203	7,688	251	762
2020	Apr	2,655	7,738	299	1,167	3,400	8,312	261	840
2020	May	2,695	6,931	254	1,050	4,361	8,257	307	814
2020	Jun	2,353	7,185	235	1,011	5,140	9,843	404	1,083
2020	Jul	2,247	6,936	252	1,071	5,515	11,233	436	1,293
2020	Aug	1,915	6,084	209	973	5,148	10,165	451	1,217
2020	Sep	2,472	6,486	254	1,150	5,217	9,414	468	1,156
2020	Oct	2,492	6,086	309	1,084	4,884	9,696	392	1,229
2020	Nov	2,505	7,000	277	1,125	4,612	9,570	335	1,037
2020	Dec	2,141	5,911	241	974	4,746	10,450	321	1,190
2020	Annual	2,427	6,737	257	1,065	4,318	8,937	337	1,000
2021	Jan	2,208	6,221	259	1,068	3,916	10,076	297	1,194
2021	Feb	2,078	5,476	264	972	5,123	11,556	280	1,303
2021	Mar	2,838	6,524	273	947	4,406	10,063	280	1,149
2021	Apr	3,053	6,998	297	974	3,569	9,188	223	928
2021	May	2,431	6,036	259	885	3,415	8,363	187	862
2021	Jun	1,898	5,290	180	726	4,971	10,854	197	1,024
2021	Jul	2,244	5,797	211	820	3,810	9,054	165	842
2021	Aug	1,788	4,944	202	816	4,016	9,483	182	1,032
2021	Sep	2,226	5,984	252	899	4,080	10,290	276	1,214
2021	Jan-Sep	2,308	5,922	244	901	4,134	9,860	231	1,058

Table 3-19 shows the average hourly number of up to congestion transactions and the average hourly MW by month in 2020 and the first nine months of 2021. The hourly average submitted up to congestion bid MW decreased by 61.3 percent and cleared MW decreased by 64.2 percent in the first nine months of 2021 compared to the first nine months of 2020.

Table 3-19 Average hourly cleared and submitted up to congestion bids by month: January 2020 through September 2021

		Up to Congestion			
Year		Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume
2020	Jan	19,106	37,533	1,127	2,087
2020	Feb	19,415	40,281	1,100	2,133
2020	Mar	19,513	40,998	990	1,970
2020	Apr	18,267	37,298	955	1,859
2020	May	18,028	41,503	1,122	2,425
2020	Jun	23,038	59,520	1,403	2,726
2020	Jul	21,014	64,376	1,227	2,539
2020	Aug	22,478	63,368	1,159	2,306
2020	Sep	22,900	65,866	1,136	2,315
2020	Oct	19,587	55,904	933	1,957
2020	Nov	8,667	21,141	578	1,053
2020	Dec	7,156	17,968	526	942
2020	Annual	18,257	45,501	1,021	2,026
2021	Jan	7,277	20,412	546	1,062
2021	Feb	10,354	23,732	691	1,227
2021	Mar	8,776	24,571	548	1,087
2021	Apr	6,770	21,293	495	1,033
2021	May	6,976	20,674	585	1,164
2021	Jun	7,163	17,808	621	1,132
2021	Jul	6,743	16,386	572	1,041
2021	Aug	5,366	13,542	435	857
2021	Sep	6,659	16,579	471	1,138
2021	Jan-Sep	7,315	19,406	550	1,081

Table 3-20 shows the average hourly number of day-ahead import and export transactions and the average hourly MW from January 2020 through September 2021. In the first nine months of 2021, the average hourly submitted import transaction MW increased by 7.4 percent and the average hourly cleared import transaction MW increased by 0.2 percent compared to the first nine months of 2020. The average hourly submitted and cleared export transaction MW decreased by 4.5 and 5.1 percent compared to the first nine months of 2020.

Table 3-20 Hourly average day-ahead number of cleared and submitted import and export transactions by month: January 2020 through September 2021

		Imports				Exports			
Year	Month	Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume	Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume
2020	Jan	427	445	5	6	3,034	3,041	28	28
2020	Feb	324	346	4	5	2,737	2,742	29	29
2020	Mar	254	269	3	4	3,084	3,085	27	27
2020	Apr	173	188	2	3	3,057	3,062	25	25
2020	May	207	231	3	4	3,075	3,080	23	23
2020	Jun	159	152	2	2	3,782	3,798	31	31
2020	Jul	83	112	2	2	3,907	3,922	31	31
2020	Aug	100	128	2	2	3,909	3,920	29	29
2020	Sep	118	115	2	2	3,424	3,448	28	28
2020	Oct	171	164	2	2	3,268	3,231	26	26
2020	Nov	189	199	2	2	3,158	3,182	32	32
2020	Dec	173	180	2	2	3,106	3,113	31	31
2020	Annual	215	223	3	3	3,298	3,304	28	28
2021	Jan	389	408	4	4	2,854	2,862	30	30
2021	Feb	267	285	3	4	4,581	4,658	41	42
2021	Mar	250	266	2	3	2,493	2,542	27	28
2021	Apr	214	249	3	3	2,364	2,376	24	24
2021	May	217	268	2	3	2,255	2,279	21	21
2021	Jun	155	177	2	2	3,463	3,489	30	30
2021	Jul	139	180	2	3	3,690	3,713	32	33
2021	Aug	116	158	2	3	3,619	3,641	31	31
2021	Sep	108	136	2	2	3,231	3,251	30	31
2021	Jan-Sep	204	235	2	3	3,158	3,187	29	30

Table 3-21 shows the frequency with which generation offers, import or export transactions, up to congestion transactions, decrement bids, increment offers and price-sensitive demand were marginal in January 2020 through September 2021. The frequency of marginal up to congestion transactions deceased significantly in November 2020, due to decreased UTC activity beginning November 1, 2020, when FERC required UTCs to pay uplift.[49]

49 172 FERC ¶ 61,046 (2020).

Table 3-21 Type of day-ahead marginal resources: January 2020 through September 2021

	2020						2021					
	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	27.7%	0.1%	44.7%	10.6%	16.9%	0.0%	23.1%	0.1%	35.7%	24.2%	16.9%	0.0%
Feb	20.7%	0.1%	48.5%	12.5%	18.2%	0.0%	20.3%	0.4%	45.1%	23.1%	11.1%	0.0%
Mar	19.5%	0.0%	52.2%	14.7%	13.6%	0.0%	18.9%	0.1%	33.9%	26.5%	20.6%	0.0%
Apr	18.2%	0.0%	49.3%	16.6%	15.9%	0.0%	19.4%	0.2%	34.4%	21.6%	24.5%	0.0%
May	16.6%	0.1%	55.2%	15.2%	13.0%	0.0%	20.6%	0.2%	35.5%	24.5%	19.1%	0.0%
Jun	14.1%	0.0%	60.8%	15.5%	9.6%	0.0%	21.3%	0.2%	35.8%	30.4%	12.3%	0.0%
Jul	11.8%	0.1%	57.4%	20.4%	10.3%	0.0%	17.6%	0.3%	39.4%	28.8%	13.8%	0.0%
Aug	10.5%	0.0%	55.3%	24.9%	9.2%	0.0%	18.4%	0.5%	37.2%	30.5%	13.4%	0.0%
Sep	13.1%	0.1%	54.8%	21.9%	10.1%	0.0%	18.5%	0.5%	30.6%	29.5%	20.9%	0.0%
Oct	14.7%	0.2%	58.2%	15.0%	12.0%	0.0%						
Nov	21.0%	0.1%	27.6%	27.1%	24.2%	0.0%						
Dec	20.8%	0.2%	32.7%	30.7%	15.5%	0.0%						
Annual	16.5%	0.1%	51.4%	18.8%	13.2%	0.0%	19.7%	0.3%	36.1%	26.5%	17.3%	0.0%

Figure 3-18 shows the monthly volume of bid and cleared INC, DEC and up to congestion bids by month from 2005 through September 2021.

Figure 3-18 Monthly bid and cleared INCs, DECs and UTCs (GWh): January 2005 through September 2021

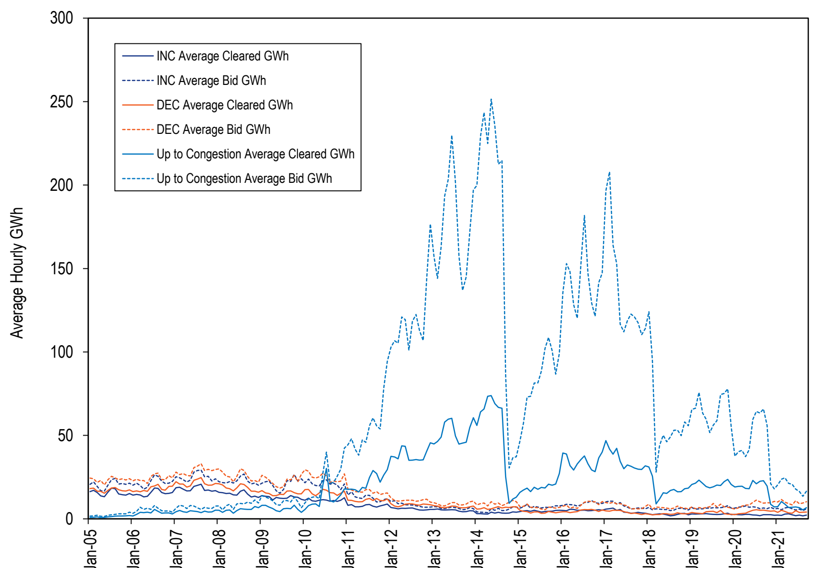
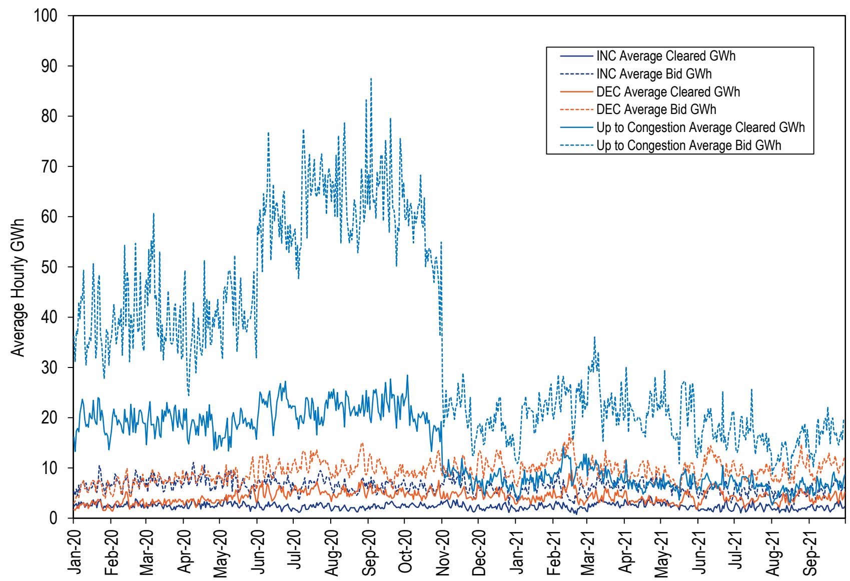


Figure 3-19 shows the daily volume of bid and cleared INC, DEC and up to congestion bids from January 2020 through September 2021.

Figure 3-19 Daily bid and cleared INCs, DECs, and UTCs (GWh): January 2020 through September 2021



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 3-22 shows, in the first nine months of 2020 and 2021, the total increment offers and decrement bids and cleared MW by type of parent organization.

Table 3-22 INC and DEC bids and cleared MWh by type of parent organization (MWh): January through September, 2020 and 2021

	2020 (Jan-Sep)				2021 (Jan-Sep)			
Category	Total Virtual Bid MWh	Percent	Total Virtual Cleared MWh	Percent	Total Virtual Bid MWh	Percent	Total Virtual Cleared MWh	Percent
Financial	87,493,298	86.0%	34,822,073	80.2%	93,549,221	90.6%	34,782,210	82.5%
Physical	14,237,482	14.0%	8,611,229	19.8%	9,751,620	9.4%	7,352,573	17.5%
Total	101,730,780	100.0%	43,433,302	100.0%	103,300,841	100.0%	42,134,783	100.0%

Table 3-23 shows, in the first nine months of 2020 and 2021, the total up to congestion bids and cleared MWh by type of parent organization.

Table 3-23 Up to congestion transactions by type of parent organization (MWh): January through September, 2020 and 2021

	2020 (Jan-Sep)				2021 (Jan-Sep)			
Category	Total Up to Congestion Bid MWh	Percent	Total Up to Congestion Cleared MWh	Percent	Total Up to Congestion Bid MWh	Percent	Total Up to Congestion Cleared MWh	Percent
Financial	295,322,072	89.6%	118,770,263	88.5%	113,251,705	89.1%	41,321,149	86.2%
Physical	34,151,059	10.4%	15,454,488	11.5%	13,875,893	10.9%	6,596,998	13.8%
Total	329,473,130	100.0%	134,224,751	100.0%	127,127,598	100.0%	47,918,147	100.0%

Table 3-24 shows, in the first nine months of 2020 and 2021, the total import and export transactions by whether the parent organization was financial or physical.

Table 3-24 Import and export transactions by type of parent organization (MWh): January through September, 2020 and 2021

		2020 (Jan-Sep)		2021 (Jan-Sep)	
	Category	Total Import and Export MWh	Percent	Total Import and Export MWh	Percent
Day-Ahead	Financial	9,146,059	39.5%	8,180,387	37.4%
	Physical	13,992,116	60.5%	13,721,339	62.6%
	Total	23,138,176	100.0%	21,901,727	100.0%
Real-Time	Financial	12,550,042	30.7%	10,993,824	28.2%
	Physical	28,391,951	69.3%	28,033,310	71.8%
	Total	40,941,994	100.0%	39,027,133	100.0%

Table 3-25 shows increment offers and decrement bids by top 10 locations in the first nine months of 2020 and 2021.

Table 3-25 Virtual offers and bids by top 10 locations (MWh): January through September, 2020 and 2021

2020 (Jan-Sep)					2021 (Jan-Sep)				
Aggregate/Bus Name	Aggregate/Bus Type	INC MWh	DEC MWh	Total MWh	Aggregate/Bus Name	Aggregate/Bus Type	INC MWh	DEC MWh	Total MWh
MISO	INTERFACE	40,963	6,249,294	6,290,257	MISO	INTERFACE	123,315	5,431,289	5,554,604
WESTERN HUB	HUB	491,170	2,067,115	2,558,285	WESTERN HUB	HUB	794,251	1,444,471	2,238,722
AEP-DAYTON HUB	HUB	235,156	1,169,498	1,404,653	LINDENVFT	INTERFACE	44,774	1,357,611	1,402,385
BGE_RESID_AGG	RESIDUAL METERED EDC	225,156	1,049,465	1,274,621	DOM_RESID_AGG	RESIDUAL METERED EDC	122,332	1,157,711	1,280,043
DOM_RESID_AGG	RESIDUAL METERED EDC	140,252	957,543	1,097,795	AEP-DAYTON HUB	HUB	284,262	805,973	1,090,235
NORTHWEST	INTERFACE	596,464	152,419	748,883	BGE_RESID_AGG	RESIDUAL METERED EDC	152,486	884,510	1,036,996
NEW JERSEY HUB	HUB	408,714	303,323	712,037	NYIS	INTERFACE	479,511	498,333	977,844
PECO_RESID_AGG	RESIDUAL METERED EDC	513,491	177,954	691,445	N ILLINOIS HUB	HUB	317,981	509,645	827,627
NYIS	INTERFACE	562,884	126,271	689,154	AEPOHIO_RESID_AGG	RESIDUAL METERED EDC	129,388	609,672	739,060
N ILLINOIS HUB	HUB	275,624	382,788	658,412	COMED_RESID_AGG	RESIDUAL METERED EDC	277,323	414,560	691,883
Top ten total		3,489,874	12,635,669	16,125,543			2,725,623	13,113,775	15,839,398
PJM total		16,064,224	27,437,759	43,501,982			15,122,868	27,079,541	42,202,408
Top ten total as percent of PJM total		21.7%	46.1%	37.1%			18.0%	48.4%	37.5%

Table 3-26 shows up to congestion transactions for the top 10 source and sink pairs and associated source, sink and overall gross revenues before operating reserve charges on each path in the first nine months of 2020 and 2021. While the total cleared MWh were much lower in the first nine months of 2021 compared to the first nine months of 2020, total revenues were higher in the first nine months of 2021. The NIPSCO Interface was eliminated effective June 1, 2020. The NORTHWEST Interface was eliminated effective October 1, 2020. Before the elimination of these interfaces, trades located at these two nodes were among the largest sources of revenue for up to congestion transactions in 2020.[50]

Table 3-26 Cleared up to congestion bids by top 10 source and sink pairs (MWh): January through September, 2020 and 2021

2020 (Jan-Sep)							
Top 10 Paths by Cleared MWh							
Source	Source Type	Sink	Sink Type	Cleared MW	Source Revenue	Sink Revenue	UTC Revenue
NORTHWEST	INTERFACE	N ILLINOIS HUB	HUB	3,619,492	$2,009,727	($1,180,586)	$829,140
AEP GEN HUB	HUB	AEPOHIO_RESID_AGG	AGGREGATE	3,290,217	$736,632	($535,229)	$201,404
NORTHWEST	INTERFACE	COMED_RESID_AGG	AGGREGATE	3,243,735	$2,212,629	($1,291,746)	$920,884
AEP GEN HUB	HUB	EKPC_RESID_AGG	AGGREGATE	2,794,862	$510,612	($87,347)	$423,265
SMECO_RESID_AGG	AGGREGATE	BGE_RESID_AGG	AGGREGATE	2,717,744	$541,148	($577,741)	($36,593)
N ILLINOIS HUB	HUB	AEPIM_RESID_AGG	AGGREGATE	2,163,636	($479,628)	$828,485	$348,857
COMED_RESID_AGG	AGGREGATE	AEPIM_RESID_AGG	AGGREGATE	2,045,907	($580,025)	$1,416,154	$836,129
NORTHWEST	INTERFACE	CHICAGO GEN HUB	HUB	1,851,417	$1,029,251	($599,088)	$430,164
NORTHWEST	INTERFACE	MISO	INTERFACE	1,717,422	$1,371,419	($666,003)	$705,416
OVEC_RESID_AGG	AGGREGATE	DEOK_RESID_AGG	AGGREGATE	1,567,160	$491,465	($566,794)	($75,328)
Top ten total				25,011,592	$7,843,231	($3,259,895)	$4,583,337
PJM total				129,192,958	$11,427,237	$6,183,516	$17,610,753
Top ten total as percent of PJM total				19.4%	68.6%	(52.7%)	26.0%
2021 (Jan-Sep)							
Top 10 Paths by Cleared MWh							
Source	Source Type	Sink	Sink Type	Cleared MWh	Source Revenue	Sink Revenue	UTC Revenue
COMED_RESID_AGG	AGGREGATE	AEPIM_RESID_AGG	AGGREGATE	2,309,469	$1,330,625	($201,191)	$1,129,435
AEP GEN HUB	HUB	EKPC_RESID_AGG	AGGREGATE	1,478,636	$1,352,735	($317,600)	$1,035,135
CHICAGO GEN HUB	HUB	AEPIM_RESID_AGG	AGGREGATE	1,086,379	$584,279	$226,717	$810,996
DOMINION HUB	HUB	DOM_RESID_AGG	AGGREGATE	836,590	($703,909)	$1,264,387	$560,477
MISO	INTERFACE	AEPIM_RESID_AGG	AGGREGATE	792,662	$682,551	$297,142	$979,693
SMECO_RESID_AGG	AGGREGATE	BGE_RESID_AGG	AGGREGATE	787,045	$911,333	($486,304)	$425,029
N ILLINOIS HUB	HUB	AEPIM_RESID_AGG	AGGREGATE	678,607	$526,016	($36,076)	$489,940
WESTERN HUB	HUB	AEP-DAYTON HUB	HUB	656,698	$336,328	$481,008	$817,336
CHICAGO GEN HUB	HUB	EKPC_RESID_AGG	AGGREGATE	646,078	($389,539)	$837,292	$447,753
COMED_RESID_AGG	HUB	AEPOHIO_RESID_AGG	AGGREGATE	629,077	$263,697	$43,535	$307,232
Top ten total				9,901,240	$4,894,117	$2,108,910	$7,003,027
PJM total				47,918,146	$18,584,946	$20,104,068	$38,689,015
Top ten total as percent of PJM total				20.7%	26.3%	10.5%	18.1%

50 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 3-27 shows the average daily number of source-sink pairs that were offered and cleared each month from January 2020 through September 2021. Since November 2020, there has been a decrease in the average number of paths with submitted and cleared bids.

Table 3-27 Number of offered and cleared source and sink pairs: January 2020 through September 2021

		Daily Number of Source-Sink Pairs			
Year	Month	Average Offered	Max Offered	Average Cleared	Max Cleared
2020	Jan	1,658	1,942	1,523	1,857
2020	Feb	1,710	1,975	1,568	1,725
2020	Mar	1,789	2,013	1,591	1,832
2020	Apr	1,804	1,978	1,567	1,760
2020	May	1,913	2,126	1,681	1,900
2020	Jun	1,974	2,111	1,803	2,020
2020	Jul	1,886	2,085	1,749	1,970
2020	Aug	1,760	1,993	1,575	1,854
2020	Sep	1,656	1,851	1,498	1,641
2020	Oct	1,544	1,689	1,358	1,525
2020	Nov	1,306	1,497	1,203	1,387
2020	Dec	1,305	1,508	1,184	1,359
2020	Annual	1,692	1,897	1,525	1,736
2021	Jan	1,286	1,470	1,132	1,302
2021	Feb	1,303	1,514	1,210	1,449
2021	Mar	1,314	1,542	1,189	1,386
2021	Apr	1,309	1,559	1,146	1,388
2021	May	1,329	1,540	1,176	1,395
2021	Jun	1,291	1,412	1,161	1,289
2021	Jul	1,299	1,466	1,161	1,294
2021	Aug	1,403	1,622	1,221	1,469
2021	Sep	1,503	1,610	1,272	1,427
2021	Jan-Sep	1,301	1,509	1,177	1,379

Table 3-28 and Figure 3-20 show total cleared up to congestion transactions and share of the top ten up to congestion paths by transaction type (import, export, or internal) in the first nine months of 2020 and 2021. Total cleared up to congestion transactions decreased by 64.3 percent from 134.2 million MWh in the first nine months of 2020 to 47.9 million MWh in the first nine months of 2021. Internal up to congestion transactions in the first nine months of 2021 were 81.3 percent of all up to congestion transactions compared to 68.4 percent in the first nine months of 2020.

Table 3-28 Cleared up to congestion transactions and share of top 10 paths by type (MW): January through September, 2020 and 2021

	2020 (Jan-Sep)				
	Cleared Up to Congestion Bids				
	Import	Export	Wheel	Internal	Total
Top ten total (MW)	14,218,678	6,928,790	5,636,737	20,482,469	47,266,674
PJM total (MW)	24,337,217	11,725,320	6,344,691	91,817,523	134,224,751
Top ten total as percent of PJM total	58.4%	59.1%	88.8%	22.3%	35.2%
PJM total as percent of all up to congestion transactions	18.1%	8.7%	4.7%	68.4%	100.0%
	2021 (Jan-Sep)				
	Cleared Up to Congestion Bids				
	Import	Export	Wheel	Internal	Total
Top ten total (MW)	2,162,777	2,433,589	497,399	9,650,105	14,743,870
PJM total (MW)	4,164,644	4,180,434	626,144	38,946,924	47,918,146
Top ten total as percent of PJM total	51.9%	58.2%	79.4%	24.8%	30.8%
PJM total as percent of all up to congestion transactions	8.7%	8.7%	1.3%	81.3%	100.0%

Figure 3-20 shows the initial increase and continued increase in internal up to congestion transactions by month following the November 1, 2012, rule change permitting such transactions, until September 8, 2014. The reduction in up to congestion transactions (UTC) that followed a FERC order setting September 8, 2014, as the effective date for any uplift charges subsequently assigned to UTCs, was reversed.[51] There was an increase in up to congestion volume as a result of the expiration of the 15 month refund period for the proceeding related to uplift charges for UTC transactions. In 2018, total UTC activity and the percent of marginal up to congestion transactions again decreased significantly as the result of a FERC order issued on February 20, 2018, and implemented on February 22, 2018.[52] The order limited UTC trading to hubs, residual metered load, and interfaces. UTC activity increased following that reduction. UTC activity decreased again beginning November 1, 2020, after a FERC order requiring UTCs to pay day-ahead and balancing operating reserve charges equivalent to a DEC at the UTC sink point became effective on that date.[53]

51 See 162 FERC ¶ 61,139 (2018).
52 *Id.*
53 See 172 FERC ¶ 61,046 (2020).

Figure 3-20 Monthly cleared up to congestion transactions by type (MW): January 2005 through September 2021

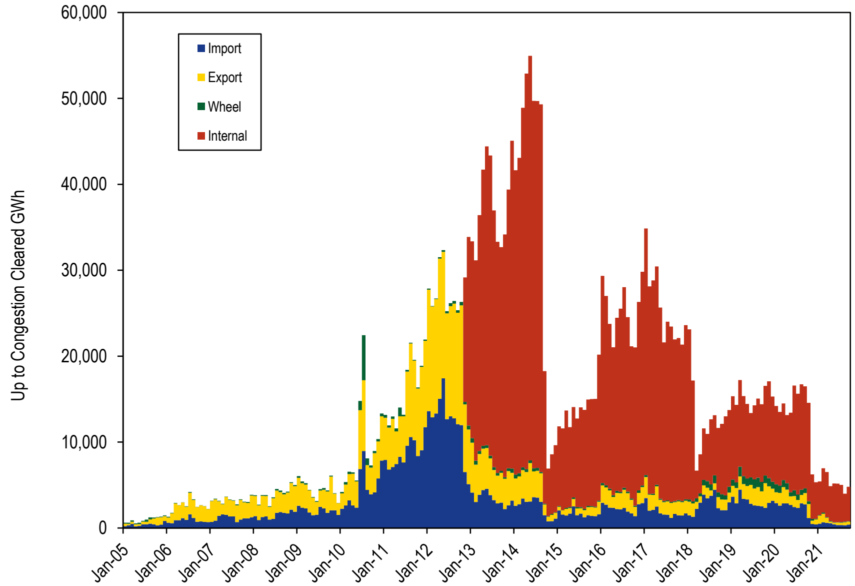
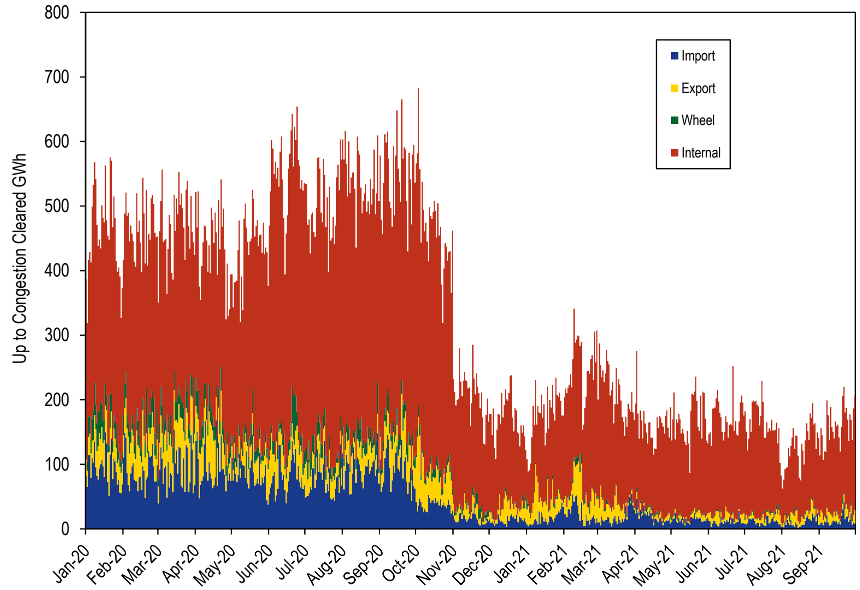


Figure 3-21 shows the daily cleared up to congestion MW by transaction type from January 1, 2020 through September 30, 2021.

Figure 3-21 Daily cleared up to congestion transaction by type (MW): January 2020 through September 2021



One of the goals of the February 2018 FERC order accepting PJM's proposal limiting UTC bidding to hubs, interfaces and residual aggregate metered load nodes, and limiting INC and DEC bidding to the same nodes plus active generation nodes, was to limit the opportunities for traders to profit from opportunities for false arbitrage in which price spreads between the day-ahead and real-time energy markets result from differences in the models used to operate each market that cannot be corrected through virtual bidding.[54]

54 PJM Interconnection, LLC, "Proposed Revisions To Reduce Bidding Points for Virtual Transactions," Docket No. ER18-88, October 17, 2017 at 9–10: "Discrepancies between the models can occur for various reasons despite PJM's best attempts to minimize them…Because individual nodes are more highly impacted by modeling discrepancies than aggregated locations due to averaging, they are often locations where Virtual Transactions can profit. Profits collected by Virtual Transactions in these cases lead to additional costs for PJM members without any benefits."

A key assumption underlying the February 2018 order is that the limited set of nodes available for virtual trading is sufficiently protected from false arbitrage trades because price spreads resulting from modeling differences between the day-ahead and real-time markets are mitigated by the averaging of prices over a large number of buses at aggregate nodes.[55] This assumption is not correct, given the large share of INC, DEC, and UTC profits still attributable to modeling or operational differences between day-ahead and real-time since the February 2018 order.

The assumption that modeling differences are averaged out over aggregate nodes does not hold for multiple nodes in the current list of available up to congestion bidding nodes. The MMU recommends eliminating up to congestion (UTC) bidding at pricing nodes that aggregate only small sections of transmission zones with few physical assets. For this reason, the MMU recommends eliminating UTC bidding at the following nodes: DPLEASTON_RESID_AGG, PENNPOWER_RESID_AGG, UGI_RESID_AGG, SMECO_RESID_AGG, AEPKY_RESID_AGG, and VINELAND_RESID_AGG.

Prices at larger aggregate nodes can also be affected by transmission constraints, especially when constraints are violated and transmission penalty factors are applied in the real-time energy market. Even when the same constraints are modeled in day ahead and real time, constraint violations in real time may result from differences in the day ahead and real time operational environments such as intra hourly ramping limitations, changes to constraint limits, and unit commitments and decommitments. Price spreads due to modeling or operational differences can be in the tens to hundreds of dollars, even when averaged over an aggregate node, and may persist for days or weeks. Virtual traders can often identify and profit from price spreads resulting from systematic modeling and operational differences between day ahead and real time affecting specific generators or aggregate nodes. The MMU recommends eliminating INC, DEC, and UTC bidding at pricing nodes that allow market participants to profit from modeling issues.

55 162 FERC ¶ 61,139 at PP 35–36 ("We accept PJM's proposal to limit eligible bidding points for UTCs to hubs, residual metered load, and interfaces. First, we agree with the IMM's statement that PJM's proposal to limit the UTC bid locations to interfaces, zones, and hubs will minimize false arbitrage opportunities for UTCs currently being pursued through penny bids, as the effect of modeling differences between the day-ahead and real-time markets are minimized at these aggregates.").

Market Performance

PJM locational marginal prices (LMPs) are a direct measure of market performance. The market performs optimally when the market structure provides incentives for market participants to behave competitively. In a competitive market, prices equal the short run marginal cost of the marginal unit of output and reflect the most efficient and least cost allocation of resources to meet demand.

LMP

The behavior 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, surrogate constraints for reactive power and generator stability, or influence prices through manual interventions such as load biasing, changing constraint limits and penalty factors, and committing reserves beyond the requirement.

Real-time and day-ahead energy market load-weighted prices were 68.1 percent and 69.5 percent higher in the first nine months of 2021 compared to the same time period of 2020.

The real-time, average LMP in the first nine months of 2021 increased 67.9 percent from the first nine months of 2020, from $19.95 per MWh to $33.49 per MWh. The real-time, load-weighted average LMP in the first nine months of 2021 increased 68.1 percent from the first nine months of 2020, from $21.22 per MWh to $35.68 per MWh.

The real-time, load-weighted average LMP for the first nine months of 2021 was 58.9 percent higher than the fuel-cost adjusted, load-weighted average, real-time LMP for the first nine months of 2021. If fuel and emission costs in the first nine months of 2021 had been the same as in the first nine months of 2020, holding everything else constant, the load-weighted LMP would have been lower, $22.45 per MWh instead of the observed $35.68 per MWh.

The day-ahead, average LMP in the first nine months of 2021 increased 69.1 percent from the first nine months of 2020, from $19.72 per MWh to $33.34 per MWh. The day-ahead, load-weighted average LMP in the first nine months of 2021 increased 69.5 percent from the first nine months of 2020, from $20.95 per MWh to $35.51 per MWh.

Occasionally, in a constrained market, the LMPs at some pricing nodes can exceed the offer price of the highest cleared generator in the supply curve.[56] In the nodal pricing system, the LMP at a pricing node is the total cost of meeting incremental demand at that node. When there are binding transmission constraints, satisfying the marginal increase in demand at a node may require increasing the output of some generators while simultaneously decreasing the output of other generators, such that the transmission constraints are not violated. The total cost of redispatching multiple generators can at times exceed the cost of marginally increasing the output of the most expensive generator offered. Thus, the LMPs at some pricing nodes exceed $1,000 per MWh, the cap on the generators' offer price in the PJM market.[57]

LMP may, at times, be set by transmission penalty factors, which exceed $1,000 per MWh. When a transmission constraint is binding and there are no generation alternatives to resolve the constraint, the transmission limits may be violated in the market dispatch solution. 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.

Fast Start Pricing

PJM implemented fast start pricing in both the day-ahead and real-time markets on September 1, 2021. Fast start pricing employs a new LMP calculation called the pricing run. The pricing run LMP (PLMP) is now the official settlement LMP in PJM, replacing the dispatch run LMP (DLMP). Unless otherwise specified, the LMP tables and figures show the PLMP for September 1, 2021, and after.

The pricing run calculates LMP using the same optimal power flow algorithm as the dispatch run while simultaneously relaxing the economic minimum and maximum output MW constraints for all eligible fast start units. Fast start units meet the following conditions: Notification time plus start time are less than or equal to one hour; minimum run time is less than or equal to one hour; and units are online and running for PJM, not self-scheduled. This pricing method is intended to allow inflexible resources to set prices with their commitment costs per MWh added to their marginal costs.

56 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) at 19–27.

57 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. See 153 FERC ¶ 61,289 (2015).

DLMP and PLMP

Figure 3-22 shows the daily difference between the PJM real-time, average DLMP and PLMP for September 2021.

Figure 3-22 Real-time, daily average DLMP and PLMP: September 2021

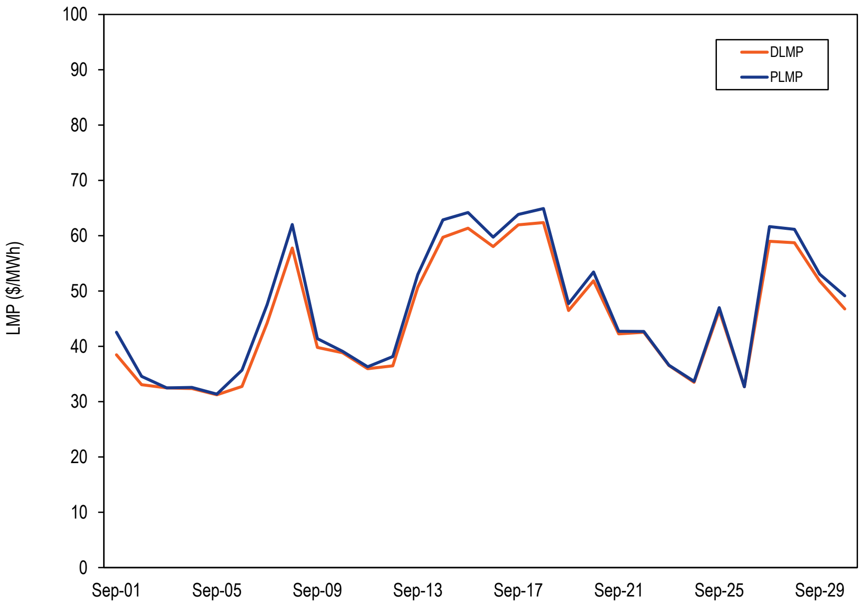


Table 3-29 shows the daily difference between DLMP and PLMP in the real-time and day-ahead markets for September 2021. The average real-time LMP difference was 3.5 percent. Real-time LMP was 3.5 percent higher than it would have been without fast start pricing with no other changes in market structure or market behavior. The largest percent difference was a 10.6 percent increase in the average RT LMP on September 1, 2021. The largest price difference was a $4.26 per MWh increase in the average real-time LMP on September 8, 2021.

Table 3-29 Real-time and day-ahead, daily average PLMP and DLMP (Dollars per MWh): September 2021

	Real Time				Day Ahead			
Date	DLMP	PLMP	Difference	Percent Difference	DLMP	PLMP	Difference	Percent Difference
1-Sep	$38.46	$42.54	$4.09	10.6%	$34.74	$34.75	$0.02	0.0%
2-Sep	$33.06	$34.58	$1.51	4.6%	$33.69	$33.71	$0.01	0.0%
3-Sep	$32.48	$32.48	$0.00	0.0%	$32.93	$32.93	$0.01	0.0%
4-Sep	$32.37	$32.58	$0.21	0.7%	$31.31	$31.32	$0.01	0.0%
5-Sep	$31.24	$31.36	$0.12	0.4%	$31.96	$31.98	$0.01	0.0%
6-Sep	$32.74	$35.68	$2.94	9.0%	$33.44	$33.48	$0.03	0.1%
7-Sep	$44.21	$47.56	$3.34	7.6%	$40.08	$40.15	$0.07	0.2%
8-Sep	$57.77	$62.03	$4.26	7.4%	$39.79	$39.77	($0.01)	(0.0%)
9-Sep	$39.79	$41.39	$1.60	4.0%	$39.73	$39.76	$0.03	0.1%
10-Sep	$38.85	$39.10	$0.25	0.6%	$36.03	$36.05	$0.01	0.0%
11-Sep	$35.96	$36.29	$0.33	0.9%	$38.05	$38.11	$0.07	0.2%
12-Sep	$36.48	$38.16	$1.67	4.6%	$45.61	$45.86	$0.25	0.5%
13-Sep	$50.67	$52.98	$2.31	4.6%	$63.15	$63.40	$0.25	0.4%
14-Sep	$59.72	$62.85	$3.13	5.2%	$56.46	$56.72	$0.26	0.5%
15-Sep	$61.37	$64.20	$2.83	4.6%	$59.95	$60.18	$0.22	0.4%
16-Sep	$58.05	$59.73	$1.68	2.9%	$57.08	$57.39	$0.31	0.6%
17-Sep	$61.98	$63.85	$1.87	3.0%	$58.92	$59.12	$0.20	0.3%
18-Sep	$62.37	$64.91	$2.54	4.1%	$54.90	$55.06	$0.17	0.3%
19-Sep	$46.48	$47.73	$1.25	2.7%	$48.25	$48.51	$0.26	0.5%
20-Sep	$51.84	$53.43	$1.59	3.1%	$49.66	$49.86	$0.20	0.4%
21-Sep	$42.26	$42.72	$0.46	1.1%	$44.54	$44.69	$0.15	0.3%
22-Sep	$42.56	$42.68	$0.12	0.3%	$42.74	$42.85	$0.11	0.3%
23-Sep	$36.53	$36.59	$0.07	0.2%	$39.39	$39.46	$0.07	0.2%
24-Sep	$33.50	$33.66	$0.16	0.5%	$35.48	$35.49	$0.02	0.0%
25-Sep	$46.48	$46.99	$0.52	1.1%	$34.05	$34.05	$0.00	0.0%
26-Sep	$32.68	$32.69	$0.01	0.0%	$33.32	$33.32	$0.00	0.0%
27-Sep	$58.99	$61.66	$2.67	4.5%	$44.59	$44.78	$0.19	0.4%
28-Sep	$58.74	$61.16	$2.42	4.1%	$51.24	$51.39	$0.15	0.3%
29-Sep	$51.82	$53.08	$1.25	2.4%	$51.89	$52.10	$0.21	0.4%
30-Sep	$46.75	$49.13	$2.38	5.1%	$49.90	$50.11	$0.21	0.4%
Average	$45.21	$46.79	$1.59	3.5%	$43.76	$43.88	$0.12	0.3%

Table 3-29 shows the difference between the real-time and day-ahead PLMP for September 2021. Real-time PLMP is 6.6 percent, $2.91 MWh higher than day-ahead PLMP on average.

Table 3-30 Real Time PLMP and Day Ahead PLMP difference (Dollars per MWh): September 2021

	PLMP			
Date	Real Time	Day Ahead	Difference	Percent Difference
1-Sep	$42.54	$34.75	$7.79	22.4%
2-Sep	$34.58	$33.71	$0.87	2.6%
3-Sep	$32.48	$32.93	($0.46)	(1.4%)
4-Sep	$32.58	$31.32	$1.26	4.0%
5-Sep	$31.36	$31.98	($0.62)	(1.9%)
6-Sep	$35.68	$33.48	$2.21	6.6%
7-Sep	$47.56	$40.15	$7.40	18.4%
8-Sep	$62.03	$39.77	$22.26	56.0%
9-Sep	$41.39	$39.76	$1.63	4.1%
10-Sep	$39.10	$36.05	$3.05	8.5%
11-Sep	$36.29	$38.11	($1.83)	(4.8%)
12-Sep	$38.16	$45.86	($7.70)	(16.8%)
13-Sep	$52.98	$63.40	($10.42)	(16.4%)
14-Sep	$62.85	$56.72	$6.14	10.8%
15-Sep	$64.20	$60.18	$4.03	6.7%
16-Sep	$59.73	$57.39	$2.34	4.1%
17-Sep	$63.85	$59.12	$4.73	8.0%
18-Sep	$64.91	$55.06	$9.85	17.9%
19-Sep	$47.73	$48.51	($0.78)	(1.6%)
20-Sep	$53.43	$49.86	$3.58	7.2%
21-Sep	$42.72	$44.69	($1.97)	(4.4%)
22-Sep	$42.68	$42.85	($0.17)	(0.4%)
23-Sep	$36.59	$39.46	($2.87)	(7.3%)
24-Sep	$33.66	$35.49	($1.83)	(5.2%)
25-Sep	$46.99	$34.05	$12.94	38.0%
26-Sep	$32.69	$33.32	($0.63)	(1.9%)
27-Sep	$61.66	$44.78	$16.88	37.7%
28-Sep	$61.16	$51.39	$9.77	19.0%
29-Sep	$53.08	$52.10	$0.98	1.9%
30-Sep	$49.13	$50.11	($0.98)	(2.0%)
Average	$46.79	$43.88	$2.91	6.6%

Fast start pricing affected the difference between PLMP and DLMP in real-time more than in day-ahead. Figure 3-23 shows the hourly difference between DLMP and PLMP for real-time and day-ahead for September 2021.

Figure 3-23 Hourly difference of DLMP and PLMP for real-time and day-ahead: September 2021

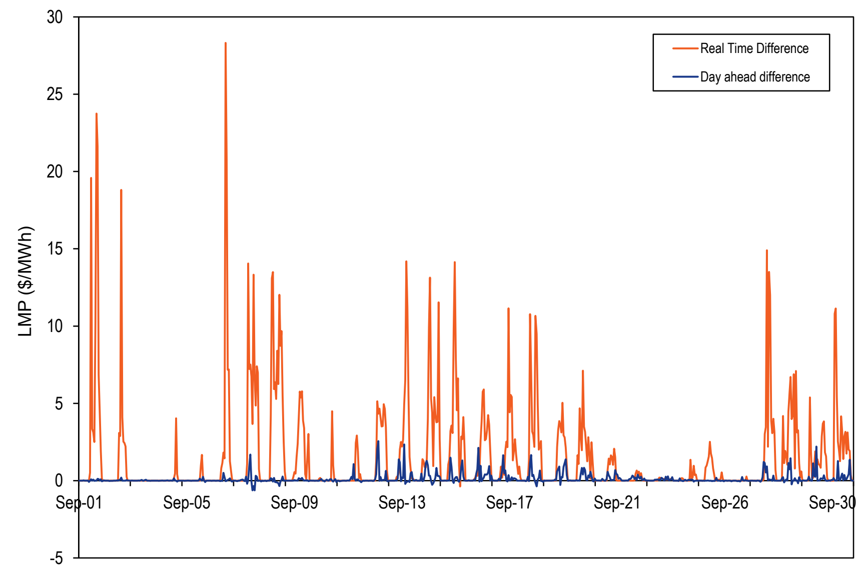


Table 3-29 shows the difference in real-time zonal average DLMP and PLMP for September 2021. Fast start pricing had different impacts by zone. As a result of fast start pricing, the average increase in real-time prices in BGE was 4.0 percent, $1.99 per MWh, while the average increase in real-time prices in DPL was 2.7 percent, $1.05 per MWh.

Table 3-31 Real-time, zonal average PLMP and DLMP (Dollars per MWh): September 2021

ZONE	Average DLMP	Average PLMP	Difference	Difference Pecent
AECO	$39.18	$40.24	$1.06	2.7%
AEP	$45.55	$47.20	$1.65	3.6%
APS	$45.85	$47.54	$1.69	3.7%
ATSI	$44.98	$46.58	$1.60	3.6%
BGE	$49.82	$51.81	$1.99	4.0%
COMED	$43.36	$44.98	$1.62	3.7%
DAY	$47.41	$49.13	$1.72	3.6%
DEOK	$45.52	$47.18	$1.66	3.6%
DOM	$51.93	$53.79	$1.86	3.6%
DPL	$39.32	$40.37	$1.05	2.7%
DUQ	$44.11	$45.68	$1.57	3.6%
EKPC	$45.21	$46.86	$1.65	3.7%
JCPL	$39.74	$40.89	$1.15	2.9%
METED	$45.07	$46.64	$1.57	3.5%
OVEC	$44.66	$46.28	$1.62	3.6%
PECO	$39.16	$40.23	$1.07	2.7%
PENELEC	$42.59	$44.06	$1.46	3.4%
PEPCO	$49.63	$51.60	$1.96	4.0%
PPL	$40.64	$41.94	$1.30	3.2%
PSEG	$39.96	$41.13	$1.17	2.9%
RECO	$40.65	$41.91	$1.26	3.1%

Real-Time Average LMP

Real-time, average LMP is the hourly average LMP for the PJM Real-Time Energy Market.[58]

PJM Real-Time, Average LMP

Table 3-32 shows the PJM real-time, average LMP for the first nine months of 1998 through 2021.[59] The real-time, average LMP in the first nine months of 2021 increased 67.9 percent from the first nine months of 2020, from $19.95 per MWh to $33.49 per MWh.

Table 3-32 Real-time, average LMP (Dollars per MWh): January through September, 1998 through 2021

	Real-Time LMP			Year to Year Change		
Jan-Sep	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$23.18	$16.86	$36.00	NA	NA	NA
1999	$31.65	$18.77	$83.28	36.6%	11.3%	131.3%
2000	$25.88	$18.22	$23.70	(18.2%)	(2.9%)	(71.5%)
2001	$36.00	$25.48	$51.30	39.1%	39.9%	116.4%
2002	$28.13	$20.70	$23.92	(21.9%)	(18.8%)	(53.4%)
2003	$40.42	$33.68	$26.00	43.7%	62.7%	8.7%
2004	$43.85	$39.99	$21.82	8.5%	18.7%	(16.1%)
2005	$54.69	$44.53	$33.67	24.7%	11.4%	54.3%
2006	$51.79	$43.50	$34.93	(5.3%)	(2.3%)	3.7%
2007	$57.34	$49.40	$35.52	10.7%	13.6%	1.7%
2008	$71.94	$61.33	$41.64	25.4%	24.2%	17.2%
2009	$37.42	$33.00	$17.92	(48.0%)	(46.2%)	(57.0%)
2010	$46.13	$37.89	$26.99	23.3%	14.8%	50.6%
2011	$45.79	$37.05	$32.25	(0.7%)	(2.2%)	19.5%
2012	$32.45	$28.78	$21.94	(29.1%)	(22.3%)	(32.0%)
2013	$37.30	$32.44	$22.84	15.0%	12.7%	4.1%
2014	$52.72	$36.06	$74.17	41.3%	11.2%	224.8%
2015	$35.96	$27.88	$30.75	(31.8%)	(22.7%)	(58.5%)
2016	$27.43	$23.61	$15.73	(23.7%)	(15.3%)	(48.8%)
2017	$28.79	$25.28	$16.81	5.0%	7.1%	6.9%
2018	$36.52	$27.26	$33.22	26.8%	7.8%	97.6%
2019	$26.30	$23.39	$17.69	(28.0%)	(14.2%)	(46.8%)
2020	$19.95	$17.87	$10.48	(24.1%)	(23.6%)	(40.7%)
2021	$33.49	$26.82	$24.08	67.9%	50.1%	129.8%

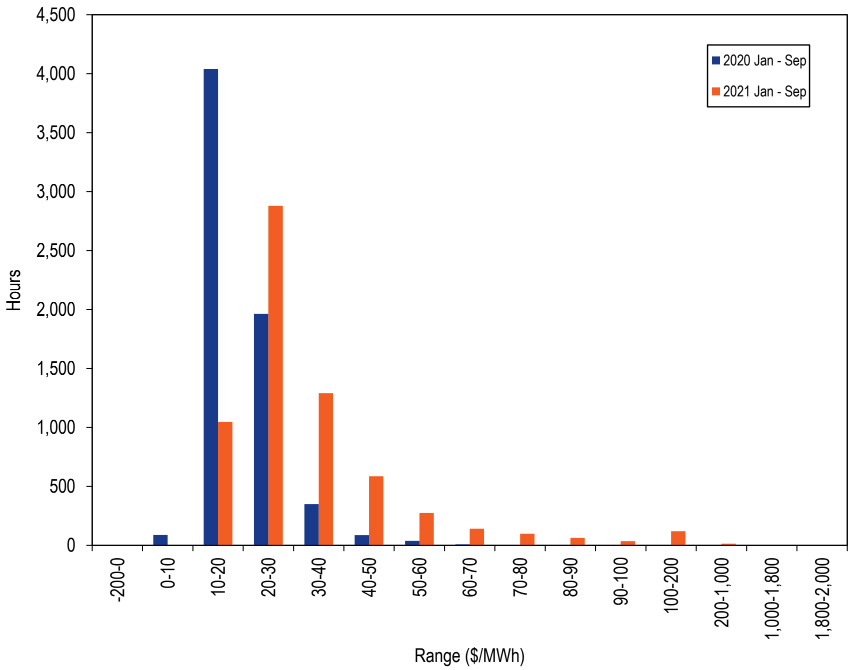
58 See the *Technical Reference for PJM Markets*, at "Calculating Locational Marginal Price," p 16-18 for detailed definition of Real-Time LMP. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

59 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.

PJM Real-Time, Average LMP Duration

Figure 3-24 shows the hourly distribution of PJM real-time, average LMP for the first nine months of 2020 and 2021. There were 4,040 hours with an average LMP between $10 and $20 per MWh in the first nine months of 2020, but only 1,046 hours were in the same range in the first nine months of 2021.

Figure 3-24 Real-time average LMP for the energy market: January through September, 2020 and 2021



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 real-time LMP paid for actual MWh consumed during a year. Load-weighted, average LMP is the average of PJM hourly LMP, each weighted by the PJM total hourly load.

PJM Real-Time, Load-Weighted Average LMP

Table 3-33 shows the PJM real-time, load-weighted average LMP for the first nine months of 1998 through 2021. The real-time, load-weighted average LMP in the first nine months of 2021 increased 68.1 percent from the first nine months of 2020, from $21.22 per MWh to $35.68 per MWh.

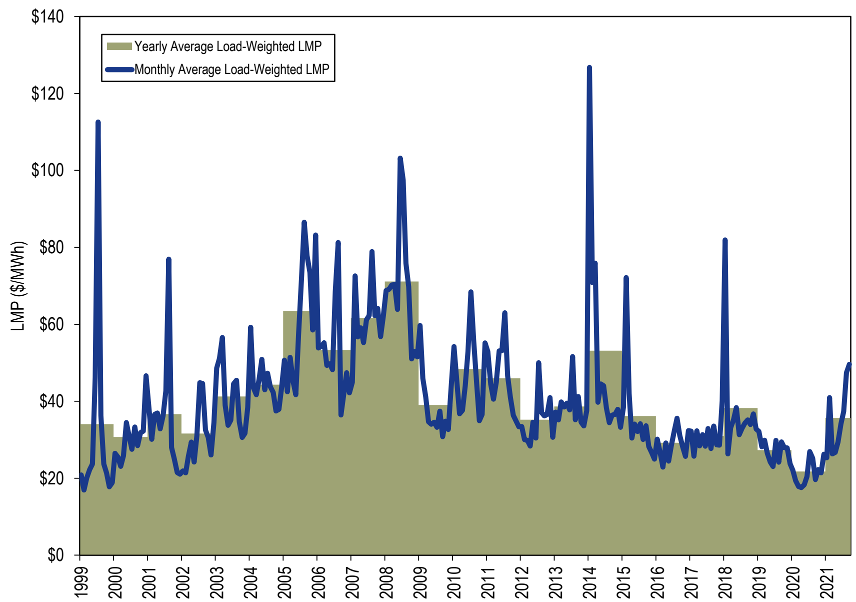
Table 3-33 Real-time, load-weighted average LMP (Dollars per MWh): January through September, 1998 through 2021

	Real-Time, Load-Weighted, Average LMP			Year to Year Change		
Jan-Sep	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$26.06	$18.20	$44.65	NA	NA	NA
1999	$38.65	$20.02	$104.17	48.3%	10.0%	133.3%
2000	$28.49	$19.30	$26.89	(26.3%)	(3.6%)	(74.2%)
2001	$40.96	$28.18	$64.57	43.8%	46.0%	140.1%
2002	$31.95	$23.09	$29.14	(22.0%)	(18.1%)	(54.9%)
2003	$43.57	$38.17	$26.53	36.3%	65.3%	(9.0%)
2004	$46.44	$43.03	$21.89	6.6%	12.7%	(17.5%)
2005	$60.44	$50.10	$36.52	30.2%	16.4%	66.9%
2006	$56.39	$46.82	$40.70	(6.7%)	(6.5%)	11.4%
2007	$61.83	$55.12	$37.98	9.7%	17.7%	(6.7%)
2008	$77.27	$66.73	$43.80	25.0%	21.1%	15.3%
2009	$39.57	$34.57	$19.04	(48.8%)	(48.2%)	(56.5%)
2010	$49.91	$40.33	$29.65	26.2%	16.7%	55.7%
2011	$49.48	$38.72	$37.02	(0.9%)	(4.0%)	24.8%
2012	$35.02	$29.84	$25.44	(29.2%)	(22.9%)	(31.3%)
2013	$39.75	$33.61	$26.47	13.5%	12.6%	4.0%
2014	$58.60	$37.93	$86.22	47.4%	12.8%	225.8%
2015	$38.94	$29.09	$33.95	(33.5%)	(23.3%)	(60.6%)
2016	$29.32	$24.60	$17.13	(24.7%)	(15.4%)	(49.6%)
2017	$30.36	$26.26	$18.81	3.5%	6.7%	9.8%
2018	$39.43	$28.78	$36.82	29.9%	9.6%	95.7%
2019	$27.60	$24.23	$18.69	(30.0%)	(15.8%)	(49.2%)
2020	$21.22	$18.66	$11.53	(23.1%)	(23.0%)	(38.3%)
2021	$35.68	$28.41	$26.03	68.1%	52.3%	125.8%

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

Figure 3-25 shows the PJM real-time monthly and annual load-weighted LMP for January 1999 through September 2021.

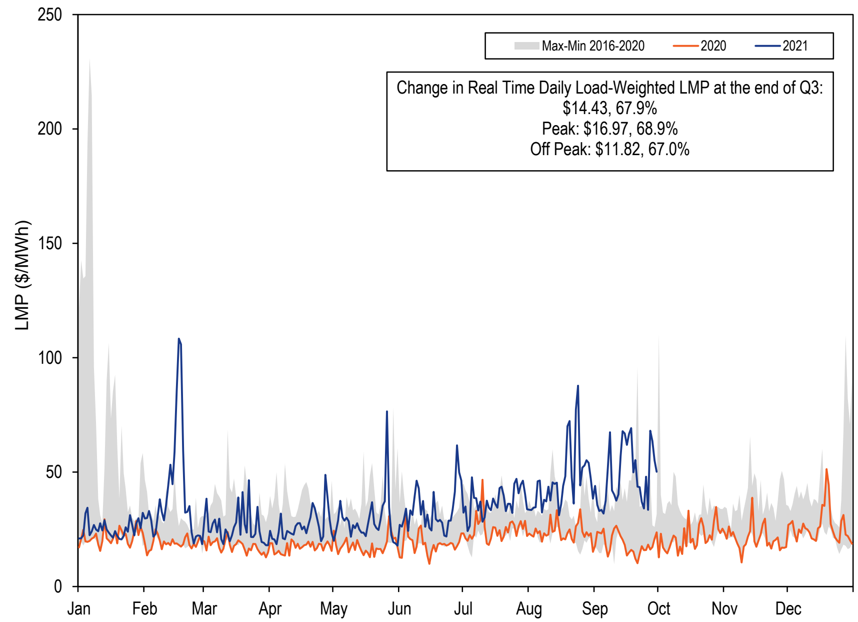
Figure 3-25 Real-time, monthly and annual, load-weighted average LMP: January 1999 through September 2021



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

Figure 3-26 shows the PJM real-time, daily, load-weighted LMP for 2020 through the first nine months of 2021.

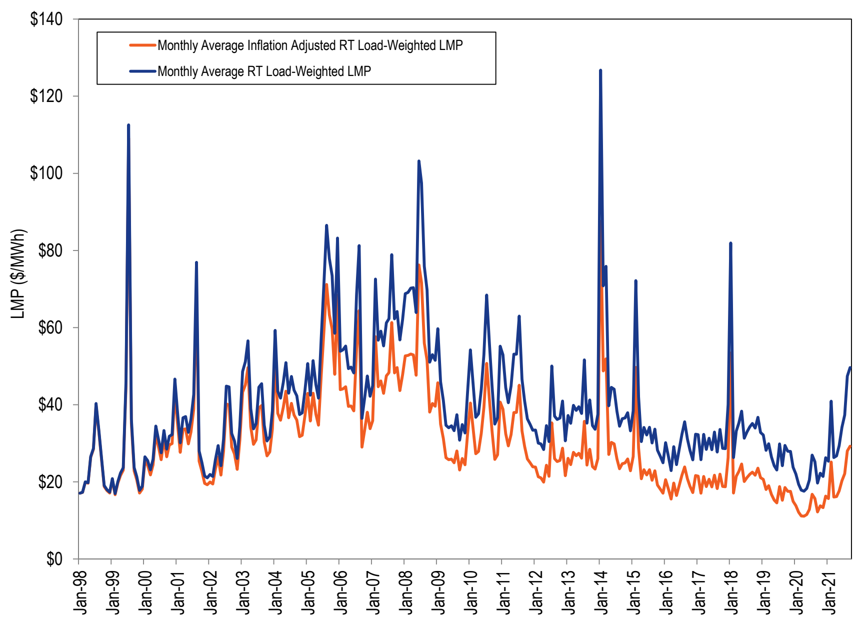
Figure 3-26 Real-time, daily, load-weighted average LMP: January 2020 through September 2021



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

Figure 3-27 shows the PJM real-time, monthly, load-weighted average LMP and inflation adjusted, monthly, load-weighted average LMP from January 1998 through September 2021.[60] Table 3-34 shows the PJM real-time, load-weighted average LMP and inflation adjusted load-weighted, average LMP for the first nine months of every year from 1998 through 2021. The PJM real-time inflation adjusted, load-weighted average LMP for the first nine months of 2021 was the fifth lowest value since PJM real-time markets started on April 1, 1999 at $21.39 per MWh. The real-time, inflation adjusted, monthly, load-weighted average LMP for April 2020 was the lowest monthly value since PJM markets started in April 1999 at $11.08 per MWh.

Figure 3-27 Real-time, monthly, load-weighted average LMP unadjusted and adjusted for inflation: January 1998 through September 2021



60 To obtain the inflation adjusted, monthly, load-weighted, average LMP, the PJM system-wide load-weighted average LMP is deflated using the US Consumer Price Index for all items, Urban Consumers (base period: January 1998), published by *Bureau of Labor Statistics*. <http://download.bls.gov/pub/time.series/cu/cu.data.1.AllItems> (Accessed October 13, 2021)

Table 3-34 Real-time, load-weighted average LMP unadjusted and adjusted for inflation: January through September, 1998 through 2021

	Load-Weighted, Average LMP Jan-Sep	Inflation Adjusted Load-Weighted, Average LMP Jan-Sep
1998	$26.06	$25.86
1999	$38.65	$37.55
2000	$28.49	$26.82
2001	$40.96	$37.39
2002	$31.95	$28.72
2003	$43.57	$38.33
2004	$46.44	$39.85
2005	$60.44	$50.09
2006	$56.39	$45.16
2007	$61.83	$48.36
2008	$77.27	$57.70
2009	$39.57	$29.93
2010	$49.91	$37.04
2011	$49.48	$35.59
2012	$35.02	$24.68
2013	$39.75	$27.58
2014	$58.60	$40.11
2015	$38.94	$26.60
2016	$29.32	$19.77
2017	$30.36	$20.05
2018	$39.43	$25.45
2019	$27.60	$17.49
2020	$21.22	$13.27
2021	$35.68	$21.39

Real-Time Dispatch and Pricing

In the first nine months of 2021, real-time dispatch and pricing were not temporally aligned. The PJM Real-Time Energy Market consists of a series of applications that produce the generator dispatch for energy and reserves, and five minute locational marginal prices (LMPs). These applications include the ancillary services optimizer (ASO), real-time security constrained economic dispatch (RT SCED), and the locational pricing calculator (LPC).[61] The final real-time LMPs and ancillary service clearing prices are determined for every five minute interval by LPC.

61 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Rev. 115 (June 1, 2021)

Real-Time SCED and LPC

LPC uses data from an approved RT SCED solution that was used to dispatch the resources in the system. RT SCED solves to meet load and reserve requirements forecast at a future point in time, called the target time. Prior to 2021, on average, PJM operators approved more than one RT SCED solution per five minute target time to send dispatch signals to resources. In the first nine months of 2021, on average, PJM operators approved one RT SCED solution per five minute target time to send dispatch signals to resources. PJM uses a subset of these approved RT SCED solutions in LPC to calculate real-time LMPs every five minutes. Prior to October 15, 2020, LPC used the latest available approved RT SCED solution to calculate prices, regardless of the target dispatch time of the RT SCED solution, but LPC assigned the prices to a five minute interval that did not contain the target time of the RT SCED case it used. On October 15, 2020, PJM updated its pricing process to use an approved RT SCED solution that solves for the same target time as the end of each five minute pricing interval to calculate LMPs applicable for that five minute interval, although the SCED cases are still for 10 minutes ahead while the LPC cases are for each five minute interval. As a result, under the default timing of case approvals, resources follow the dispatch signal in the first five minutes after the RT SCED case approval and the corresponding pricing occurs five minutes after the same case approval, when resources are following a new dispatch signal.

Table 3-35 shows, on a monthly basis in the first nine months of 2020 and 2021, the number of RT SCED case solutions, the number of solutions that were approved and the number and percent of approved solutions used in LPC. Until February 24, 2020, RT SCED was automatically executed every three minutes with operators having the ability to execute additional cases in between the automatically executed cases. Beginning February 24, 2020, PJM changed the RT SCED automatic execution frequency to once every four minutes. On June 22, 2020, PJM changed the RT SCED execution frequency to once every five minutes. PJM operators continue to have the ability to execute additional RT SCED cases. PJM retains the discretion to change the automatic RT SCED execution frequency at any time, as the frequency is not documented in the PJM market rules. Prior to June 3, 2021, each execution of RT SCED produced three solutions, using three different levels of load bias. Beginning June 3, 2021, each execution of RT SCED produces five solutions, using five different levels of load bias. Since prices are calculated every five minutes while five SCED solutions are produced every five minutes, there is, by definition, a larger number of SCED solutions than there are five minute intervals in any given period.

Table 3-35 shows that in the first nine months of 2021, 92.0 percent of approved RT SCED solutions that were used to send dispatch signals to generators were used in calculating real-time energy market prices, compared to 79.4 percent in the first nine months of 2020. The percent of approved solutions used for pricing increased in 2020 with the decrease in the frequency of executed RT SCED cases.

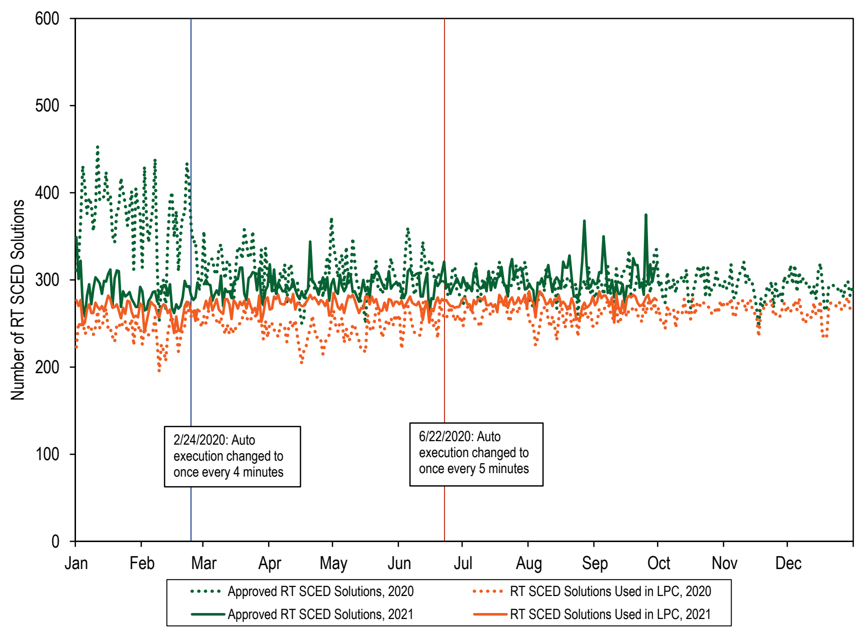
Figure 3-28 shows the daily number of RT SCED cases approved by PJM operators to send dispatch signals to resources and the subset of approved RT SCED cases that were used in LPC to calculate LMPs in 2020 and the first nine months of 2021, and the dates when the frequency of RT SCED auto execution was changed in 2020. Figure 3-28 shows that changing the auto execution frequency of RT SCED from once every three minutes to once every four minutes on February 24, 2020 and to five minutes on June 22, 2020 reduced the number of approved RT SCED cases used to send dispatch signals in 2020. This change in the frequency of approved solutions reduced the difference between the number of approved solutions and the number of solutions used in pricing in the first nine months of 2021 relative to the first nine months of 2020.

PJM's process for solving and approving RT SCED cases, and selecting approved RT SCED cases to use in LPC to calculate LMPs has inconsistencies that lead to downstream impacts for energy and reserve dispatch and settlements. PJM does not link dispatch and settlement intervals. RT SCED moved from automatically executing a case every three minutes to every five minutes in 2020, while settlements are linked to five minute intervals. In the first nine months of 2021, the frequency of automatic execution of RT SCED cases was one every five minutes. RT SCED solves the dispatch problem for a target time that is generally 14 minutes in the future. An RT SCED case is approved and sends dispatch signals to generators based on a 10 minute ramp time. The look ahead time for the load forecast and the look ahead time for the resource dispatch target do not match, and a new RT SCED case overrides the previously approved case before resources have time to achieve the previous target dispatch. Prior to October 15, 2020, the interval that was priced in LPC was consistently before the target time from the RT SCED case used for the dispatch signal. LPC took the most recently approved RT SCED case to calculate LMPs for the present five minute interval. For example, the LPC case that calculated prices for the interval ending 10:05 EPT used an approved RT SCED case that sent MW dispatch signals for the target time of 10:10 EPT. This discrepancy created a mismatch between the MW dispatch and real-time LMPs and undermined generators' incentive to follow dispatch. Under new RT SCED changes that were implemented on October 15, 2020, PJM resolved the mismatch between LPC and the RT SCED target time, but prices no longer applied at the time when resources receive and follow that dispatch signal.[62] For example, the LPC case that calculates prices for the interval ending 10:05 EPT used an approved RT SCED case that sent MW dispatch signals at 9:55 EPT which are no longer effective from 10:00 to 10:05 EPT. In the first nine months of 2021, there was still a mismatch between the MW dispatch and

Table 3-35 RT SCED cases solved, approved and used in pricing: January through September, 2020 and 2021

	2020				2021			
Month	Number of RT SCED Solutions	Number of Approved RT SCED Solutions	Number of Approved RT SCED Solutions Used in LPC	RT SCED Solutions Used in LPC as Percent of Approved RT SCED Solutions	Number of RT SCED Solutions	Number of Approved RT SCED Solutions	Number of Approved RT SCED Solutions Used in LPC	RT SCED Solutions Used in LPC as Percent of Approved RT SCED Solutions
Jan	51,022	11,860	7,612	64.2%	31,395	9,022	8,276	91.7%
Feb	46,247	10,149	7,005	69.0%	30,489	7,888	7,308	92.6%
Mar	38,680	9,914	7,799	78.7%	32,456	9,069	8,372	92.3%
Apr	36,543	8,888	7,132	80.2%	29,586	8,798	8,220	93.4%
May	36,648	9,416	7,590	80.6%	30,438	9,124	8,468	92.8%
Jun	34,327	9,165	7,666	83.6%	46,184	8,847	8,133	91.9%
Jul	30,342	9,241	8,190	88.6%	47,792	9,291	8,513	91.6%
Aug	30,775	8,962	7,868	87.8%	47,575	9,325	8,459	90.7%
Sep	30,632	8,972	7,881	87.8%	46,899	9,088	8,270	91.0%
Total	335,216	86,567	68,743	79.4%	342,814	80,452	74,019	92.0%

Figure 3-28 Daily RT SCED solutions approved for dispatch signals and solutions used in pricing: January 2020 through September 2021



62 See Docket No. ER19-2573-000.

real-time LMPs that undermined generators' incentive to follow dispatch. The timing remained incorrect until all three (the pricing interval, the dispatch interval, and the RT SCED target time) all corresponded to one another, which PJM implemented on November 1, 2021.

The extent to which dispatch instructions from approved SCED solutions are reflected in concurrent prices in the PJM Real-Time Energy Market can be measured by comparing the start and end times when the dispatch instructions from the RT SCED solution were effective with the start and end times when the corresponding prices applied. The start time for a dispatch instruction is the time at which PJM approves the RT SCED solution, which triggers sending the resulting dispatch instructions to resources. The end time for a dispatch instruction is the time when the next RT SCED solution is approved. Dispatch and pricing would be perfectly aligned if the start and end times of the dispatch instructions from an approved RT SCED solution matched with the start and end times of the LPC pricing interval that used the same RT SCED solution. In a perfectly aligned five minute market, these times would both be five minutes in duration. However, RT SCED uses a 10 minute ramp time to dispatch resources, while LPC applies prices to five minute intervals.

Table 3-36 shows the average duration of the period when dispatch instructions corresponded to the prevailing prices in the first nine months of 2021. Prior to October 15, 2020, PJM used the latest approved RT SCED solution available at the time of LPC execution, regardless of the SCED target time, to calculate prices for the current five minute pricing interval. The average duration of correspondence ranged from 3 minutes 11 seconds to 3 minutes 37 seconds from January through October 15, 2020, varying with changes to the frequency of automatic RT SCED execution. The percent of time that prices were consistent with the dispatch instructions was 67.2 to 69.9 percent, on average. This is far from the goal of 100 percent correspondence between five minute dispatch instructions and prices. With the short term changes to RT SCED that were implemented on October 15, 2020, the prices no longer corresponded to the dispatch instructions. Table 3-36 shows that during the first nine months of 2021, the dispatch instructions were consistent with prevailing prices for only 33 seconds. During this period, the percent of time that prices were consistent with the dispatch instructions was 9.0 percent. This is because by the time LMPs reflected the dispatch signals from an approved RT SCED solution, dispatchers had approved a new solution, and resources were instructed to follow new dispatch signals that did not align with the LMPs used to settle the current five minute interval. In other words, prices consistently lagged dispatch instructions by five minutes, except in cases where dispatchers had not approved a new SCED solution five minutes after a previously approved solution.

Table 3-36 Dispatch instructions reflected in prices: January through September, 2021

Period	RT SCED Automatic Execution Frequency	Dispatch Duration Reflected in Prices (Minutes:Seconds)	Percent Dispatch Duration Reflected in Prices
Jan 1, 2020 - Feb 23, 2020	Every 3 minutes	03:11	67.9%
Feb 24, 2020 - Jun 22, 2020	Every 4 minutes	03:27	67.2%
Jun 23, 2020 - Oct 14, 2020	Every 5 minutes	03:37	69.9%
Oct 15, 2020 - Dec 31, 2020	Every 5 minutes	00:39	9.9%
Jan 1, 2021 - Sep 30, 2021	Every 5 minutes	00:33	9.0%

For correct price signals and compensation, energy (LMP) and ancillary service pricing should align with the dispatch solution that is the basis for those prices and with the actual physical dispatch period during which that dispatch solution is realized for each and every real-time market interval.[63] This will only happen if RT SCED and LPC both use a five minute ramp time, consistent with the five minute real-time settlement period in PJM. The MMU recommends that PJM approve one RT SCED case for each five minute interval to dispatch resources during that interval using a five minute ramp time, and that PJM calculate prices using LPC for that five minute interval using the same approved RT SCED case. This will result in prices used to settle energy for the five minute interval that ends at the RT SCED dispatch target time.

On May 17, 2021, PJM filed tariff updates to address this issue, and proposed to update the five minute dispatch and pricing process to use a five minute ramp time beginning November 1, 2021.[64] Under this proposal, RT SCED

63 See *Settlement Intervals and Shortage Pricing in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Order No. 825, 155 FERC ¶ 61,276 (2016).
64 *See* PJM, "Enhancements to PJM Dispatch and Pricing – The 'Long-Term' Reforms," Docket No. ER21 – 1919 (May 17, 2021).

solves the real time dispatch problem using a five minute ramp time to meet load and reserve requirements at the end of each five minute interval. The RT SCED case would be approved five minutes prior to the target time, sending dispatch signals that would be effective for the same duration as modeled in the RT SCED solution. Under this proposal, LPC will use the approved RT SCED solution that sent dispatch signals for a five minute interval to calculate the prices for the same five minute interval. This proposal will ensure that the prices in any interval are consistent with the dispatch signals effective during that five minute interval, that five minute LMPs are calculated using the dispatch solution based on the five minute ramp time, and that LMPs in a five minute interval reflect the marginal offer for energy and reserves, consistent with the economic dispatch that targets the end of that five minute period.[65]

Recalculation of Five Minute Real-Time Prices

PJM's five minute interval LMPs are obtained from solved LPC cases. PJM recalculates five minute interval real-time LMPs as it believes necessary to correct errors. To do so, PJM reruns LPC cases with modified inputs. The PJM OATT allows for posting of recalculated real-time prices no later than 17:00 of the tenth calendar day following the operating day. The OATT also requires PJM to notify market participants of the underlying error no later than 17:00 of the second business day following the operating day.[66] Table 3-37 shows the number of five minute intervals in each month and number of five minute intervals in each month for which PJM recalculated real-time prices in 2020 and the first nine months of 2021. In the first nine months of 2021, PJM recalculated LMPs for 1,153 five minute intervals or 1.47 percent of the total 78,612 five minute intervals. In February 2021, PJM recalculated LMPs for several five minute intervals due to a telemetry issue that affected the calculation of regulation performance scores.

Table 3-37 Number of five minute interval real-time prices recalculated: January 2020 through September 2021

	2020		2021	
Month	Number of Five Minute Intervals	Number of Five Minute Intervals for which LMPs were recalculated	Number of Five Minute Intervals	Number of Five Minute Intervals for which LMPs were recalculated
January	8,928	193	8,928	12
February	8,352	12	8,064	496
March	8,916	110	8,916	49
April	8,640	50	8,640	266
May	8,928	37	8,928	29
June	8,640	64	8,640	22
July	8,928	67	8,928	190
August	8,928	251	8,928	58
September	8,640	20	8,640	31
October	8,928	37	-	-
November	8,652	22	-	-
December	8,928	80	-	-
Total	105,408	943	78,612	1,153

Day-Ahead Average LMP

Day-ahead, average LMP is the hourly average LMP for the PJM Day-Ahead Energy Market.[67]

PJM Day-Ahead, Average LMP

Table 3-38 shows the PJM day-ahead, average LMP for the first nine months of 2001 through 2021. The day-ahead, average LMP in the first nine months of 2021 increased 69.1 percent from the first nine months of 2020, from $19.72 per MWh to $33.34 per MWh.

65 The implementation of fast start pricing planned for September 1, 2021, will result in much more significant misalignment between price and dispatch signals.

66 OA Schedule 1 § 1.10.8(e).

67 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>.

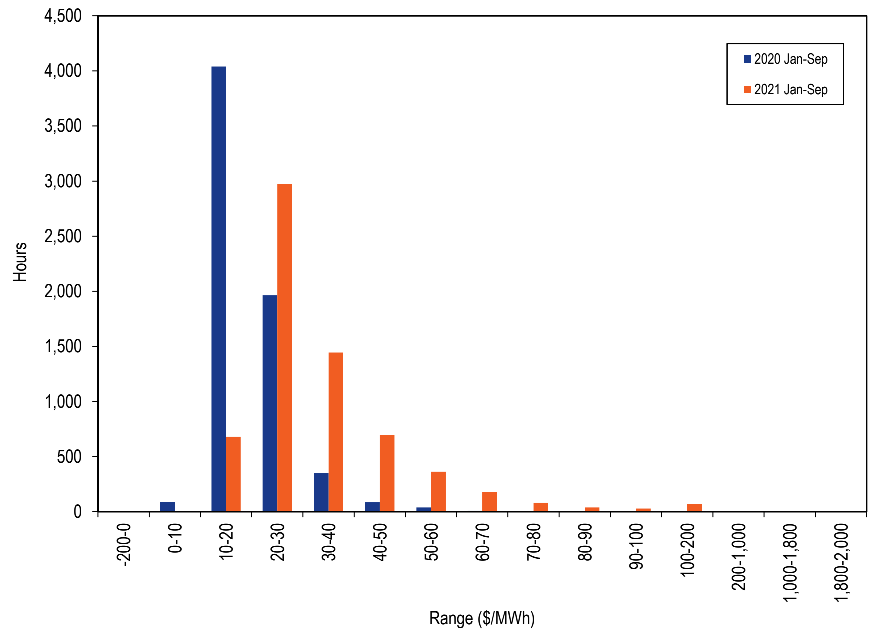
Table 3-38 Day-ahead, average LMP (Dollars per MWh): January through September, 2001 through 2021

	Day-Ahead LMP			Year to Year Change		
Jan-Sep	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2001	$36.07	$30.02	$34.25	NA	NA	NA
2002	$28.29	$22.54	$19.09	(21.6%)	(24.9%)	(44.3%)
2003	$41.20	$38.24	$22.02	45.6%	69.7%	15.4%
2004	$42.64	$42.07	$17.47	3.5%	10.0%	(20.7%)
2005	$54.48	$46.67	$28.83	27.8%	10.9%	65.1%
2006	$50.45	$46.32	$24.93	(7.4%)	(0.8%)	(13.5%)
2007	$54.24	$51.40	$24.95	7.5%	11.0%	0.1%
2008	$71.43	$66.38	$33.11	31.7%	29.2%	32.7%
2009	$37.35	$35.29	$14.32	(47.7%)	(46.8%)	(56.8%)
2010	$45.81	$41.03	$19.59	22.7%	16.3%	36.8%
2011	$45.14	$40.20	$22.68	(1.5%)	(2.0%)	15.7%
2012	$32.16	$30.10	$14.54	(28.8%)	(25.1%)	(35.9%)
2013	$37.50	$34.70	$16.96	16.6%	15.3%	16.6%
2014	$53.76	$39.92	$58.98	43.4%	15.0%	247.8%
2015	$36.67	$30.56	$25.21	(31.8%)	(23.4%)	(57.3%)
2016	$27.90	$25.23	$11.37	(23.9%)	(17.4%)	(54.9%)
2017	$28.90	$26.60	$10.73	3.6%	5.4%	(5.6%)
2018	$36.04	$29.75	$25.12	24.7%	11.8%	134.2%
2019	$26.41	$24.76	$9.58	(26.7%)	(16.8%)	(61.9%)
2020	$19.72	$18.47	$6.99	(25.3%)	(25.4%)	(27.0%)
2021	$33.34	$28.28	$16.54	69.1%	53.1%	136.7%

PJM Day-Ahead Average LMP Duration

Figure 3-29 shows the hourly distribution of PJM day-ahead, average LMP in the first nine months of 2020 and 2021.

Figure 3-29 Average LMP for the day-ahead energy market: January through September, 2020 and 2021



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 3-39 shows the PJM day-ahead, load-weighted average LMP in the first nine months of 2001 through 2021. The day-ahead, load-weighted average LMP in the first nine months of 2021 increased 69.5 percent from the first nine months of 2020, from $20.95 per MWh to $35.51 per MWh.

Table 3-39 Day-ahead, load-weighted average LMP (Dollars per MWh): January through September, 2001 through 2021

	Day-Ahead, Load-Weighted, Average LMP			Year to Year Change		
Jan-Sep	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2001	$39.88	$32.68	$42.01	NA	NA	NA
2002	$32.29	$25.22	$22.81	(19.0%)	(22.8%)	(45.7%)
2003	$44.11	$41.51	$22.34	36.6%	64.6%	(2.1%)
2004	$44.59	$44.47	$17.40	1.1%	7.1%	(22.1%)
2005	$59.51	$51.33	$31.13	33.5%	15.4%	78.9%
2006	$54.19	$48.87	$28.35	(8.9%)	(4.8%)	(8.9%)
2007	$57.79	$55.62	$26.07	6.6%	13.8%	(8.0%)
2008	$75.96	$70.35	$35.19	31.5%	26.5%	35.0%
2009	$39.35	$36.92	$14.98	(48.2%)	(47.5%)	(57.4%)
2010	$49.12	$43.33	$21.35	24.8%	17.4%	42.6%
2011	$48.34	$42.35	$26.54	(1.6%)	(2.3%)	24.3%
2012	$34.29	$31.17	$17.12	(29.1%)	(26.4%)	(35.5%)
2013	$39.49	$35.96	$19.90	15.1%	15.4%	16.3%
2014	$59.09	$42.08	$67.27	49.6%	17.0%	238.0%
2015	$39.51	$32.15	$28.05	(33.1%)	(23.6%)	(58.3%)
2016	$29.69	$26.60	$12.38	(24.8%)	(17.3%)	(55.8%)
2017	$30.26	$27.95	$11.59	1.9%	5.1%	(6.4%)
2018	$38.71	$31.62	$27.75	27.9%	13.1%	139.5%
2019	$27.70	$25.85	$10.40	(28.4%)	(18.3%)	(62.5%)
2020	$20.95	$19.23	$7.75	(24.4%)	(25.6%)	(25.4%)
2021	$35.51	$30.01	$17.97	69.5%	56.0%	131.8%

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

Figure 3-30 shows the PJM day-ahead, monthly and annual, load-weighted LMP from January 2001 through September 2021.

Figure 3-30 Day-ahead, monthly and annual, load-weighted average LMP: January 2001 through September 2021

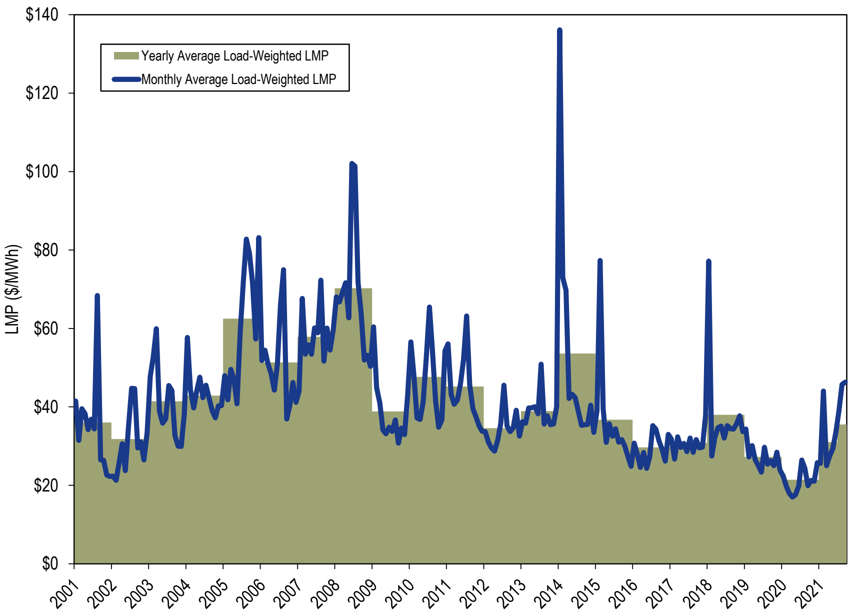
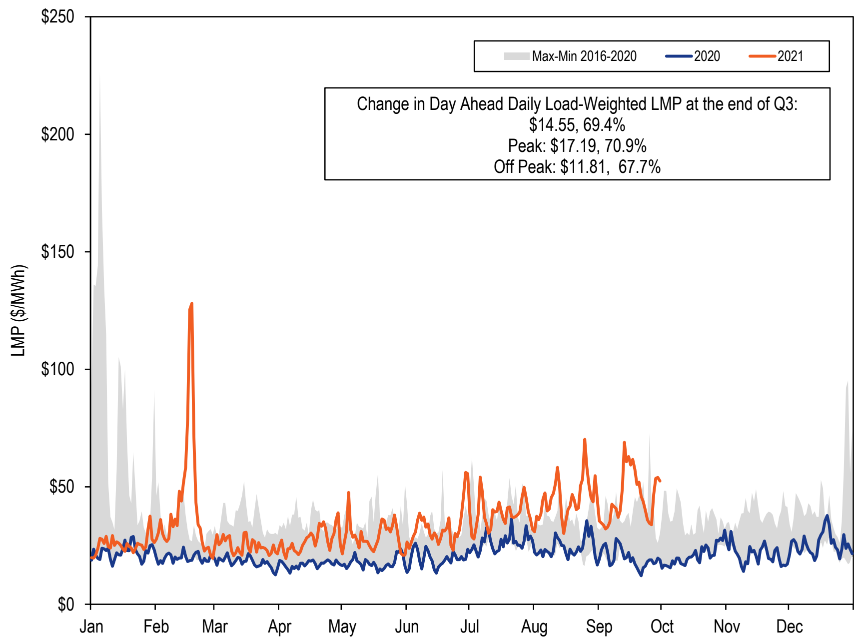


Figure 3-31 shows the PJM day-ahead daily, load-weighted LMP in 2020 through the first nine months 2021 compared to the historic five year price range.

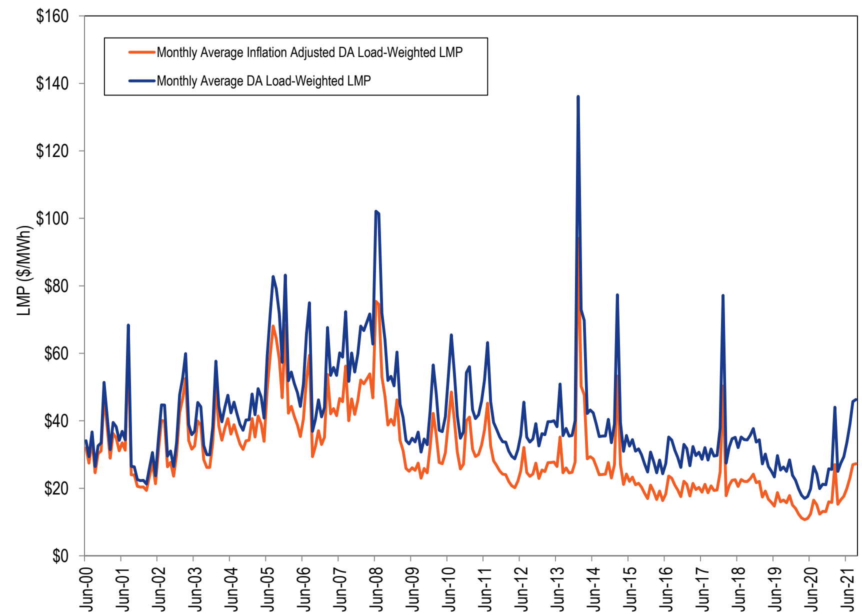
Figure 3-31 Day-ahead, daily, load-weighted average LMP: January 2020 through September 2021



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

Figure 3-32 shows the PJM day-ahead, monthly, load-weighted, average LMP and inflation adjusted monthly day-ahead, load-weighted, average LMP for June 2000 through September 2021.[68] Table 3-40 shows the PJM day-ahead, load-weighted, average LMP and inflation adjusted load-weighted, average LMP for the first nine months of every year from 2000 through 2021. The PJM day-ahead, inflation adjusted, load-weighted, average LMP for the first nine months of 2021 was the fifth lowest ($21.30 per MWh) since PJM day-ahead markets started in 2000. The day-ahead inflation adjusted monthly load-weighted, average LMP for April 2020 ($10.70 per MWh) was the lowest monthly value since the day-ahead markets started.

Figure 3-32 Day-ahead, monthly, load-weighted average LMP unadjusted and inflation adjusted: June 2000 through September 2021



68 To obtain the inflation adjusted monthly load-weighted average LMP, the PJM system-wide load-weighted average LMP is deflated using US Consumer Price Index for all items, Urban Consumers (base period: January 1998), published by *Bureau of Labor Statistics*. <http://download.bls.gov/pub/time.series/cu/cu.data.1.AllItems> (Accessed October 13, 2021).

Table 3-40 Day-ahead, yearly, load-weighted average LMP unadjusted and inflation adjusted: January through September, 2001 through 2021

	Load-Weighted, Average LMP Jan-Sep	Inflation Adjusted Load-Weighted, Average LMP Jan-Sep
2000	$31.81	$29.74
2001	$39.88	$36.41
2002	$32.29	$29.02
2003	$44.11	$38.81
2004	$44.59	$38.26
2005	$59.51	$49.32
2006	$54.19	$43.40
2007	$57.79	$45.19
2008	$75.96	$56.73
2009	$39.35	$29.77
2010	$49.12	$36.46
2011	$48.34	$34.79
2012	$34.29	$24.17
2013	$39.49	$27.40
2014	$59.09	$40.45
2015	$39.51	$26.99
2016	$29.69	$20.03
2017	$30.26	$19.99
2018	$38.71	$24.98
2019	$27.70	$17.55
2020	$20.95	$13.09
2021	$35.51	$21.30

Price Convergence

The introduction of the PJM Day-Ahead Energy Market with virtuals as part of the design created the possibility that competition, exercised through the use of virtual offers and bids, could tend to cause prices in the day-ahead and real-time energy markets to converge more than would be the case without virtuals. Convergence is not the goal of virtual trading, but it is a possible outcome.

In practice, virtuals can receive a positive revenue anytime there is a difference in prices at any location in any hour between the day-ahead and real-time energy markets. Virtual trading can only result in price convergence at a given location and market hour if the factors affecting prices at that location and hour, such as modeled contingencies, transmission constraint limits and sources of flows, are the same in both the day-ahead and real-time models.

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 receive positive revenue from the activity for that reason regardless of the volume of those transactions and without improving the efficiency of the energy market. This is termed false arbitrage.

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 uplift 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.

INCs, DECs and UTCs allow participants to benefit from price differences between the day-ahead and real-time energy market. In theory, virtual transactions receive positive revenues when they contribute to price convergence, but with false arbitrage, high revenues result with little or no price convergence. 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 receives positive revenue. 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 receives positive revenue.

The net revenue of a UTC transaction is the net of the separate revenues of the component INC and DEC. A UTC can have a net positive revenue if the positive revenue on one side of the UTC transaction exceeds the losses on the other side.

Revenues of Virtual Transactions

Table 3-41 shows, before uplift charges, the number of cleared UTC transactions, the number of cleared UTCs with positive net revenues, the number of cleared UTCs with positive revenues at their source point and the number of cleared UTCs with positive revenues at their sink point in the first nine months of 2020 and 2021. In the first nine months of 2021, 48.5 percent of all cleared UTC transactions received positive net revenues before uplift charges. Of cleared UTC transactions, 67.4 percent received positive revenues on the source side and 33.4 percent received positive revenues on the sink side, but only 7.8 percent received positive revenues on both the source and sink side.

Table 3-41 Cleared UTC count with positive revenues by source and sink point before uplift charges: January through September, 2020 and 2021[69]

(Jan-Sep)	Cleared UTCs	Positive Revenue UTCs	Positive Revenue at Source	Positive Revenue at Sink	Positive Revenue at Source and Sink	Share Positive Revenue Overall	Share Positive Revenue Source	Share Positive Revenue Sink	Share Positive Revenue Source and Sink
2020	7,465,316	2,541,895	3,164,621	1,855,456	349,263	34.0%	42.4%	24.9%	4.7%
2021	3,605,109	1,746,693	2,430,786	1,203,728	282,352	48.5%	67.4%	33.4%	7.8%

Table 3-42 shows the number of cleared INC and DEC transactions and the number of cleared transactions with positive revenues before uplift charges in the first nine months of 2020 and 2021. Of cleared INC and DEC transactions in the first nine months of 2021, 67.1 percent of INCs had positive revenues and 34.9 percent of DECs had positive revenues.

Table 3-42 Cleared INC and DEC count with positive revenues: January through September, 2020 and 2021

(Jan-Sep)	Cleared INC	Positive Revenue INC	Positive Revenue INC Share	Cleared DEC	Positive Revenue DEC	Positive Revenue DEC Share
2020	1,647,638	708,725	43.0%	2,184,367	586,363	26.8%
2021	1,597,788	1,072,271	67.1%	1,514,661	528,991	34.9%

69 Calculations exclude PJM administrative charges.

Figure 3-33 shows the total daily net revenues of UTCs with positive net revenues, with negative net revenues, and all UTCs, before uplift charges, in the first nine months of 2021.

Figure 3-33 UTC daily positive, negative, and net revenues before uplift charges: January through September, 2021[70]

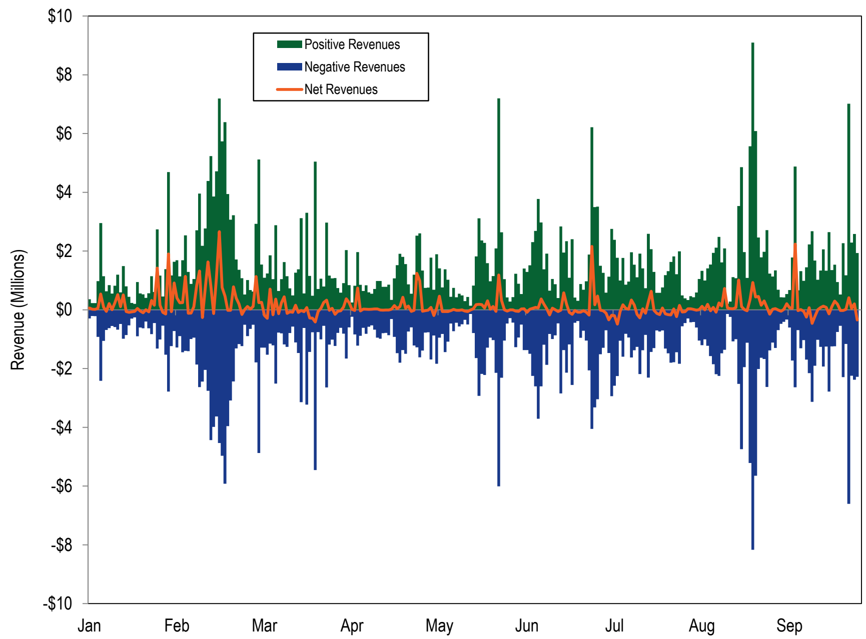


Figure 3-34 shows the cumulative UTC daily total net revenues before operating reserve charges for each year from 2013 through the first nine months of 2021.

Figure 3-34 Cumulative daily UTC net revenues before operating reserve charges: January 2013 through September 2021

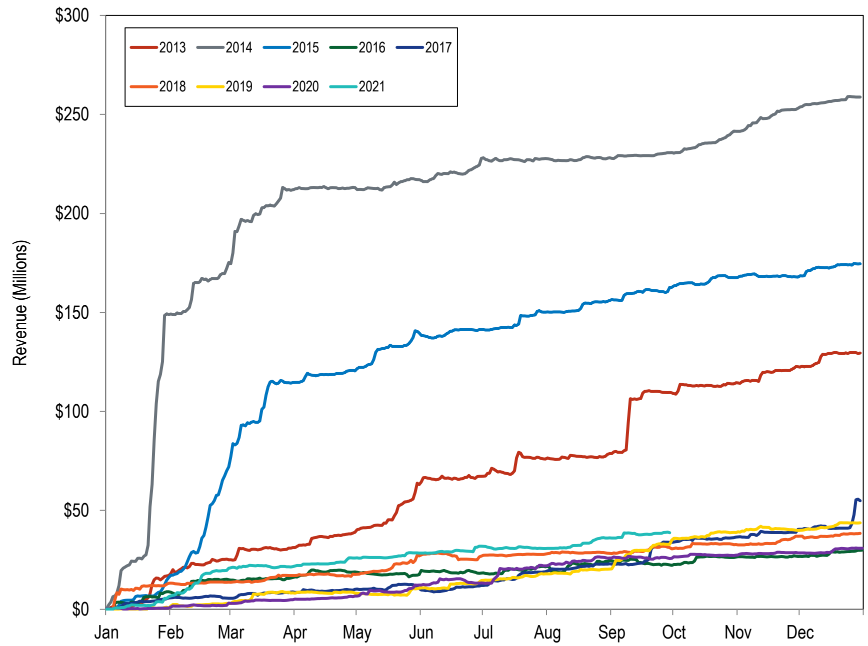


Table 3-43 shows UTC revenues before operating reserve charges by month for January 2013 through September 2021. May 2016, September 2016, February 2017, June 2018, September 2020, and July 2021 were the only months in this seven year period in which monthly net revenues were negative. Total UTC revenues before uplift charges were higher in the first nine months of 2021 than in all of 2020 despite a significantly lower volume of bid and cleared UTC MWh in 2021.

70 Calculations exclude PJM administrative charges.

Table 3-43 UTC net revenues before operating reserve charges by month: January 2013 through September 2021

	January	February	March	April	May	June	July	August	September	October	November	December	Total
2013	$17,048,654	$8,304,767	$5,629,392	$7,560,773	$25,219,947	$3,484,372	$8,781,526	$2,327,168	$31,160,618	$4,393,583	$8,730,701	$6,793,990	$129,435,490
2014	$148,973,434	$23,235,621	$39,448,716	$1,581,786	$3,851,636	$7,353,460	$3,179,356	$287,824	$2,727,763	$10,889,817	$11,042,443	$6,191,101	$258,762,955
2015	$16,132,319	$53,830,098	$44,309,656	$6,392,939	$19,793,475	$824,817	$8,879,275	$5,507,608	$6,957,012	$4,852,454	$392,876	$6,620,581	$174,493,110
2016	$8,874,363	$6,118,477	$1,119,457	$2,768,591	($1,333,563)	$841,706	$3,128,346	$3,200,573	($2,518,408)	$4,216,717	$254,684	$3,271,368	$29,942,312
2017	$5,716,757	($17,860)	$3,083,167	$944,939	$1,245,988	$868,400	$7,053,390	$4,002,063	$10,960,012	$2,360,817	$2,716,950	$15,936,217	$54,870,839
2018	$13,184,346	$506,509	$3,410,577	$688,796	$9,499,735	($768,614)	$1,163,380	$692,736	$2,845,649	$1,452,515	$4,339,363	$1,358,446	$38,373,436
2019	$574,901	$2,407,307	$5,287,985	$332,036	$1,833,879	$3,382,009	$4,066,461	$2,442,971	$12,599,278	$5,914,042	$1,171,145	$3,722,403	$43,734,418
2020	$664,972	$2,497,856	$1,720,037	$1,865,139	$5,508,276	$1,123,429	$8,573,276	$3,957,296	($141,240)	$1,628,186	$1,170,367	$2,319,727	$30,887,320
2021	$6,421,567	$13,241,294	$1,788,961	$4,529,921	$2,542,898	$3,384,291	($1,199,849)	$5,330,600	$2,649,331				$38,689,015

Figure 3-35 shows total INC and DEC daily revenues before uplift charges, gross positive revenues, the sum of all positive revenue transactions, gross negative revenues, the sum of all negative revenue transactions, and net revenues in the first nine months of 2021.

Figure 3-35 INC and DEC daily positive, negative, and total revenues before uplift charges: January through September, 2021[71]

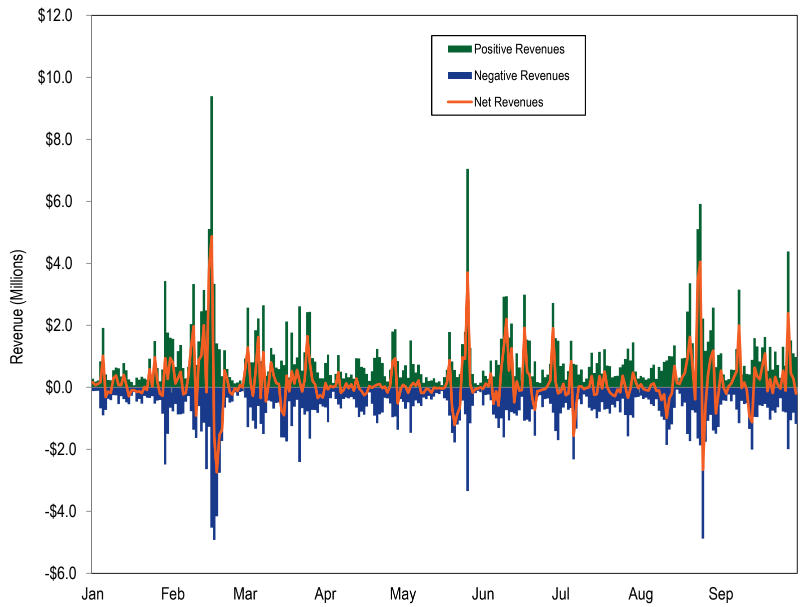
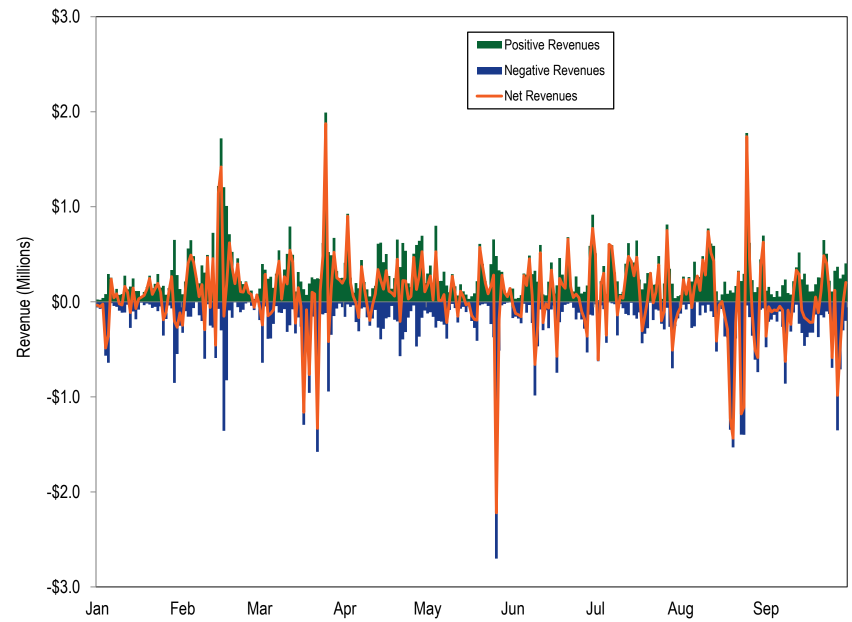


Figure 3-36 shows total INC daily gross positive and negative revenues and net revenues before uplift charges in the first nine months of 2021.

Figure 3-36 INC daily positive, negative, and total net revenues before uplift charges January through September, 2021[72]



71 Calculations exclude PJM administrative charges.

72 Calculations exclude PJM administrative charges.

Figure 3-37 shows total DEC daily gross positive and negative revenues and net revenues before uplift charges in the first nine months of 2021.

Figure 3-37 DEC daily positive, negative, and total net revenues before uplift charges: January through September, 2021[73]

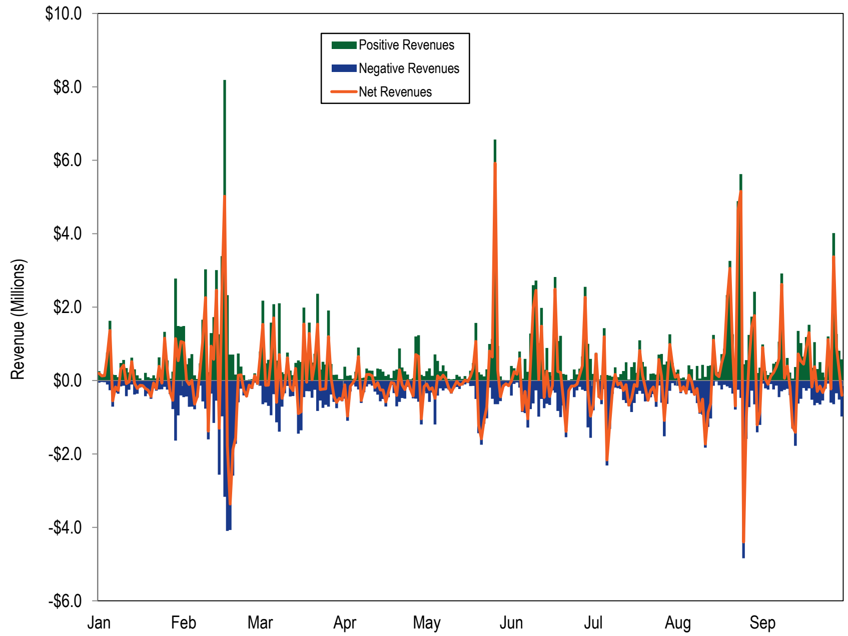
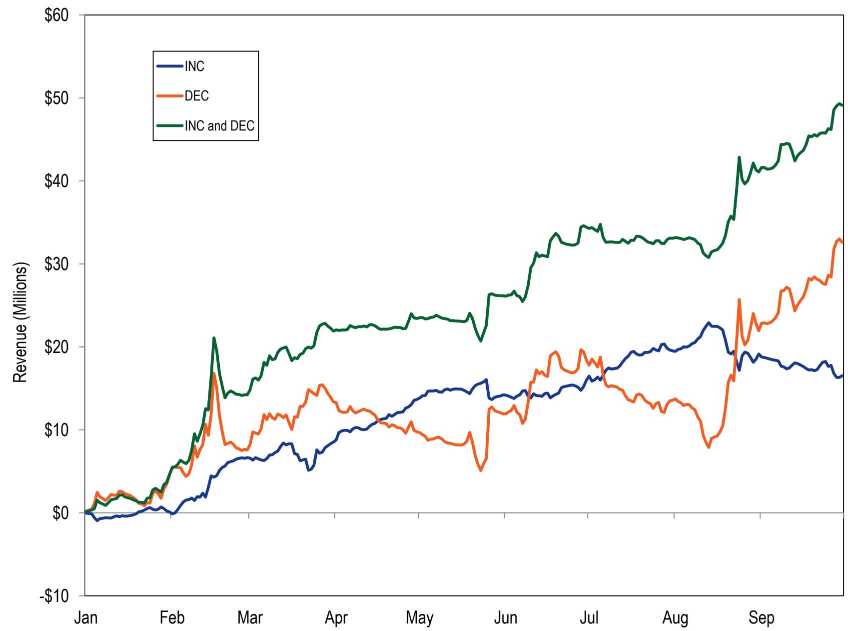


Figure 3-38 shows the cumulative INC and DEC daily revenues before uplift charges for the first nine months of 2021. The revenues of DECs increased after fast start pricing implementation on September 1, 2021.

Figure 3-38 Cumulative daily INC and DEC revenues before uplift charges: January through September, 2021



73 Calculations exclude PJM administrative charges.

Table 3-44 shows INC and DEC revenues before uplift charges by month for the first nine months of 2021.

Table 3-44 INC and DEC revenues before uplift charges by month: January through September, 2021

	January	February	March	April	May	June	July	August	September	Total
INCs	$116,313	$6,534,110	$1,874,664	$5,140,992	$554,421	$1,767,917	$3,526,962	($375,872)	($2,629,138)	$16,510,368
DECs	$4,506,985	$3,060,102	$5,820,332	($3,623,933)	$2,168,601	$6,490,068	($4,855,699)	$8,379,135	$10,656,780	$32,602,372
INCs and DECs	$4,623,297	$9,594,212	$7,694,996	$1,517,059	$2,723,022	$8,257,985	($1,328,736)	$8,003,263	$8,027,641	$49,112,740

Effect of Fast Start Pricing on Virtuals

The implementation of fast start pricing on September 1, 2021, has resulted in changes to the settlement of virtual transactions. Prior to fast start pricing, virtual products were cleared and settled based on a single set of prices. The dispatch and pricing run prices were the same. With fast start pricing, all virtual products are cleared using day-ahead dispatch run prices, but pay and receive the day-ahead and real-time pricing run prices. The use of fast start pricing has a direct impact on virtual settlements through the use of prices different from those used to dispatch virtuals. This means that a DEC may clear in the day-ahead market, based on the dispatch run, even though its offer is lower than the final, pricing run price. Likewise, an INC may clear even though its offer is higher than the day-ahead market price. The use of fast start pricing also results in divergences between day-ahead and real-time prices, which can be targeted by virtual traders. Because fast start pricing is more frequent in the real-time market, it means that, all else equal, real-time prices are higher than they otherwise would be, increasing the profitability of DECs and decreasing the profitability of INCs.

A simple way to evaluate the impact of fast start pricing on virtuals is to consider the hypothetical revenue each transaction would have received if the dispatch run prices were used for settlement, instead of the pricing run prices.

In September 2021, total INC revenue before uplift charges was -$2.63 million. Using dispatch run prices, total hypothetical INC revenue before uplift charges would have been -$0.30 million. The use of fast start pricing resulted in a decrease in revenues before uplift charges for INCs of $2.33 million, or 777 percent, compared to hypothetical revenues using dispatch run prices in September 2021.

In September 2021, total DEC revenue before uplift charges was $10.66 million. Using dispatch run prices, total hypothetical DEC revenue before uplift charges would have been $4.80 million. The use of fast start pricing resulted in an increase in revenues before uplift charges for DECs of $5.86 million, or 122 percent, compared to hypothetical revenues using dispatch run prices in September 2021.

In September 2021, total UTC revenue before uplift charges was $2.65 million. Using dispatch run prices, total hypothetical UTC revenue before uplift charges would have been $2.36 million. The use of fast start pricing resulted in an increase in revenues before uplift charges for UTCs of $0.29 million, or 12.3 percent, compared to hypothetical revenues using dispatch run prices in September 2021.

There are incentives to use virtual transactions to profit from price differences between the day-ahead and real-time energy markets, but there is no guarantee that such activity will result in price convergence and no data to support that claim. As a general matter, virtual offers and bids are based on expectations about both day-ahead and real-time energy market conditions and reflect the uncertainty about conditions in both markets, about modeling differences 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. PJM markets do not provide a mechanism that could ever result in convergence in the presence of modeling differences.

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.

Day-ahead and Real-time Prices

Table 3-45 shows that the difference between the average real-time price and the average day-ahead price.

Table 3-45 Day-ahead and real-time average LMP (Dollars per MWh): January through September, 2020 and 2021[74]

	2020				2021			
Jan-Sep	Day-Ahead	Real-Time	Difference	Percent of Real Time	Day-Ahead	Real-Time	Difference	Percent of Real Time
Average	$19.72	$19.95	$0.23	1.2%	$33.34	$33.49	$0.15	0.4%
Median	$18.47	$17.87	($0.60)	(3.4%)	$28.28	$26.82	($1.46)	(5.4%)
Standard deviation	$6.99	$10.48	$3.49	33.3%	$16.54	$24.08	$7.55	31.3%
Peak average	$23.13	$23.46	$0.32	1.4%	$39.48	$39.64	$0.16	0.4%
Peak median	$20.96	$20.10	($0.86)	(4.3%)	$33.75	$31.77	($1.98)	(6.2%)
Peak standard deviation	$7.43	$12.33	$4.90	39.8%	$19.35	$29.66	$10.32	34.8%
Off peak average	$16.69	$16.85	$0.16	0.9%	$27.98	$28.12	$0.14	0.5%
Off peak median	$15.86	$15.68	($0.18)	(1.2%)	$24.92	$24.43	($0.49)	(2.0%)
Off peak standard deviation	$4.87	$7.21	$2.34	32.5%	$11.11	$16.00	$4.88	30.5%

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.

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

Table 3-46 shows the difference between the real-time load-weighted and the day-ahead load-weighted energy market prices for the first nine months of 2001 through 2021.

Table 3-46 Day-ahead load-weighted and real-time load-weighted average LMP (Dollars per MWh): January through September, 2001 through 2021

	Load-Weighted Average LMP			
Jan-Sep	Day-Ahead	Real-Time	Difference	Percent of Real Time
2001	$36.07	$36.00	($0.07)	(0.2%)
2002	$28.29	$28.13	($0.16)	(0.6%)
2003	$41.20	$40.42	($0.77)	(1.9%)
2004	$42.64	$43.85	$1.22	2.9%
2005	$54.48	$54.69	$0.21	0.4%
2006	$50.45	$51.79	$1.34	2.7%
2007	$54.24	$57.34	$3.10	5.7%
2008	$71.43	$71.94	$0.51	0.7%
2009	$37.35	$37.42	$0.08	0.2%
2010	$45.81	$46.13	$0.32	0.7%
2011	$45.14	$45.79	$0.65	1.4%
2012	$32.16	$32.45	$0.29	0.9%
2013	$37.50	$37.30	($0.20)	(0.5%)
2014	$53.76	$52.72	($1.04)	(1.9%)
2015	$36.67	$35.96	($0.70)	(1.9%)
2016	$27.90	$27.43	($0.47)	(1.7%)
2017	$28.90	$28.79	($0.11)	(0.4%)
2018	$36.04	$36.52	$0.48	1.3%
2019	$26.41	$26.30	($0.11)	(0.4%)
2020	$19.72	$19.95	$0.23	1.2%
2021	$33.34	$33.49	$0.15	0.4%

Table 3-47 includes frequency distributions of the differences between PJM real-time, load-weighted, hourly LMP and PJM day-ahead, load-weighted, hourly LMP for the first nine months of 2020 and 2021.

Table 3-47 Frequency distribution by hours of real-time, load-weighted LMP minus day-ahead, load-weighted LMP (Dollars per MWh): January through September, 2020 and 2021

	2020 (Jan-Sep)		2021(Jan-Sep)	
LMP	Frequency	Cumulative Percent	Frequency	Cumulative Percent
< ($200)	0	0.00%	0	0.00%
($200) to ($100)	0	0.00%	0	0.00%
($100) to ($50)	0	0.18%	12	0.00%
($50) to $0	4,086	65.41%	4,273	62.14%
$0 to $50	2,467	98.64%	2,177	99.67%
$50 to $100	20	99.60%	63	99.97%
$100 to $200	2	99.86%	17	100.00%
$200 to $400	0	99.98%	8	100.00%
$400 to $800	0	100.00%	1	100.00%
>= $800	0	100.00%	0	100.00%

Figure 3-39 shows the hourly differences between day-ahead and real-time hourly LMP in the first nine months of 2021. The average difference has increased since fast start pricing was implemented on September 1, 2021.

Figure 3-39 Real-time hourly LMP minus day-ahead hourly LMP: January through September, 2021

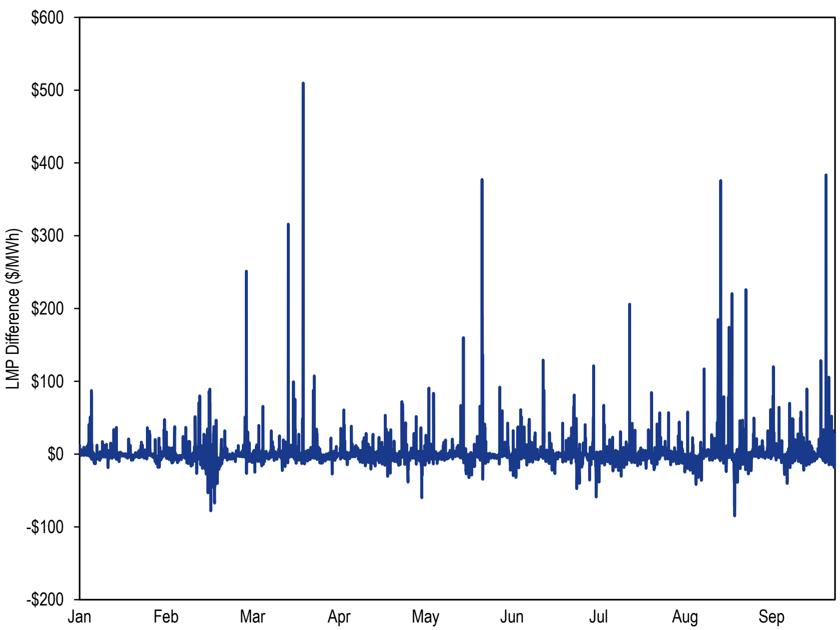
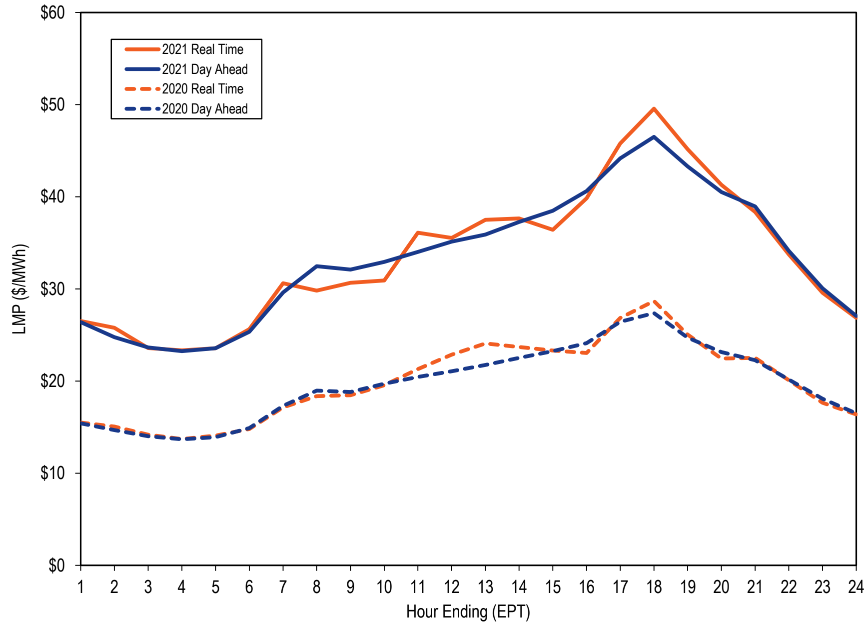


Figure 3-40 shows day-ahead and real-time, load-weighted, average hourly LMP for the first nine months of 2020 and 2021.

Figure 3-40 System hourly average LMP: January through September, 2020 and 2021



Zonal LMP and Dispatch

Table 3-48 shows zonal real-time, and real-time, load-weighted average LMP in the first nine months of 2020 and 2021.

Table 3-48 Zonal real-time and real-time, load-weighted average LMP (Dollars per MWh): January through September, 2020 and 2021

	Real-Time Average LMP			Real-Time, Load-Weighted, Average LMP		
Zone	2020 Jan-Sep	2021 Jan-Sep	Percent Change	2020 Jan-Sep	2021 Jan-Sep	Percent Change
ACEC	$17.80	$29.28	64.6%	$19.26	$32.26	67.5%
AEP	$20.53	$33.91	65.2%	$21.65	$35.70	64.9%
APS	$20.75	$33.43	61.1%	$22.01	$35.21	60.0%
ATSI	$20.94	$32.77	56.5%	$22.37	$34.76	55.4%
BGE	$22.91	$37.73	64.7%	$24.97	$40.68	62.9%
COMED	$18.50	$31.88	72.3%	$19.87	$34.49	73.6%
DAY	$21.30	$35.62	67.3%	$22.63	$38.09	68.3%
DUKE	$20.46	$34.52	68.7%	$21.71	$37.03	70.6%
DOM	$20.85	$37.07	77.8%	$22.16	$39.68	79.0%
DPL	$19.70	$34.55	75.3%	$22.17	$37.57	69.5%
DUQ	$21.12	$32.41	53.4%	$22.85	$34.57	51.3%
EKPC	$20.33	$33.75	66.0%	$21.53	$36.12	67.8%
JCPLC	$18.10	$29.16	61.2%	$19.73	$31.96	62.0%
MEC	$19.14	$32.46	69.6%	$20.65	$35.06	69.8%
OVEC	$19.89	$32.61	63.9%	$19.98	$32.71	63.7%
PECO	$17.50	$29.06	66.0%	$18.64	$31.29	67.9%
PE	$19.47	$31.36	61.1%	$20.48	$32.72	59.8%
PEPCO	$21.21	$36.30	71.1%	$22.77	$39.30	72.6%
PPL	$17.66	$30.11	70.5%	$18.63	$31.78	70.6%
PSEG	$18.03	$31.20	73.0%	$19.13	$33.53	75.2%
REC	$18.47	$33.64	82.2%	$20.05	$36.82	83.6%
PJM	$19.95	$33.49	67.9%	$21.22	$35.68	68.1%

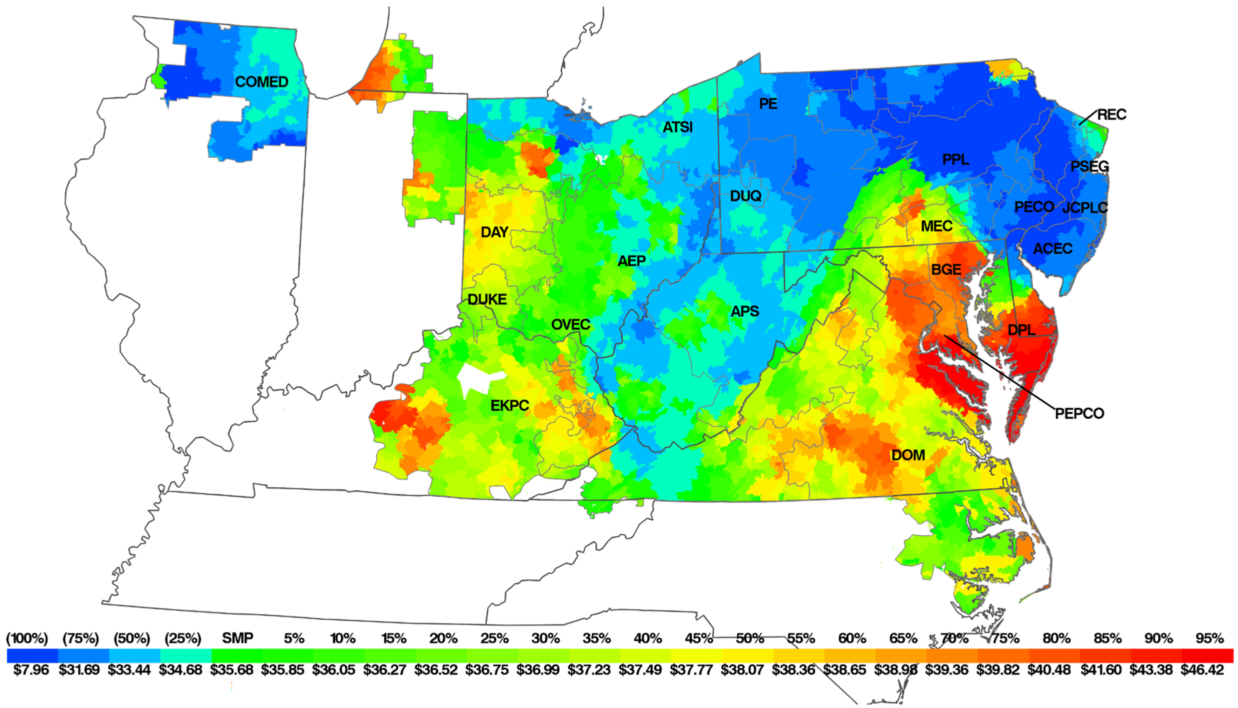
Table 3-49 shows zonal day-ahead, and day-ahead, load-weighted, average LMP in the first nine months of 2020 and 2021.

Table 3-49 Day-ahead zonal average and load-weighted average LMP (Dollars per MWh): January through September, 2020 and 2021

	Day-Ahead Average LMP			Day-Ahead, Load-Weighted, Average LMP		
Zone	2020 Jan-Sep	2021 Jan-Sep	Percent Change	2020 Jan-Sep	2021 Jan-Sep	Percent Change
ACEC	$17.50	$29.49	68.5%	$18.88	$32.26	70.9%
AEP	$20.34	$33.74	65.9%	$21.46	$35.60	65.9%
APS	$20.35	$33.47	64.4%	$21.51	$35.21	63.7%
ATSI	$20.44	$33.30	62.9%	$21.59	$35.06	62.4%
BGE	$22.75	$37.59	65.2%	$24.66	$40.42	63.9%
COMED	$18.57	$31.77	71.1%	$19.81	$34.10	72.1%
DAY	$21.30	$35.74	67.8%	$22.64	$38.21	68.8%
DUKE	$20.57	$34.79	69.2%	$21.93	$37.21	69.6%
DOM	$20.74	$36.24	74.7%	$22.13	$38.92	75.9%
DPL	$18.76	$33.17	76.8%	$20.86	$36.53	75.2%
DUQ	$20.70	$32.80	58.5%	$22.24	$34.86	56.8%
EKPC	$20.17	$33.48	66.0%	$21.67	$36.06	66.4%
JCPLC	$17.63	$29.60	67.9%	$18.96	$32.15	69.6%
MEC	$18.61	$32.50	74.7%	$19.96	$34.94	75.1%
OVEC	$19.79	$32.71	65.3%	$21.04	$35.99	71.1%
PECO	$17.28	$29.14	68.7%	$18.35	$31.18	69.9%
PE	$19.38	$32.27	66.5%	$20.70	$34.15	65.0%
PEPCO	$21.19	$36.02	70.0%	$22.83	$38.88	70.3%
PPL	$17.44	$30.28	73.6%	$18.35	$31.86	73.6%
PSEG	$17.73	$30.42	71.6%	$18.78	$32.67	73.9%
REC	$18.17	$32.41	78.3%	$19.73	$36.05	82.7%
PJM	$19.72	$33.34	69.1%	$20.95	$35.51	69.5%

Figure 3-41 is a map of the real-time, load-weighted, average LMP in the first nine months of 2021. 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.

Figure 3-41 Real-time, load-weighted average LMP: January through September, 2021



Transmission Penalty Factors

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.

Table 3-50 shows the frequency and average shadow price of transmission constraints in PJM. In the first nine months of 2021, there were 112,781 transmission constraint intervals in the real-time market with a nonzero shadow price. For nearly eight percent of these transmission constraint intervals, the line limit was violated, meaning that the flow exceeded the facility limit.[75] In the first nine months of 2021, the average shadow price of transmission constraints when the line limit was violated was nearly 11.0 times higher than when the transmission constraint was binding at its limit.

Table 3-50 Frequency and average shadow price of transmission constraints: January through September, 2020 and 2021

	Frequency (Constraint Intervals)		Average Shadow Price	
Description	2020 (Jan - Sep)	2021 (Jan - Sep)	2020 (Jan - Sep)	2021 (Jan - Sep)
PJM Internal Violated Transmission Constraints	5,383	9,338	$1,481.01	$1,866.92
PJM Internal Binding Transmission Constraints	92,535	72,667	$88.51	$167.81
Market to Market Transmission Constraints	27,575	30,776	$231.08	$442.36
All Transmission Constraints	125,493	112,781	$179.57	$383.41

Transmission penalty factors should be applied without discretion. PJM adopted the MMU's recommendation to remove the constraint relaxation logic and allow transmission penalty factors to set prices in the day-ahead and real-time markets for all internal transmission constraints. PJM also revised the tariff to list the conditions under which transmission penalty factors would be changed from their default value of $2,000 per MWh. The new rules went into effect on February 1, 2019. The Commission approved the PJM and MISO joint filing to remove the constraint relaxation logic for market to market constraints on March 6, 2020. PJM and MISO implemented the changes to their dispatch software in the second half of 2020.

PJM continues the practice of discretionary reductions in line ratings. Table 3-51 shows the frequency of changes to the transmission constraints for binding and violated transmission constraints in the PJM real-time market. In the first nine months of 2021, there were 9,117 or 98 percent of 9,338 internal violated transmission constraint intervals in the real-time market with constraint limit less than 100 percent of the actual constraint limit. In the first nine months of 2021, among the constraints with reduced constraint limits, the constraint limit was reduced on average by 6.5 percent.

Table 3-51 Frequency of reduction in line ratings (constraint intervals): January through September, 2020 and 2021

	Frequency (Constraint Intervals)		Constraints with Reduced Line Limits (Constraint Intervals)		Average Reduction (Percentage)	
Description	2020 (Jan - Sep)	2021 (Jan - Sep)	2020 (Jan - Sep)	2021 (Jan - Sep)	2020 (Jan - Sep)	2021 (Jan - Sep)
PJM Internal Violated Transmission Constraints	5,383	9,338	4,912	9,117	7.5%	6.5%
PJM Internal Binding Transmission Constraints	92,535	72,667	90,734	71,908	9.5%	7.1%
Market to Market Transmission Constraints	27,575	30,776	6,528	11,764	6.6%	5.6%
All Transmission Constraints	125,493	112,781	102,174	92,789	9.2%	6.9%

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

Table 3-52 shows the frequency of changes to the magnitude of transmission penalty factors for binding and violated transmission constraints in the PJM Real-Time Energy Market. In the first nine months of 2021, there were 8,190 or 88 percent of internal violated transmission constraint intervals in the real-time market with a transmission penalty factor equal to the default $2,000 per MWh.

Table 3-52 Frequency of changes to the magnitude of transmission penalty factor (constraint intervals): January through September, 2020 and 2021

	2020 (Jan - Sep)			2021 (Jan - Sep)		
Description	$2,000 per MWh (Default)	Above $2,000 per MWh	Below $2,000 per MWh	$2,000 per MWh (Default)	Above $2,000 per MWh	Below $2,000 per MWh
PJM Internal Violated Transmission Constraints	3,384	88	1,911	8,190	190	958
PJM Internal Binding Transmission Constraints	84,544	155	7,836	71,367	26	1,274
Market to Market Transmission Constraints	2,195	-	25,380	4,623	-	26,153
All Transmission Constraints	90,123	243	35,127	84,180	216	28,385

Transmission constraint penalty factors frequently set prices when PJM models a surrogate constraint to limit the dispatch of a generator that would experience voltage instability at its full output due to a transmission outage. Changes to the surrogate constraint limit that exceed the unit's ability to reduce output cause constraint violations. Constraint violations also occur when the unit follows the regulation signal or increases its minimum operating parameters above the surrogate constraint limit. Prices set at the $2,000 per MWh penalty factor are not useful signals to the market under these conditions and create false arbitrage opportunities for virtuals.

PJM used CT pricing logic until the implementation of fast start pricing on September 1, 2021, to force otherwise uneconomic resources to be marginal and set price in the day-ahead and real-time market solutions. In the event PJM committed a resource that is uneconomic and/or offered with inflexible parameters, PJM used CT pricing logic to model a constraint with a variable flow limit, paired with an artificial override of the inflexible resource's economic minimum, to force the resource to be marginal in the PJM market solution.[76] Frequently, PJM dispatchers also manually overrode the transmission violation penalty factor of the constraint to match the offer price of the resource to artificially control the shadow price of the constraint. Table 3-53 shows the frequency of CT pricing logic used in the PJM Real-Time Energy Market. In the first nine months of 2021, there were 9,073 constraint intervals in the real-time market where CT pricing logic was used. In the PJM CT pricing logic, there could be one or multiple resources paired with a constraint.

PJM's use of CT pricing logic was inconsistent with the efficient market dispatch and pricing. For that reason, in 2019 FERC declared CT pricing logic to be unjust and unreasonable.[77]

76 PJM dispatchers generally log the resources paired with a constraint in the CT pricing logic. The data presented is based on PJM dispatcher logs.
77 167 FERC ¶ 61,058 at P 69 (2019).

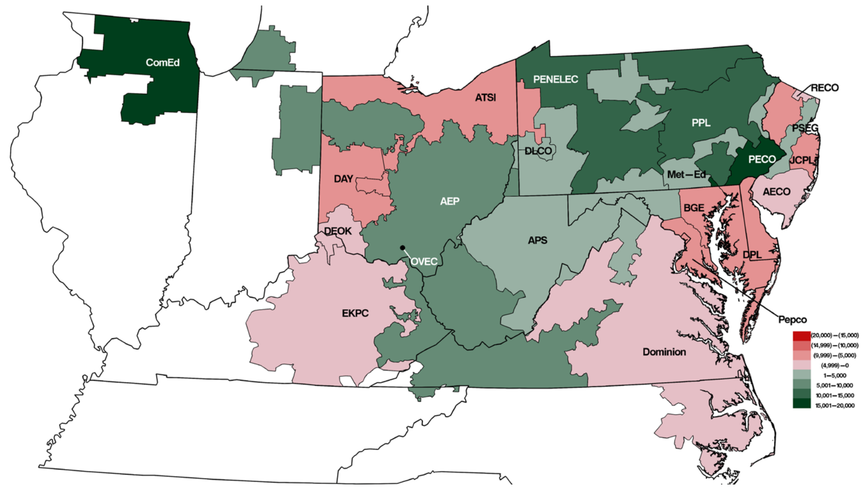
Table 3-53 Frequency of CT pricing logic used in the real-time market (constraint intervals): January 2020 through September 2021

Month	2020	2021
Jan	231	783
Feb	167	469
Mar	122	1,186
Apr	173	1,539
May	632	1,204
Jun	825	1,240
Jul	842	1,102
Aug	1,189	1,550
Sep	1,982	0
Oct	2,017	
Nov	956	
Dec	1,404	
Total	10,540	9,073

Net Generation by Zone

Figure 3-42 shows the difference between the PJM real-time generation and real-time load by zone in the first nine months of 2021. Figure 3-42 is color coded using 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. Table 3-54 shows the difference between the PJM real-time generation and real-time load by zone in the first nine months of 2020 and 2021.

Figure 3-42 Map of real-time generation less real-time load by zone: January through September, 2021[78]



78 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 3-54 Real-time generation less real-time load by zone (GWh): January through September, 2020 and 2021

Zonal Generation and Load (GWh)						
Jan-Sep	2020			2021		
Zone	Generation	Load	Net	Generation	Load	Net
ACEC	2,927.2	7,349.9	(4,422.7)	2,252.1	7,684.0	(5,431.9)
AEP	103,165.6	90,941.6	12,224.0	109,476.0	94,442.4	15,033.6
APS	36,509.9	35,358.0	1,151.9	41,171.8	36,363.4	4,808.4
ATSI	33,957.4	47,350.2	(13,392.8)	37,475.5	49,042.4	(11,566.9)
BGE	12,275.1	22,688.8	(10,413.7)	13,858.0	23,435.2	(9,577.2)
COMED	96,705.0	69,523.7	27,181.3	99,058.1	71,319.7	27,738.4
DAY	760.9	12,416.0	(11,655.1)	808.5	12,828.8	(12,020.3)
DUKE	13,686.1	19,433.7	(5,747.6)	13,108.1	20,037.7	(6,929.6)
DOM	82,005.0	74,742.5	7,262.5	75,661.2	80,911.6	(5,250.4)
DPL	4,352.6	13,563.6	(9,211.0)	3,376.5	14,156.6	(10,780.1)
DUQ	11,753.0	9,852.0	1,901.0	12,523.3	9,962.6	2,560.7
EKPC	6,267.9	9,235.7	(2,967.8)	8,416.2	9,746.3	(1,330.2)
JCPLC	6,811.0	16,573.5	(9,762.5)	5,551.3	17,077.2	(11,525.9)
MEC	15,674.6	11,368.0	4,306.6	13,961.1	11,726.1	2,235.0
OVEC	6,438.6	83.4	6,355.2	8,418.6	85.7	8,333.0
PECO	56,344.3	28,667.0	27,677.3	54,942.1	29,603.6	25,338.4
PE	28,158.2	12,366.5	15,791.7	33,157.5	12,539.5	20,617.9
PEPCO	8,901.6	20,765.2	(11,863.5)	9,303.2	21,402.0	(12,098.8)
PPL	46,712.3	29,618.3	17,093.9	52,093.7	30,470.4	21,623.3
PSEG	32,982.8	31,729.9	1,252.9	32,923.8	32,482.2	441.6
RECO	0.0	1,072.0	(1,072.0)	0.0	1,097.9	(1,097.9)

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 intervals 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 intervals 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.

Fuel Prices, LMP, and Dispatch

Energy Production by Fuel Source

Table 3-55 shows PJM generation by fuel source in GWh for the first nine months of 2020 and 2021. In the first nine months of 2021, generation from coal units increased 30.9 percent, generation from natural gas units decreased 6.4 percent, and generation from oil increased 12.4 percent compared to the first nine months of 2020. Wind and solar output rose by 19.9 percent compared to the first nine months of 2020, supplying 4.0 percent of PJM energy in the first nine months of 2021.

Table 3-55 Generation (By fuel source (GWh)): January through September, 2020 and 2021[79 80 81]

	2020 (Jan - Sep)		2021 (Jan - Sep)		Change in
	GWh	Percent	GWh	Percent	Output
Coal	116,573.7	19.0%	152,586.7	24.0%	30.9%
Bituminous	106,220.5	17.3%	135,535.3	21.3%	27.6%
Sub Bituminous	6,484.5	1.1%	12,490.2	2.0%	92.6%
Other Coal	3,868.7	0.6%	4,561.1	0.7%	17.9%
Nuclear	207,426.7	33.7%	204,164.2	32.1%	(1.6%)
Gas	251,392.2	40.9%	235,271.3	37.0%	(6.4%)
Natural Gas CC	229,053.6	37.2%	216,176.9	34.0%	(5.6%)
Natural Gas CT	14,787.4	2.4%	14,719.6	2.3%	(0.5%)
Natural Gas Other Units	6,043.2	1.0%	3,057.3	0.5%	(49.4%)
Other Gas	1,508.0	0.2%	1,317.5	0.2%	(12.6%)
Hydroelectric	12,948.4	2.1%	13,069.5	2.1%	0.9%
Pumped Storage	3,944.5	0.6%	4,053.6	0.6%	2.8%
Run of River	7,819.9	1.3%	7,957.0	1.3%	1.8%
Other Hydro	1,184.0	0.2%	1,058.9	0.2%	(10.6%)
Wind	17,990.2	2.9%	19,862.2	3.1%	10.4%
Waste	3,298.2	0.5%	3,335.9	0.5%	1.1%
Oil	1,579.4	0.3%	1,775.1	0.3%	12.4%
Heavy Oil	73.0	0.0%	61.7	0.0%	(15.6%)
Light Oil	225.3	0.0%	462.7	0.1%	105.3%
Diesel	23.9	0.0%	24.6	0.0%	3.0%
Other Oil	1,257.1	0.2%	1,226.2	0.2%	(2.5%)
Solar, Net Energy Metering	3,007.0	0.5%	5,316.9	0.8%	76.8%
Battery	27.0	0.0%	28.5	0.0%	5.8%
Biofuel	721.0	0.1%	927.6	0.1%	28.7%
Total	614,963.9	100.0%	636,337.8	100.0%	3.5%

79 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, power to run pumped hydro pumps or power to charge batteries.
80 Net Energy Metering is combined with Solar due to data confidentiality reasons.
81 Other Gas includes: Landfill, Propane, Butane, Hydrogen, Gasified Coal, and Refinery Gas. Other Coal includes: Lignite, Liquefied Coal, Gasified Coal, and Waste Coal. Other oil includes: Gasoline, Jet Oil, Kerosene, and Petroleum-Other.

Table 3-56 Monthly generation (By fuel source (GWh)): January through September, 2021

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
Coal	17,819.0	21,469.5	13,310.1	11,172.7	12,362.1	18,648.7	22,063.1	21,631.5	14,109.9	152,586.7
Bituminous	16,369.6	18,774.2	12,427.5	10,305.2	10,666.7	16,171.8	19,254.9	18,965.2	12,600.2	135,535.3
Sub Bituminous	901.4	2,124.5	312.7	610.2	1,239.6	1,973.5	2,210.7	2,084.5	1,033.1	12,490.2
Other Coal	548.0	570.7	570.0	257.3	455.9	503.4	597.4	581.9	476.6	4,561.1
Nuclear	25,133.4	22,125.3	21,217.1	19,692.2	21,841.2	23,374.4	23,641.8	24,278.8	22,860.1	204,164.2
Gas	26,011.3	22,670.8	23,925.8	21,904.3	22,545.8	27,745.0	31,466.8	33,188.4	25,813.1	235,271.3
Natural Gas CC	25,125.8	21,754.8	23,076.4	20,077.2	20,964.3	24,758.6	27,853.9	28,767.1	23,798.7	216,176.9
Natural Gas CT	616.1	579.9	569.5	1,465.1	1,131.2	2,333.8	2,881.6	3,703.3	1,439.1	14,719.6
Natural Gas Other Units	108.9	198.0	120.1	221.1	296.3	511.5	590.7	573.1	437.6	3,057.3
Other Gas	160.6	138.1	159.8	140.8	154.0	141.0	140.6	145.0	137.6	1,317.5
Hydroelectric	1,481.8	1,299.8	1,682.6	1,317.5	1,295.9	1,313.5	1,594.6	1,509.5	1,574.4	13,069.5
Pumped Storage	398.4	354.0	311.9	244.7	357.1	539.8	637.4	665.8	544.6	4,053.6
Run of River	994.9	847.5	1,282.8	1,004.4	865.0	618.6	775.5	669.0	899.3	7,957.0
Other Hydro	88.5	98.3	87.9	68.4	73.8	155.1	181.7	174.7	130.5	1,058.9
Wind	2,507.3	2,618.9	3,445.2	2,746.0	2,187.5	1,776.5	1,175.0	1,177.2	2,228.7	19,862.2
Waste	386.1	316.6	391.6	369.1	389.6	388.0	386.4	374.8	333.5	3,335.9
Oil	159.7	254.1	151.5	166.4	205.6	200.0	199.8	277.0	161.2	1,775.1
Heavy Oil	0.0	0.0	0.3	0.0	0.0	0.0	15.9	41.0	4.4	61.7
Light Oil	7.0	136.5	23.2	12.2	51.2	89.9	44.5	92.9	5.4	462.7
Diesel	1.4	2.8	1.2	3.6	0.2	4.0	5.4	5.0	0.9	24.6
Other Oil	151.4	114.8	126.8	150.6	154.1	106.1	134.0	138.0	150.5	1,226.2
Solar, Net Energy Metering	283.1	255.8	532.7	649.8	737.6	724.6	772.6	699.7	661.1	5,316.9
Battery	2.7	3.3	3.2	4.0	3.7	3.0	3.3	2.7	2.6	28.5
Biofuel	97.4	81.4	63.7	72.1	131.6	119.6	129.2	123.1	109.5	927.6
Total	73,881.8	71,095.4	64,723.4	58,094.1	61,700.6	74,293.3	81,432.5	83,262.7	67,853.9	636,337.8

Table 3-57 shows generation by natural gas, coal, nuclear and other fuel types in the real-time energy market since 2008.

Table 3-57 Share of generation by fuel source: January through September, 2008 through 2021

Jan - Sep	Natural Gas	Coal	Nuclear	Other Fuel Type
2008	7.7%	55.0%	34.3%	3.0%
2009	10.7%	50.0%	35.8%	3.6%
2010	11.4%	50.0%	34.3%	4.3%
2011	13.8%	48.2%	33.8%	4.2%
2012	19.7%	41.7%	34.1%	4.5%
2013	16.9%	44.3%	34.5%	4.3%
2014	17.6%	44.2%	33.7%	4.4%
2015	22.6%	38.1%	34.3%	5.0%
2016	27.1%	33.8%	33.9%	5.1%
2017	26.8%	32.2%	35.3%	5.7%
2018	30.7%	29.2%	33.8%	6.4%
2019	36.0%	24.5%	33.2%	6.3%
2020	40.6%	19.0%	33.7%	6.7%
2021	36.8%	24.0%	32.1%	7.2%

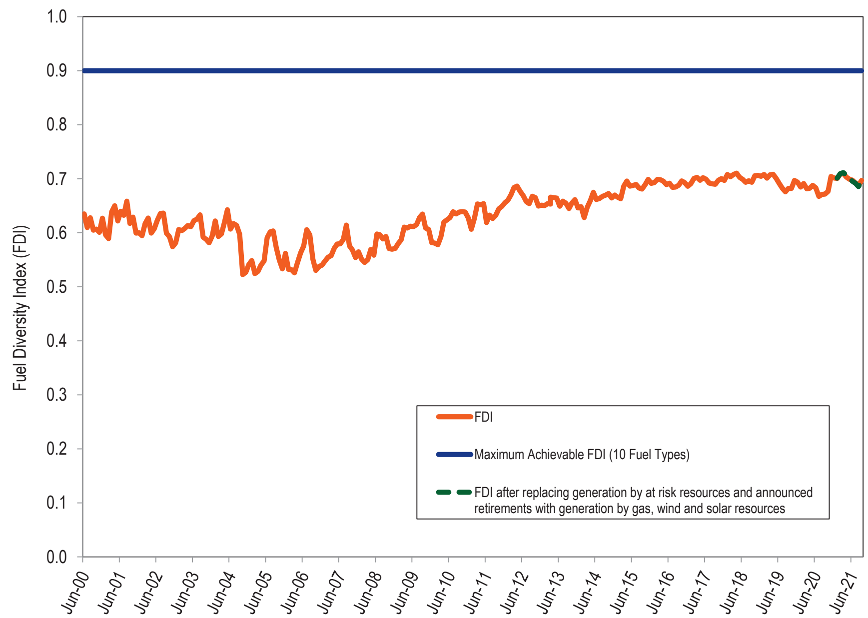
Fuel Diversity

Figure 3-43 shows the fuel diversity index (FDI_e) for PJM energy generation.[82] The FDI_e is defined as $1-\sum_{i=1}^{N} s_i^2$, where s_i is the share of fuel type i. The minimum possible value for the FDI_e is zero, corresponding to all generation from a single fuel type. The maximum possible value for the FDI_e results when each fuel type has an equal share of total generation. For a generation fleet composed of 10 fuel types, the maximum achievable index is 0.9. The fuel type categories used in the calculation of the FDI_e are the 10 primary fuel sources in Table 3-56 with nonzero generation values. As fuel diversity has increased, seasonality in the FDI_e has decreased and the FDI_e has exhibited less volatility. Since 2012, the monthly FDI_e has been less volatile as a result of the decline in the share of coal from 51.3 percent prior to 2012 to 31.8 percent from 2012 through September 30, 2021. A significant drop in the FDI_e occurred in the fall of 2004 as a result of the expansion of the PJM market footprint into ComEd, AEP, and Dayton Power & Light Control Zones and the increased shares of coal and nuclear that resulted.[83] The increasing trend that began in 2008 is a result of decreasing coal generation, increasing gas generation and increasing wind generation. Coal generation as a share of total generation was 55.0 percent for the first nine months of 2008 and 24.0 percent for the first nine months of 2021. Gas generation as a share of total generation was 7.7 percent for the first nine months of 2008 and 37.0 percent for the first nine months of 2021. Wind generation as a share of total generation was 0.4 percent for the first nine months of 2008 and 3.1 percent for the first nine months of 2021.

The FDI_e increased 2.9 percent for the first nine months of 2021 compared to first nine months of 2020. The increase in FDI_e is primarily due to an increase in coal generation in the first nine months of 2021 compared to the first nine months of 2020.

The FDI_e was also used to measure the impact on fuel diversity of potential retirements. A total of 4,763 MW of coal, CT, and other capacity were identified as being at risk of retirement.[84] Generation owners that intend to retire a generator are required by the tariff to notify PJM at least 90 days in advance.[85] There are 7,577.1 MW of generation that have requested retirement after September 30, 2021.[86] The at risk units and other generators with deactivation notices generated 15,118.5 GWh in the first nine months of 2021. The dashed line in Figure 3-43 shows a counterfactual result for FDI_e assuming the 15,118.5 GWh of generation from at risk units and other generators with deactivation notices were replaced by gas, wind and solar generation.[87] The FDI_e for the first nine months of 2021 under the counterfactual assumption would have been 0.03 percent lower than the actual FDI_e.

Figure 3-43 Fuel diversity index for monthly generation: June 2000 through September 2021



82 Monitoring Analytics developed the FDI to provide an objective metric of fuel diversity. The FDI metric is similar to the HHI used to measure market concentration. The FDI is calculated separately for energy output and for installed capacity.
83 See the *2019 State of the Market Report for PJM*, Volume 2, Appendix A, "PJM Geography" for an explanation of the expansion of the PJM footprint. The integration of the ComEd Control Area occurred in May 2004 and the integration of the AEP and Dayton control zones occurred in October 2004.
84 See Table 7-47 in the *2020 State of the Market Report for PJM*, Volume 2, Section 7: Net Revenue.
85 See PJM. OATT: § V "Generation Deactivation."
86 See *2021 State of the Market Report for PJM: January through September*, Section 12: Generation and Transmission Planning, Table 12-11.
87 It is assumed that 5,794.6 GWh of the replacement energy is from new wind and solar units. This value represents the increase over 2021 levels in renewable generation through September 30, 2021 that is required by RPS in the first nine months of 2022. The split between solar and wind, 4,653.9 GWh solar and 1,140.7 GWh wind, is based on queue data.

Natural Gas Supply Issues

A combination of pipeline transportation and natural gas supplies is needed to deliver natural gas to power plants. A generator could purchase a delivered service in which the seller bundles both the transportation and fuel to make deliveries to the plant. The delivered service could be purchased on either a term contract or a spot basis. A generator could secure pipeline transportation for part or all of the supplies needed to run the plant and purchase commodity natural gas separately with a term supply contract or through daily purchases in the spot market. Other options are also possible.

The increase in natural gas fired capacity in PJM has highlighted issues with the dependence of the PJM system reliability on the fuel transportation arrangements entered into by generators. The risks to the fuel supply for gas generators, including the risk of interruptible supply on cold days and the ability to get gas on short notice during times of critical pipeline operations, creates risks for the bulk power system. PJM should collect data on each individual generator's fuel supply arrangements, and analyze the associated locational and regional risks to reliability.

In 2020 and the first nine months of 2021, a number of interstate gas pipelines that supply fuel for generators in the PJM service territory issued restriction notices limiting the availability of nonfirm transportation services. These notices include warnings of operational flow orders (OFO) and actual OFOs. These notices may, depending on the nature of the transportation service purchased, permit the pipelines to restrict the provision of gas to 24 hour ratable takes which means that hourly nominations must be the same for each of the 24 hours in the gas day, with penalties for deviating from the nominated quantities. Pipelines may also enforce strict balancing constraints which limit the ability of gas users, depending on the nature of the transportation service purchased, to deviate from the 24 hour ratable take and which may limit the ability of users to have access to unused gas.

Pipeline operators use restrictive and inflexible rules to manage the balance of supply and demand during constrained operating conditions determined by the pipeline. 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 demonstrates the potential benefits to creating a separate gas ISO/RTO structure to coordinate the supply of gas across pipelines and with the electric RTOs and to facilitate the interoperability of the pipelines in an explicit network.

Types 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 3-58 shows the type of fuel used and technology by marginal resources in the real-time energy market. There can be more than one marginal resource in any given interval as a result of transmission constraints. In the first nine months of 2021, coal units were 16.9 percent and natural gas units were 71.0 percent of marginal resources. In the first nine months of 2021, natural gas combined cycle units were 60.9 percent of marginal resources. In the first nine months of 2020, coal units were 17.3 percent and natural gas units were 73.9 percent of the total marginal resources. In the first nine months of 2020, natural gas combined cycle units were 66.0 percent of the total marginal resources. In the first nine months of 2021, 77.8 percent of the wind marginal units had negative offer prices, 20.8 percent had zero offer prices and 1.4 percent of the wind marginal units had positive offer prices. In the first nine months of 2020, 93.6 percent of the wind marginal units had negative offer prices, 6.4 percent had zero offer prices and none had positive offer prices.

The proportion of marginal nuclear units decreased from 1.46 percent in the first nine months of 2020 to 0.81 percent in the first nine months of 2021.

Most nuclear units are offered as fixed generation in the PJM market. A small number of nuclear units were offered with a dispatchable range since 2015. The dispatchable nuclear units do not always respond to dispatch instructions.

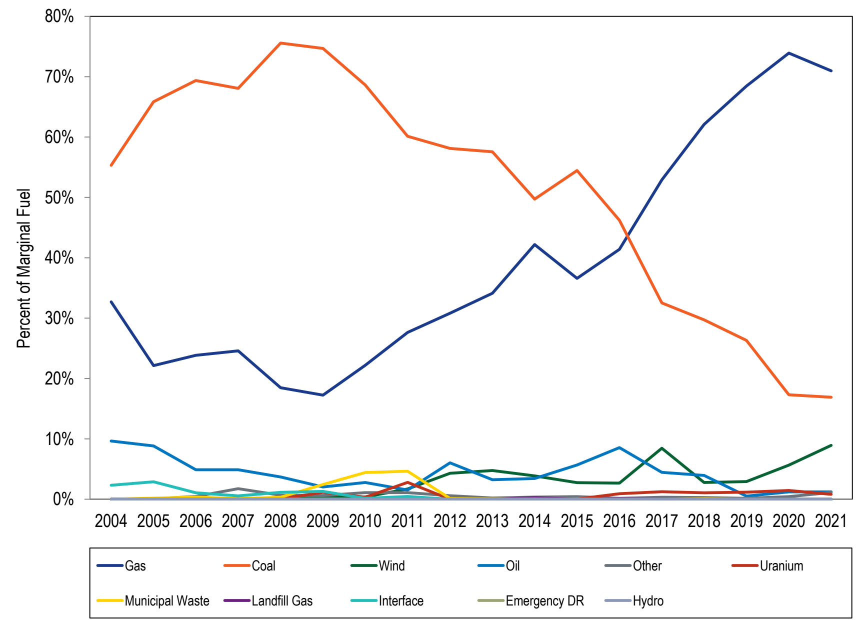
PJM implemented fast start pricing on September 1, 2021. Starting with September 1, 2021, the marginal resources shown in Table 3-58 are from the pricing run, which may not be same as marginal resources from the dispatch run.

Table 3-58 Type of fuel used and technology (By real-time marginal units): January through September, 2017 through 2021[88]

		(Jan - Sep)				
Fuel	Technology	2017	2018	2019	2020	2021
Gas	CC	44.83%	52.58%	60.79%	66.03%	60.86%
Coal	Steam	32.53%	29.71%	26.32%	17.30%	16.90%
Wind	Wind	8.44%	2.78%	2.92%	5.64%	8.93%
Gas	CT	4.55%	7.19%	6.38%	5.74%	8.52%
Gas	Steam	3.19%	1.91%	1.28%	1.84%	1.07%
Oil	CT	4.11%	2.88%	0.47%	1.11%	1.06%
Other	Solar	0.15%	0.09%	0.08%	0.40%	1.04%
Uranium	Steam	1.25%	1.06%	1.17%	1.46%	0.81%
Gas	RICE	0.34%	0.42%	0.00%	0.30%	0.53%
Other	Steam	0.18%	0.19%	0.07%	0.04%	0.10%
Oil	Steam	0.02%	0.39%	0.03%	0.07%	0.09%
Oil	RICE	0.32%	0.52%	0.00%	0.03%	0.05%
Oil	CC	0.00%	0.17%	0.02%	0.00%	0.03%
Municipal Waste	Steam	0.02%	0.04%	0.02%	0.01%	0.01%
Landfill Gas	CT	0.00%	0.00%	0.01%	0.01%	0.01%
Municipal Waste	RICE	0.00%	0.04%	0.00%	0.00%	0.00%
Municipal Waste	CT	0.00%	0.02%	0.00%	0.00%	0.00%
Landfill Gas	Steam	0.03%	0.00%	0.00%	0.00%	0.00%
Gas	Fuel Cell	0.01%	0.00%	0.00%	0.00%	0.00%
Landfill Gas	RICE	0.02%	0.00%	0.00%	0.00%	0.00%

Figure 3-44 shows the type of fuel used by marginal resources in the real-time energy market since 2004. The role of coal as a marginal resource has declined while the role of gas as a marginal resource has increased.

Figure 3-44 Type of fuel used (By real-time marginal units): January through September, 2004 through 2021



88 The unit type RICE refers to Reciprocating Internal Combustion Engines.

Table 3-59 shows the type of fuel and technology by fast start marginal resources and other marginal resources in the real-time energy market in September 2021. In the first month of the fast start pricing implementation, marginal fast start resources accounted for 6.5 percent of all marginal resources in the pricing run.

Table 3-59 Fuel type and technology (Real-time marginal units and fast start marginal units): September, 2021

		September 2021	
Fuel	Technology	Fast Start	Other
Coal	Steam	0.00%	8.95%
Gas	CC	0.00%	70.02%
Gas	CT	5.46%	4.41%
Gas	RICE	0.98%	0.38%
Gas	Steam	0.00%	2.34%
Landfill Gas	CT	0.00%	0.01%
Municipal Waste	Steam	0.00%	0.01%
Oil	CT	0.01%	0.87%
Other	Solar	0.00%	0.87%
Other	Steam	0.00%	0.02%
Uranium	Steam	0.00%	1.83%
Wind	Wind	0.02%	3.82%

Table 3-60 shows the fuel and technology used and technology where relevant, of marginal resources in the day-ahead energy market. In the first nine months of 2021, up to congestion transactions were 36.1 percent of marginal resources. Up to congestion transactions were 53.8 percent of marginal resources in the first nine months of 2020. In the first nine months of 2021, virtual transactions were 79.9 percent of marginal resources. Virtual transactions were 83.9 percent of marginal resources in the first nine months of 2020.[89]

Table 3-60 Day-ahead marginal resources by type/fuel used and technology: January through September, 2017 through 2021

		(Jan - Sep)				
Type/Fuel	Technology	2017	2018	2019	2020	2021
Up to Congestion Transaction	NA	79.84%	63.90%	57.70%	53.81%	36.14%
DEC	NA	10.03%	16.06%	18.41%	17.64%	26.50%
INC	NA	5.49%	9.24%	12.86%	12.41%	17.30%
Gas	CC	1.99%	5.08%	5.92%	9.90%	11.62%
Coal	Steam	1.74%	4.57%	4.23%	4.83%	6.32%
Wind	Wind	0.17%	0.16%	0.10%	0.24%	0.68%
Gas	Steam	0.37%	0.32%	0.39%	0.40%	0.52%
Dispatchable Transaction	NA	0.03%	0.13%	0.10%	0.08%	0.27%
Gas	CT	0.04%	0.20%	0.10%	0.24%	0.24%
Gas	RICE	0.02%	0.05%	0.04%	0.05%	0.12%
Oil	CT	0.19%	0.04%	0.04%	0.09%	0.06%
Price Sensitive Demand	NA	0.00%	0.02%	0.00%	0.00%	0.05%
Other	Solar	0.00%	0.03%	0.02%	0.01%	0.05%
Other	Steam	0.00%	0.01%	0.01%	0.05%	0.03%
Municipal Waste	RICE	0.00%	0.00%	0.01%	0.01%	0.03%
Uranium	Steam	0.06%	0.12%	0.06%	0.23%	0.03%
Oil	Steam	0.00%	0.05%	0.01%	0.01%	0.02%
Oil	RICE	0.01%	0.00%	0.00%	0.00%	0.01%
Oil	CC	0.00%	0.02%	0.00%	0.00%	0.01%
Water	Hydro	0.01%	0.00%	0.00%	0.00%	0.00%
Total		100.00%	100.00%	100.00%	100.00%	100.00%

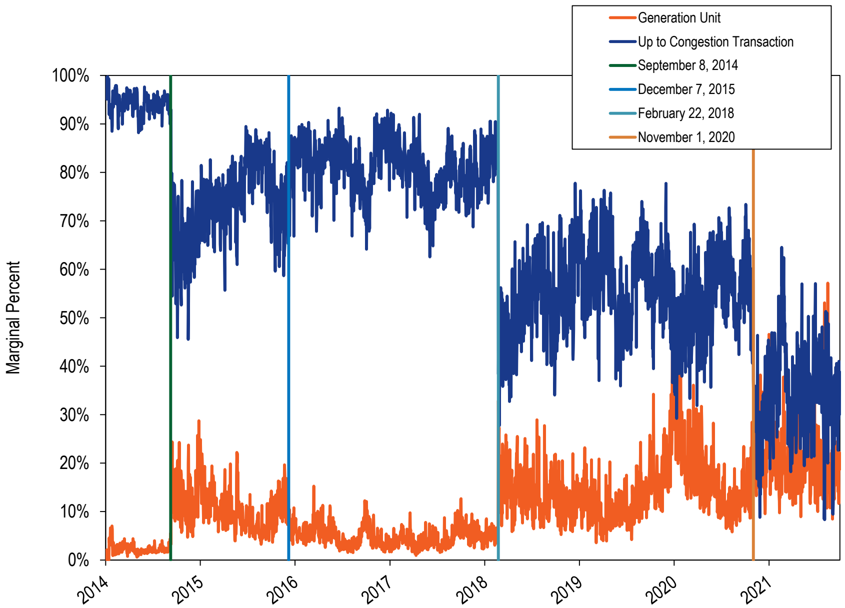
Figure 3-45 shows, for the day-ahead energy market from January 2014 through September 2021, the daily proportion of marginal resources that were up to congestion transactions and/or generation units. The UTC share decreased from 53.8 percent in the first nine months of 2020 to 36.1 percent in the first nine months of 2021.

Up to congestion transaction volumes decreased following the allocation of uplift charges on November 1, 2020.[90]

89 The data for September is from the pricing run result.

90 172 FERC ¶ 61,046 (2020).

Figure 3-45 Day-ahead marginal up to congestion transaction and generation units: January 2014 through September 2021

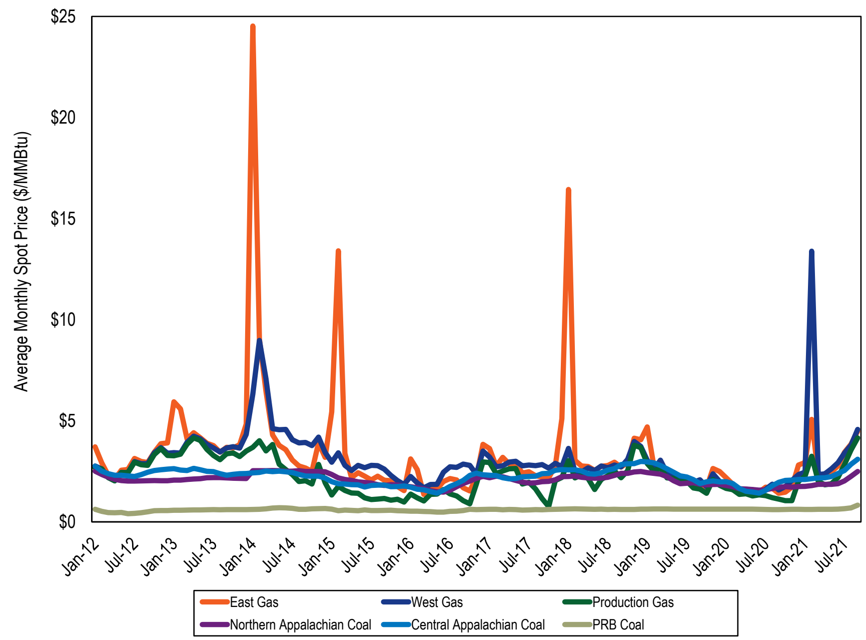


Fuel Price Trends and LMP

In a competitive market, changes in LMP follow 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 short run 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 also contribute to changes in the marginal cost of marginal units.

Figure 3-46 shows fuel prices in PJM for 2012 through September 2021. Natural gas prices increased in the first nine months of 2021 compared to the first nine months of 2020. Gas price volatility increased and gas price differences among regions increased. Western PJM gas prices were much higher in mid February than eastern PJM gas prices although both increased significantly. The price of natural gas in the Marcellus Shale production area is lower than in other areas of PJM. A number of new combined cycle plants have located in the production area since 2016. In the first nine months of 2021, the price of production gas was 95.9 percent higher than in the first nine months of 2020, the price of eastern natural gas was 99.2 percent higher and the price of western natural gas was 156.0 percent higher. The price of Northern Appalachian coal was 19.2 percent higher; the price of Central Appalachian coal was 42.3 percent higher; and the price of Powder River Basin coal was 5.5 percent higher.[91] The price of ULSD NY Harbor Barge was 83.2 percent higher.

Figure 3-46 Spot average fuel price comparison: 2012 through September 2021[92] ($/MMBtu)



91 Eastern natural gas consists of the average of Texas M3, Transco Zone 6 non-NY, Transco Zone 6 NY and Transco Zone 5 daily indices. Western natural gas prices are the average of Columbia Appalachia and Chicago Citygate daily indices. Production gas prices are the average of Dominion South Point, Tennessee Zone 4, and Transco Leidy Line receipts daily 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.

92 This figure is modified from the corresponding figure in the *2020 Quarterly State of the Market Report for PJM: January through June*, which included an error.

Table 3-61 compares the PJM real-time fuel-cost adjusted, load-weighted, average LMP in the first nine months of 2021 to the load-weighted, average LMP in the first nine months of 2020.[93] The real-time, load-weighted average LMP in the first nine months of 2021 increased by $14.46 or 58.9 percent from the real-time load-weighted, average LMP in the first nine months of 2020. The real-time load-weighted, average LMP for the first nine months of 2021 was 58.9 percent higher than the real-time, fuel-cost adjusted, load-weighted average LMP for the first nine months of 2021. The real-time, fuel-cost adjusted, load-weighted, average LMP for the first nine months of 2021 was 5.8 percent higher than the real-time, load-weighted, average LMP for the first nine months of 2020. If fuel and emissions costs in the first nine months of 2021 had been the same as in the first nine months of 2020, holding the market dispatch constant, the real-time, load-weighted, average LMP in the first nine months of 2021 would have been lower, $22.45 per MWh, than the observed $35.68 per MWh. Almost all, 91.5 percent of the increase in real-time, load-weighted, average LMP, $13.23 per MWh out of $14.46 per MWh, is directly attributable to fuel costs. Contributors to the other $1.23 per MWh are increased load, adjusted dispatch, including adjustments to dispatch due to changes in relative fuel costs among units, and lower markups.

Starting on September 1, 2021, the fuel-cost adjusted, load-weighted average LMP includes fuel cost associated with amortized start up and no load offers of the marginal fast start units in the pricing run.

Table 3-61 Real-time, fuel-cost adjusted, load-weighted average LMP (Dollars per MWh): January through September, 2020 and 2021

	2021 Fuel-Cost Adjusted, Load-Weighted LMP	2021 Load-Weighted LMP	Change	Percent Change
Average	$22.45	$35.68	$13.23	58.9%
	2020 Load-Weighted LMP	2021 Fuel-Cost Adjusted, Load-Weighted LMP	Change	Percent Change
Average	$21.22	$22.45	$1.23	5.8%
	2020 Load-Weighted LMP	2021 Load-Weighted LMP	Change	Change
Average	$21.22	$35.68	$14.46	68.1%

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

Table 3-62 shows the impact of each fuel type on the difference between the fuel-cost adjusted, load-weighted, average LMP and the load-weighted, average LMP in the first nine months of 2021. Table 3-62 shows that lower natural gas prices explain 87.7 percent of the fuel-cost related decrease in the real-time annual, load-weighted, average LMP in the first nine months of 2021 from 2020.

Table 3-62 Share of change in fuel-cost adjusted LMP ($/MWh) by fuel type: January through September, 2021 adjusted to 2020 fuel prices

Fuel Type	Share of Change in Fuel Cost Adjusted, Load Weighted LMP	Percent
Gas	$11.61	87.7%
Coal	$1.51	11.4%
Oil	$0.11	0.9%
Uranium	$0.00	0.0%
Municipal Waste	$0.00	0.0%
Other	$0.00	0.0%
NA	$0.00	0.0%
Wind	$0.00	0.0%
Total	$13.23	100.0%

Components of LMP

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 up to fourteen minute ahead forecasts of system conditions. Those offers can be decomposed into components including fuel costs, emission costs, variable operation and maintenance (VOM) 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, Maryland, New Jersey, and Virginia.[94] 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 reserves. In periods of scarcity when generators providing energy have to be dispatched down from their economic operating level to meet reserve requirements, the joint optimization of energy and reserves takes into account the opportunity cost of the reduced generation and the associated incremental cost to maintain reserves. If a unit incurring such opportunity costs is a marginal resource in the energy market, this opportunity cost will contribute to LMP. In addition, in periods when the SCED solution does not meet the reserve requirements, PJM should invoke shortage pricing. During 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.

Starting on September 1, 2021, the components shown in Table 3-63 and Table 3-64 are from the pricing run which include the impact of amortized start cost and amortized no load cost of the fast start marginal units. The components of LMP are shown in Table 3-63, including markup using unadjusted cost-based offers.[95] Table 3-63 shows that in the first nine months of 2021, 12.4 percent of the load-weighted LMP was the result of coal costs, 53.9 percent was the result of gas costs and 3.5 percent was the result of the cost of carbon emission allowances. Using unadjusted cost-based offers, negative markup was -5.2 percent of the load-weighted LMP. Using unadjusted cost-based offers, positive markup was 8.7 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. LMP may, at times, be set by transmission penalty factors. When a transmission constraint is binding and there are no cheaper 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. In the first nine months of 2021, 8.6 percent of the load-weighted LMP was the result of transmission penalty factors affecting LMPs. The percent contribution of transmission penalty factors was the highest since PJM removed constraint relaxation logic and allowed penalty factors to affect LMPs in February, 2019. The component NA is the unexplained portion of load-weighted LMP. For several intervals, PJM failed 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 NA component is the cumulative effect of excluding those five minute intervals. The percent column is the difference (in percentage points) in the proportion of LMP represented by each component in the first nine months of 2021 and 2020.

94 New Jersey withdrew from RGGI, effective January 1, 2012, and rejoined RGGI effective January 1, 2020. Virginia joined RGGI effective January 1, 2021.

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

Table 3-63 Components of real-time (Unadjusted), load-weighted average LMP: January through September, 2020 and 2021

	2020 (Jan - Sep)		2021 (Jan - Sep)		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change in Percent
Gas	$8.44	39.8%	$19.23	53.9%	14.1%
Coal	$5.21	24.6%	$4.24	11.9%	(12.7%)
Positive Markup	$1.16	5.5%	$3.10	8.7%	3.2%
Constraint Violation Adder	$1.68	7.9%	$3.08	8.6%	0.7%
Ten Percent Adder	$1.63	7.7%	$2.35	6.6%	(1.1%)
Variable Maintenance	$1.38	6.5%	$1.20	3.4%	(3.1%)
CO_2 Cost	$0.37	1.8%	$0.99	2.8%	1.0%
NA	$0.90	4.2%	$0.96	2.7%	(1.5%)
Variable Operations	$0.85	4.0%	$0.85	2.4%	(1.6%)
Ancillary Service Redispatch Cost	$0.14	0.7%	$0.29	0.8%	0.2%
Oil	$0.08	0.4%	$0.27	0.8%	0.4%
Scarcity Adder	$0.02	0.1%	$0.25	0.7%	0.6%
NO_x Cost	$0.01	0.0%	$0.25	0.7%	0.7%
Opportunity Cost Adder	$0.07	0.3%	$0.13	0.4%	0.0%
LPA Rounding Difference	$0.16	0.8%	$0.10	0.3%	(0.5%)
Increase Generation Adder	$0.07	0.3%	$0.10	0.3%	(0.0%)
LPA-SCED Differential	$0.01	0.1%	$0.09	0.3%	0.2%
Market-to-Market Adder	$0.00	0.0%	$0.06	0.2%	0.1%
Other	$0.00	0.0%	$0.01	0.0%	0.0%
Landfill Gas	($0.01)	(0.0%)	$0.00	0.0%	0.0%
SO_2 Cost	$0.00	0.0%	$0.00	0.0%	(0.0%)
Uranium	$0.00	0.0%	$0.00	0.0%	(0.0%)
Renewable Energy Credits	($0.00)	(0.0%)	($0.00)	(0.0%)	(0.0%)
Decrease Generation Adder	($0.02)	(0.1%)	($0.03)	(0.1%)	0.0%
Negative Markup	($0.94)	(4.4%)	($1.86)	(5.2%)	(0.8%)
Total	$21.22	100.0%	$35.68	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 3-63 and Table 3-67) markup is the difference between the price offer and the cost-based offer (unadjusted markup). In the second approach (Table 3-64 and Table 3-68), the 10 percent markup is removed from the cost-based offers of coal, gas, and oil units (adjusted markup).

The components of LMP are shown in Table 3-64, including markup using adjusted cost-based offers.

Table 3-64 Components of real-time (Adjusted), load-weighted, average LMP: January through September, 2020 and 2021

	2020 (Jan - Sep)		2021 (Jan - Sep)		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change in Percent
Gas	$8.44	39.8%	$19.23	53.9%	14.1%
Positive Markup	$1.70	8.0%	$4.41	12.4%	4.4%
Coal	$5.21	24.6%	$4.24	11.9%	(12.7%)
Constraint Violation Adder	$1.68	7.9%	$3.08	8.6%	0.7%
Variable Maintenance	$1.38	6.5%	$1.20	3.4%	(3.1%)
CO_2 Cost	$0.37	1.8%	$0.99	2.8%	1.0%
NA	$1.54	7.2%	$0.96	2.7%	(4.5%)
Variable Operations	$0.85	4.0%	$0.85	2.4%	(1.6%)
Ancillary Service Redispatch Cost	$0.14	0.7%	$0.29	0.8%	0.2%
Oil	$0.08	0.4%	$0.27	0.8%	0.4%
Scarcity Adder	$0.02	0.1%	$0.25	0.7%	0.6%
NO_x Cost	$0.01	0.0%	$0.25	0.7%	0.7%
Opportunity Cost Adder	$0.07	0.3%	$0.13	0.4%	0.0%
LPA Rounding Difference	$0.16	0.8%	$0.10	0.3%	(0.5%)
Increase Generation Adder	$0.07	0.3%	$0.10	0.3%	(0.0%)
LPA-SCED Differential	$0.01	0.1%	$0.09	0.3%	0.2%
Market-to-Market Adder	$0.00	0.0%	$0.06	0.2%	0.1%
Other	$0.00	0.0%	$0.01	0.0%	0.0%
Landfill Gas	($0.01)	(0.0%)	$0.00	0.0%	0.0%
Ten Percent Adder	$0.00	0.0%	$0.00	0.0%	0.0%
SO_2 Cost	$0.00	0.0%	$0.00	0.0%	(0.0%)
Uranium	$0.00	0.0%	$0.00	0.0%	(0.0%)
Renewable Energy Credits	($0.00)	(0.0%)	($0.00)	(0.0%)	(0.0%)
Decrease Generation Adder	($0.02)	(0.1%)	($0.03)	(0.1%)	0.0%
Negative Markup	($0.49)	(2.3%)	($0.82)	(2.3%)	0.0%
Total	$21.22	100.0%	$35.68	100.0%	0.0%

PJM implemented fast start pricing on September 1, 2021. The commitment cost related components of LMP are shown in Table 3-65, including markup using unadjusted cost-based offers for September 2021. In the first month of the fast start pricing in PJM, 2.8 percent of the load-weighted average LMP was the result of commitment costs.

Table 3-65 Commitment cost related components of real-time (Unadjusted), load-weighted average LMP: September 2021

	Commitment Components (Sep 2021)		Other Components (Sep 2021)		Total (Sep 2021)	
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Contribution to LMP	Percent
Gas	$1.11	2.2%	$28.01	56.4%	$29.12	58.7%
Postive Markup	$0.00	0.0%	$5.40	10.9%	$5.40	10.9%
Coal	$0.00	0.0%	$3.30	6.6%	$3.30	6.6%
Ten Percent Adder	$0.12	0.2%	$3.10	6.2%	$3.21	6.5%
Constraint Violation Adder	$0.00	0.0%	$2.88	5.8%	$2.88	5.8%
NA	$0.00	0.0%	$2.74	5.5%	$2.74	5.5%
Variable Maintenance	$0.31	0.6%	$1.26	2.5%	$1.58	3.2%
CO_2 Cost	$0.01	0.0%	$1.04	2.1%	$1.04	2.1%
Variable Operations	$0.00	0.0%	$0.87	1.8%	$0.87	1.8%
Market-to-Market Adder	$0.00	0.0%	$0.49	1.0%	$0.49	1.0%
Lpa	$0.00	0.0%	$0.34	0.7%	$0.34	0.7%
Opportunity Cost Adder	$0.00	0.0%	$0.30	0.6%	$0.30	0.6%
NO_x Cost	$0.01	0.0%	$0.27	0.5%	$0.27	0.5%
Increase Generation Adder	$0.00	0.0%	$0.11	0.2%	$0.11	0.2%
Ancillary Service Redispatch Cost	$0.00	0.0%	$0.10	0.2%	$0.10	0.2%
Oil	$0.00	0.0%	$0.01	0.0%	$0.01	0.0%
Other	$0.00	0.0%	$0.01	0.0%	$0.01	0.0%
SO_2 Cost	$0.00	0.0%	$0.00	0.0%	$0.00	0.0%
Scarcity Adder	$0.00	0.0%	$0.00	0.0%	$0.00	0.0%
LPA Rounding Difference	$0.00	0.0%	$0.00	0.0%	$0.00	0.0%
Decrease Generation Adder	$0.00	0.0%	($0.02)	(0.0%)	($0.02)	(0.0%)
Renewable Energy Credits	$0.00	0.0%	($0.02)	(0.0%)	($0.02)	(0.0%)
Negative Markup	($0.17)	(0.3%)	($1.93)	(3.9%)	($2.10)	(4.2%)
Total	$1.39	2.8%	$48.25	97.2%	$49.63	100.0%

The components of LMP for the dispatch run and the pricing run are shown in Table 3-66, including markup using unadjusted cost-based offers for the first month of fast start pricing in PJM.

Table 3-66 Comparison of components of real-time (Unadjusted), load-weighted, average LMP in the dispatch run and pricing run: September 2021

	Dispatch (Sep 2021)		Pricing (Sep 2021)		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change in Percent
Gas	$27.29	57.2%	$29.12	58.7%	1.5%
Positive Markup	$5.77	12.1%	$5.40	10.9%	(1.2%)
Coal	$3.65	7.6%	$3.30	6.6%	(1.0%)
Ten Percent Adder	$3.07	6.4%	$3.21	6.5%	0.1%
Constraint Violation Adder	$2.71	5.7%	$2.88	5.8%	0.1%
NA	$2.51	5.3%	$2.74	5.5%	0.3%
Variable Maintenance	$1.09	2.3%	$1.58	3.2%	0.9%
CO_2 Cost	$1.13	2.4%	$1.04	2.1%	(0.3%)
Variable Operations	$0.79	1.6%	$0.87	1.8%	0.1%
Market-to-Market Adder	$0.36	0.8%	$0.49	1.0%	0.2%
LPA Rounding Difference	$0.29	0.6%	$0.34	0.7%	0.1%
Opportunity Cost Adder	$0.20	0.4%	$0.30	0.6%	0.2%
NO_x Cost	$0.29	0.6%	$0.27	0.5%	(0.1%)
Increase Generation Adder	$0.17	0.3%	$0.11	0.2%	(0.1%)
Ancillary Service Redispatch Cost	$0.07	0.1%	$0.10	0.2%	0.1%
Oil	$0.01	0.0%	$0.01	0.0%	(0.0%)
Other	$0.02	0.0%	$0.01	0.0%	(0.0%)
SO_2 Cost	$0.00	0.0%	$0.00	0.0%	(0.0%)
Scarcity Adder	$0.00	0.0%	$0.00	0.0%	0.0%
LPA-SCED Differential	$0.00	0.0%	$0.00	0.0%	0.0%
Landfill Gas	$0.01	0.0%	$0.00	0.0%	(0.0%)
Decrease Generation Adder	($0.03)	(0.1%)	($0.02)	(0.0%)	0.0%
Renewable Energy Credits	($0.01)	(0.0%)	($0.02)	(0.0%)	(0.0%)
Negative Markup	($1.64)	(3.4%)	($2.10)	(4.2%)	(0.8%)
Total	$47.73	100.0%	$49.63	100.0%	0.0%

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, 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.

PJM implemented fast start pricing on September 1, 2021 in the day-ahead market as well. The marginal resources and sensitivity factors are different between the dispatch run and pricing run. Since PJM uses LMPs generated in the pricing run as settlement LMPs, in Table 3-67 and Table 3-68, the components of day-ahead, load-weighted, average LMP in the September of 2021 are calculated using marginal resource and sensitivity factor data from the pricing run and original data is used in 2020 and the first eight months of 2021.

Table 3-67 shows the components of the PJM day-ahead, annual, load-weighted, average LMP. In the first nine months of 2021, 26.1 percent of the load-weighted LMP was the result of gas costs, 12.6 percent of the load-weighted LMP was the result of coal costs, 29.5 percent was the result of DECs, 13.1 percent was the result of INCs and 2.6 percent was the result of UTCs.

Table 3-67 Components of day-ahead, (unadjusted), load-weighted average LMP (Dollars per MWh): January through September, 2020 and 2021

	2020 (Jan - Sep)		2021 (Jan - Sep)		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change in Percent
DEC	$4.81	23.0%	$10.48	29.5%	6.6%
Gas	$3.87	18.5%	$9.27	26.1%	7.6%
INC	$3.24	15.4%	$4.66	13.1%	(2.3%)
Coal	$5.50	26.2%	$4.48	12.6%	(13.6%)
Positive Markup	$1.00	4.8%	$1.82	5.1%	0.4%
Ten Percent Cost Adder	$1.11	5.3%	$1.62	4.6%	(0.7%)
Up to Congestion Transaction	$0.71	3.4%	$0.92	2.6%	(0.8%)
CO_2	$0.19	0.9%	$0.72	2.0%	1.1%
Variable Operating Cost	$0.60	2.9%	$0.71	2.0%	(0.9%)
Variable Maintenance Cost	$0.92	4.4%	$0.70	2.0%	(2.4%)
Dispatchable Transaction	$0.01	0.0%	$0.59	1.7%	1.6%
NO_x	$0.02	0.1%	$0.25	0.7%	0.6%
Oil	$0.02	0.1%	$0.17	0.5%	0.4%
Price Sensitive Demand	$0.01	0.0%	$0.16	0.4%	0.4%
Municipal Waste	$0.00	0.0%	$0.06	0.2%	0.2%
Other	$0.00	0.0%	$0.00	0.0%	0.0%
SO_2	$0.00	0.0%	$0.00	0.0%	(0.0%)
Uranium	$0.00	0.0%	$0.00	0.0%	(0.0%)
Wind	($0.00)	(0.0%)	($0.13)	(0.4%)	(0.4%)
Negative Markup	($1.05)	(5.0%)	($0.98)	(2.8%)	2.3%
NA	$0.01	0.1%	$0.00	0.0%	(0.1%)
Total	$20.95	100.0%	$35.51	100.0%	0.0%

Table 3-68 shows the components of the PJM day-ahead, annual, load-weighted, average LMP including the adjusted markup calculated by excluding the 10 percent adder from the coal, gas or oil units.

Table 3-68 Components of day-ahead, (adjusted), load-weighted average LMP (Dollars per MWh): January through September, 2020 and 2021

	2020 (Jan - Sep)		2021 (Jan - Sep)		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change in Percent
DEC	$4.81	23.0%	$10.48	29.5%	6.6%
Gas	$3.87	18.5%	$9.27	26.1%	7.6%
INC	$3.24	15.4%	$4.66	13.1%	(2.3%)
Coal	$5.50	26.2%	$4.48	12.6%	(13.6%)
Positive Markup	$1.63	7.8%	$2.89	8.1%	0.4%
Up to Congestion Transaction	$0.71	3.4%	$0.92	2.6%	(0.8%)
CO_2	$0.19	0.9%	$0.72	2.0%	1.1%
Variable Operating Cost	$0.60	2.9%	$0.71	2.0%	(0.9%)
Variable Maintenance Cost	$0.92	4.4%	$0.70	2.0%	(2.4%)
Dispatchable Transaction	$0.01	0.0%	$0.59	1.7%	1.6%
NO_x	$0.02	0.1%	$0.25	0.7%	0.6%
Oil	$0.02	0.1%	$0.17	0.5%	0.4%
Price Sensitive Demand	$0.01	0.0%	$0.16	0.4%	0.4%
Municipal Waste	$0.00	0.0%	$0.06	0.2%	0.2%
Ten Percent Cost Adder	$0.00	0.0%	$0.01	0.0%	(0.0%)
Other	$0.00	0.0%	$0.00	0.0%	0.0%
SO_2	$0.00	0.0%	$0.00	0.0%	(0.0%)
Uranium	$0.00	0.0%	$0.00	0.0%	(0.0%)
Wind	($0.00)	(0.0%)	($0.13)	(0.4%)	(0.4%)
Negative Markup	($0.57)	(2.7%)	($0.43)	(1.2%)	1.5%
NA	$0.01	0.1%	$0.00	0.0%	(0.1%)
Total	$20.95	100.0%	$35.51	100.0%	(0.0%)

Table 3-69 compares the components of LMP between the dispatch run and the pricing run for September. The marginal resources and sensitivity factors are different between the dispatch run and pricing run. The dispatch run components of day-ahead, load-weighted average LMP are calculated using the marginal resources and sensitivity factors from the dispatch run result and the pricing run components of day-ahead, load-weighted, average LMP are calculated using the marginal resources and sensitivity factors from the pricing run result. The marginal DEC contribution of day-ahead load-weighted LMP decreased 4.6 percent and the marginal coal generation unit contribution of day-ahead, load-weighted average LMP increased 2.5 percent from the dispatch run to the pricing run. Table 3-70 compares components of the PJM day-ahead, annual, load-weighted average LMP including the adjusted markup calculated by excluding the 10 percent adder from the coal, gas or oil units between the dispatch run and the pricing run.

Table 3-69 Components of day-ahead (Unadjusted), load-weighted average LMP in the dispatch run and pricing run: September 2021

	Dispatch Run (Sep 2021)		Pricing Run (Sep 2021)		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change in Percent
DEC	$15.12	32.8%	$13.04	28.2%	(4.6%)
Gas	$12.94	28.1%	$12.14	26.2%	(1.8%)
INC	$6.55	14.2%	$6.28	13.6%	(0.6%)
Coal	$3.61	7.8%	$4.77	10.3%	2.5%
Up to Congestion Transaction	$0.85	1.8%	$2.61	5.6%	3.8%
Positive Markup	$2.84	6.2%	$2.56	5.5%	(0.6%)
Ten Percent Cost Adder	$1.87	4.0%	$1.94	4.2%	0.1%
Variable Operating Cost	$0.58	1.3%	$0.84	1.8%	0.5%
Dispatchable Transaction	$0.84	1.8%	$0.73	1.6%	(0.2%)
CO_2	$0.74	1.6%	$0.65	1.4%	(0.2%)
Variable Maintenance Cost	$0.60	1.3%	$0.60	1.3%	(0.0%)
NO_x	$0.29	0.6%	$0.40	0.9%	0.2%
Oil	$0.00	0.0%	$0.04	0.1%	0.1%
Price Sensitive Demand	$0.00	0.0%	$0.02	0.0%	0.0%
SO_2	$0.00	0.0%	$0.00	0.0%	0.0%
Wind	($0.12)	(0.3%)	($0.08)	(0.2%)	0.1%
Negative Markup	($0.56)	(1.2%)	($0.25)	(0.5%)	0.7%
NA	($0.02)	(0.1%)	$0.00	0.0%	0.1%
Total	$46.13	100.0%	$46.29	100.0%	0.0%

Table 3-70 Components of day-ahead (adjusted), load-weighted average LMP in the dispatch run and pricing run: September 2021

	Dispatch Run (Sep 2021)		Pricing Run (Sep 2021)		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change in Percent
DEC	$15.12	32.8%	$13.04	28.2%	(4.6%)
Gas	$12.94	28.1%	$12.14	26.2%	(1.8%)
INC	$6.55	14.2%	$6.28	13.6%	(0.6%)
Coal	$3.61	7.8%	$4.77	10.3%	2.5%
Positive Markup	$4.21	9.1%	$4.12	8.9%	(0.2%)
Up to Congestion Transaction	$0.85	1.8%	$2.61	5.6%	3.8%
Variable Operating Cost	$0.58	1.3%	$0.84	1.8%	0.5%
Dispatchable Transaction	$0.84	1.8%	$0.73	1.6%	(0.2%)
CO_2	$0.74	1.6%	$0.65	1.4%	(0.2%)
Variable Maintenance Cost	$0.60	1.3%	$0.60	1.3%	(0.0%)
NO_x	$0.29	0.6%	$0.40	0.9%	0.2%
Negative Markup	($0.10)	(0.2%)	$0.09	0.2%	0.4%
Oil	$0.00	0.0%	$0.04	0.1%	0.1%
Ten Percent Cost Adder	$0.03	0.1%	$0.03	0.1%	(0.0%)
Price Sensitive Demand	$0.00	0.0%	$0.02	0.0%	0.0%
SO_2	$0.00	0.0%	$0.00	0.0%	0.0%
Wind	($0.12)	(0.3%)	($0.08)	(0.2%)	0.1%
NA	($0.02)	(0.1%)	$0.00	0.0%	0.1%
Total	$46.13	100.0%	$46.29	100.0%	0.0%

Shortage

PJM's energy market experienced five minute shortage pricing for 19 five minute intervals on ten days in the first nine months of 2021. PJM implemented fast start pricing on September 1, 2021. In September 2021, there were two five minute intervals with shortage pricing, and there were no differences in the shortage pricing results from the dispatch and pricing run during these two intervals. Table 3-71 shows a summary of the number of days emergency alerts, warnings and actions were declared in PJM in the first nine months of 2020 and 2021. In the first nine months of 2021, there were no emergency actions that triggered a Performance Assessment Interval (PAI). The days with shortage pricing intervals did not correspond to the days with emergency alerts.

Table 3-71 Summary of emergency events declared: January through September, 2020 and 2021

	Number of days events declared	
	2020	2021
Event Type	(Jan - Sep)	(Jan - Sep)
Cold Weather Alert	3	6
Hot Weather Alert	19	23
Maximum Emergency Generation Alert	0	0
Primary Reserve Alert	0	0
Voltage Reduction Alert	0	0
Primary Reserve Warning	0	0
Voltage Reduction Warning	0	0
Pre Emergency Mandatory Load Management Reduction Action	0	0
Emergency Mandatory Load Management Reduction Action (30, 60 or 120 minute lead time)	0	0
Maximum Emergency Action	0	0
Emergency Energy Bids Requested	0	0
Voltage Reduction Action	0	0
Shortage Pricing	1	10
Energy export recalls from PJM capacity resources	0	0

Figure 3-47 shows the number of days that weather and capacity emergency alerts were issued in PJM in the first nine months from 2012 through 2021.

Figure 3-47 Declared emergency alerts: January through September, 2012 through 2021

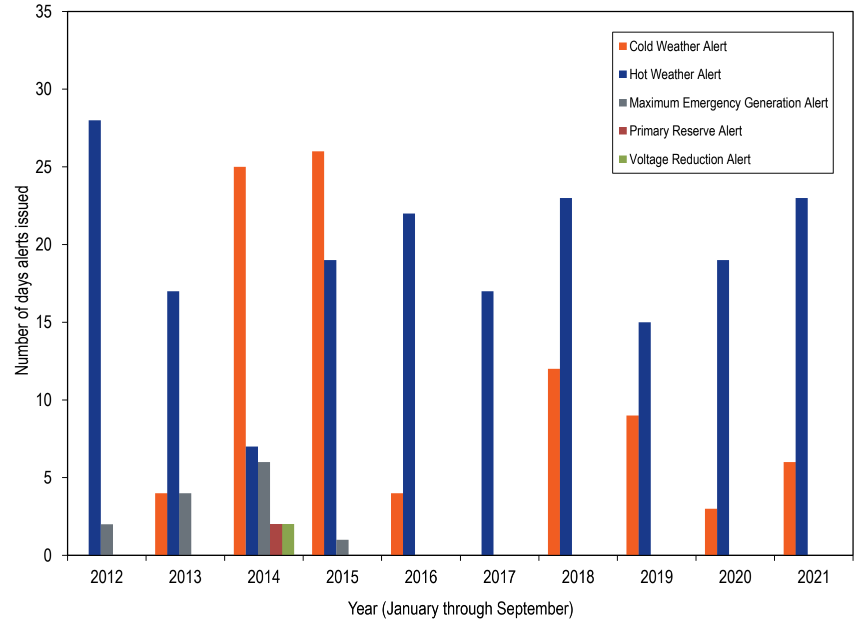
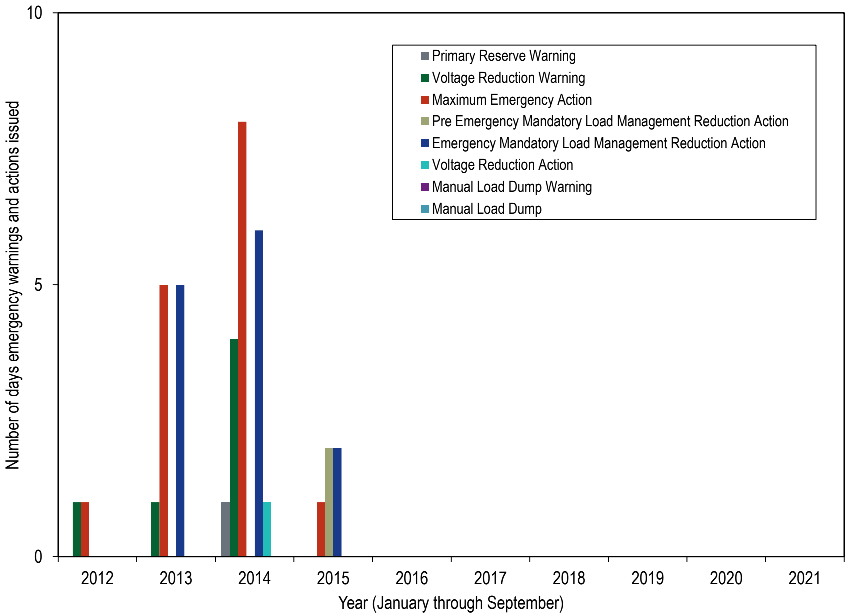


Figure 3-48 shows the number of days that emergency warnings and actions were declared in PJM in the first nine months from 2012 through 2021.

Figure 3-48 Declared emergency warnings and actions: January through September, 2012 through 2021



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.

Table 3-72 provides a description of PJM declared emergency procedures.[96] [97] [98] [99]

96 See PJM. "Manual 13: Emergency Operations," Rev. 78 (Jan. 27, 2021), Section 3.3 Cold Weather Alert.
97 See PJM. "Manual 13: Emergency Operations," Rev. 78 (Jan. 27, 2021), Section 3.4 Hot Weather Alert.
98 See PJM. "Manual 13: Emergency Operations," Rev. 78 (Jan. 27, 2021), Section 2.3.1 Advanced Notice Emergency Procedures: Alerts.
99 See PJM. "Manual 13: Emergency Operations," Rev. 78 (Jan. 27, 2021), Section 2.3.2 Real-Time Emergency Procedures (Warnings and Actions).

Table 3-72 Description of emergency procedures

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

Table 3-73 shows the dates when emergency alerts and warnings were declared and when emergency actions were implemented in the first nine months of 2021.

Table 3-73 Declared emergency alerts, warnings and actions: January through September, 2021

Date	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	Maximum Emergency Generation Action	Pre-Emergency Mandatory Load Management Reduction	Emergency Mandatory Load Management Reduction	Voltage Reduction	Manual Load Dump Warning	Manual Load Dump Action	Load Shed Directive
2/7/2021	Western except EKPC													
2/8/2021	Western except EKPC													
2/9/2021	COMED													
2/10/2021	COMED													
2/14/2021	COMED													
2/15/2021	Western													
5/23/2021		Mid-Atlantic and Southern												
6/6/2021		Mid-Atlantic												
6/7/2021		Mid-Atlantic												
6/28/2021		RTO except COMED												
6/29/2021		RTO except COMED												
6/30/2021		Mid-Atlantic and Southern												
7/6/2021		RTO												
7/7/2021		Mid-Atlantic and Southern												
7/15/2021		Mid-Atlantic and Southern												
7/16/2021		Mid-Atlantic and Southern												
7/17/2021		Mid-Atlantic and Southern												
7/27/2021		Mid-Atlantic												
8/9/2021		Mid-Atlantic and Western except COMED												
8/10/2021		Mid-Atlantic and COMED												
8/11/2021		RTO												
8/12/2021		RTO												
8/13/2021		Mid-Atlantic and Southern												
8/24/2021		RTO												
8/25/2021		RTO												
8/26/2021		RTO except COMED												
8/27/2021		Mid-Atlantic and Southern												
9/14/2021		Mid-Atlantic and Southern												
9/15/2021		Mid-Atlantic												

Power Balance Constraint Violation

On October 1, 2019, the power balance constraint was violated in 11 approved RT SCED solutions. On February 16, 2020, the power balance constraint was violated in one approved RT SCED solution which was used to set prices for three five minute intervals. On March 22, 2021, the power balance constraint was violated in one approved RT SCED solution. In the RT SCED optimization, the power balance constraint enforces the requirement that total dispatched generation (supply) equals the sum total of forecasted load, losses and net interchange (demand). The power balance constraint is violated when supply is less than demand. In some cases, the power balance constraint is violated while the reserve requirements are satisfied.

The current process for meeting energy and reserve requirements in real time, and pricing the system conditions when RT SCED forecasts that energy supply is less than the demand for energy and reserves, is opaque and not defined in the PJM governing documents. It is unclear whether and how PJM would convert reserves to energy before violating power balance. It is unclear whether and when PJM would use its authority under the tariff to curtail exports from PJM capacity resources to meet the power balance constraint. It is unclear whether PJM would maintain a minimum level of synchronized reserves even if that would result in a controlled load shed. The current RT SCED does not have a mechanism to convert inflexible reserves procured by ASO to energy to satisfy the power balance constraint.[100] SCED solutions from October 1, 2019, February 16, 2020, and April 21, 2020, indicate that the currently defined logic meets transmission constraint limits and reserve requirements but violates the power balance constraint, and does not reflect this constraint violation in prices. This logic, if correctly described, is not consistent with basic economics. The overall solution is complex and must be integrated with the approach to shortage pricing.

The MMU recommends that PJM clarify, modify and document its process for dispatching reserves and energy when SCED indicates that supply is less than total demand including forecasted load and reserve requirements. The modifications should define: a SCED process to economically convert reserves to energy; a process for the recall of energy from capacity resources; and the minimum level of synchronized reserves that would trigger load shedding.

Table 3-74 shows the number of five minute intervals for which the RT SCED solutions used to set prices did not balance demand and supply. PJM reran the RT SCED with artificially increased supply to satisfy the power balance constraint. In the first nine months of 2021, there were three five minute intervals using an RT SCED solution with a violated power balance constraint. The average energy component of LMP in that five minute interval with artificially increased supply to satisfy the power balance constraint was $1,582.14 per MWh.[101]

Table 3-74 Number of five minute intervals using RT SCED solutions with violated power balance constraint by year

Year	Number of five minute intervals	Average Energy Component of LMP ($/MWh)
2013	-	$0.00
2014	655	$36.29
2015	71	($0.76)
2016	42	$93.06
2017	31	$279.86
2018	16	$268.21
2019	36	$845.48
2020	5	$351.56
2021 (Jan - Sep)	3	$1,582.14

Balancing Ratio for Local Emergency Events

The balancing ratio is theoretically defined as the ratio of actual load and reserve requirements in an area during an emergency event to the total committed capacity in the area. In the case of the PAIs declared in 2018 that were triggered due to transmission outages in limited locations, if the area is defined as the location where the load was shed, the balancing ratio is undefined because there were no committed resources in the area, other than less than

100 Inflexible reserves are those reserves that clear in the hour ahead Ancillary Service Optimizer (ASO) but cannot be dispatched in the real time dispatch tool, RT SCED.

101 The energy component of LMP, or the shadow price of the power balance constraint, is the incremental cost of meeting a one MWh increase in the system load.

1.0 MW of demand response.[102] It is not appropriate or correct to calculate a balancing ratio as a measure of capacity needed during these events by defining a wider area to include committed capacity. It is also not appropriate to use a balancing ratio defined in that way in defining the capacity market offer cap. PJM calculated the balancing ratio for the localized load shed that occurred in the AEP Edison area in 2018 and used the average balancing ratio during the event to calculate the capacity market seller offer cap for all LDAs for the 2022/2023 Delivery Year.[103] These events occurred in a very small local area where no capacity resources were held to CP performance requirements. Assessing nonperformance to resources located in the wider area would not be appropriate because their performance would not have helped, and may have even exacerbated the transmission issues identified during these events. These events also do not reflect the type of events that are modeled to define the target installed reserve margin in the capacity market. The MMU recommends, if the capacity market seller offer cap were to be calculated using the historical average balancing ratio, that PJM not include the balancing ratios calculated for localized Performance Assessment Intervals (PAIs), and only include those events that trigger emergencies at a defined zonal or higher level.

Performance Assessment Intervals

PJM currently triggers a PAI any time it declares a pre-emergency load management reduction action, or a more severe emergency action.[104] PJM's trigger for PAI is subjective, and it should be based on a quantifiable, transparent metric of the need for capacity in the PJM system. For example, in ISO New England, under the Pay for Performance design, resources are assessed for performance during Capacity Scarcity Conditions ("CSCs") that occur when the system or local area is short on 10 and 30 minute nonspinning reserves.[105] Reserve shortages are determined based on a predefined reserve requirement, and the reserve calculation that is embedded in the real-time dispatch tool.

The October 2, 2019, PAI provided actual data and evidence on the issues with PJM's triggers, and PJM's treatment of excused MW. The PAI on October 2, 2019, was triggered when PJM declared a pre-emergency load management reduction action in the AEP, BGE, DOM and PEPCO Zones based on anticipated high load relative to the available supply. The actual load was significantly lower than forecasted.[106]

On October 1, 2019, the day before the PAI, PJM did experience high load relative to the available supply. The system conditions were reflected in the market outcomes with multiple intervals of high prices, and reserve shortages.[107] The decision to declare a pre-emergency load management reduction action on October 2, 2019, was based on an expectation of the repetition of the events on October 1, 2019, which did not materialize. This illustrates the shortcomings of triggering PAIs based on PJM operator declared emergency actions or pre-emergency load management reduction, instead of using a quantitative metric that is readily available to PJM, such as reserves.[108] Given this implementation, it can no longer be assumed that PAI would occur when the PJM region, or a subset of zones in the PJM region are experiencing capacity shortage conditions.

Shortage and Shortage Pricing

In electricity markets, shortage means that demand, including reserve requirements, is nearing the limits of the currently available capacity of the system. Shortage pricing is a mechanism for signaling scarcity conditions through high energy prices. Under the PJM rules that were in place through September 30, 2012, shortage pricing resulted from the exercise of aggregate market power 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 shortage pricing and made it difficult to distinguish between market power and shortage pricing. Shortage pricing is an administrative pricing

102 See *2018 State of the Market Report for PJM*, Volume II, Section 3: Energy Market, at Scarcity, pp. 201 – 202.
103 *See* PJM, "Capacity Market Seller Offer Cap Values," (March 15, 2019), which can be accessed at <https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2022-2023/2022-2023-cp-market-seller-offer-cap-values.ashx?la=en?>.
104 OATT Definitions at "Emergency Action".
105 ISO New England Inc. Internal Market Monitor, "2018 Annual Markets Report," (May 23, 2019) at 156 (§ 6.2.2 (Pay-for-Performance Outcomes)).
106 In a report reviewing the PAI, PJM stated: "The most striking anomaly was load levels in the AEP and Mid-Atlantic zones that came in significantly below forecast." *See* PJM, "A Review of the October 2019 Performance Assessment Event," (2019) at 1, which can be accessed at <https://www.pjm.com/-/media/markets-ops/rpm/review-of-october-2019-performance-assessment-event.ashx>.
107 *See* Monitoring Analytics, LLC, *2019 State of the Market Report for PJM*, Volume 2: Section 3 Energy Market at 176 –180 (Analysis of October 1 Events).
108 There are existing issues with the accuracy of reserve measurement in PJM, and they should also be resolved by improving generator modeling in the energy market.

mechanism in which PJM sets a high energy price at a predetermined level when the system operates with less real-time reserves than required.

In the first nine months of 2021, there were 19 five minute intervals with shortage pricing that occurred on ten days in PJM.

With Order No. 825, the Commission required each RTO/ISO to trigger shortage pricing for any dispatch and pricing interval in which a shortage of energy or operating reserves is indicated by the RTO/ISO's software.[109] Prior to May 11, 2017, if the dispatch tools (Intermediate-Term SCED and Real-Time SCED) reflected a shortage of reserves (primary or synchronized) for a time period shorter than a defined threshold (30 minutes), it was considered a transient shortage, a shortage event was not declared, and shortage pricing was not implemented. As of May 11, 2017, the rule requires PJM to trigger shortage pricing for any five minute interval for which the Real-Time SCED (Security Constrained Economic Dispatch) indicates a shortage of synchronized reserves or primary reserves. PJM did not implement the rule as intended in Order No. 825, because RT SCED can indicate a shortage that PJM does not use in pricing. In January 2019, PJM updated its business rules in Manual 11 to describe PJM's implementation of the five minute shortage pricing process. PJM Manual 11 states that shortage pricing is triggered when an approved RT SCED case that was used in the Locational Pricing Calculator (LPC) indicates a shortage of reserves. Beginning February 24, 2020, PJM changed the RT SCED automatic execution frequency to once every four minutes, from the previous three minutes. On June 22, 2020, PJM reduced the frequency of automatic RT SCED executions to match the frequency of pricing at five minutes, which reduced the frequency of unpriced shortage solutions. Prior to September 1, 2021, the reserves calculated in the LPC solution, and the reserves calculated in the reference RT SCED case used by the LPC solution were the same. With the implementation of fast start pricing on September 1, 2021, shortage pricing is now triggered by the pricing run in LPC that incorporates integer relaxation for certain units deemed fast start by PJM. This can lead to differences between the dispatched reserves in RT SCED, and the reserves calculated in the pricing run in LPC. In the pricing run in LPC, shortage pricing may be triggered even when there is no actual shortage in dispatched reserves as determined by the reference RT SCED solution.

Voltage reduction actions and manual load dump actions are also triggers for shortage pricing, reflecting the fact that when operators need to take these emergency actions to maintain reliability, the system is short reserves and prices should reflect that condition, even if the data do not show a shortage of reserves.[110]

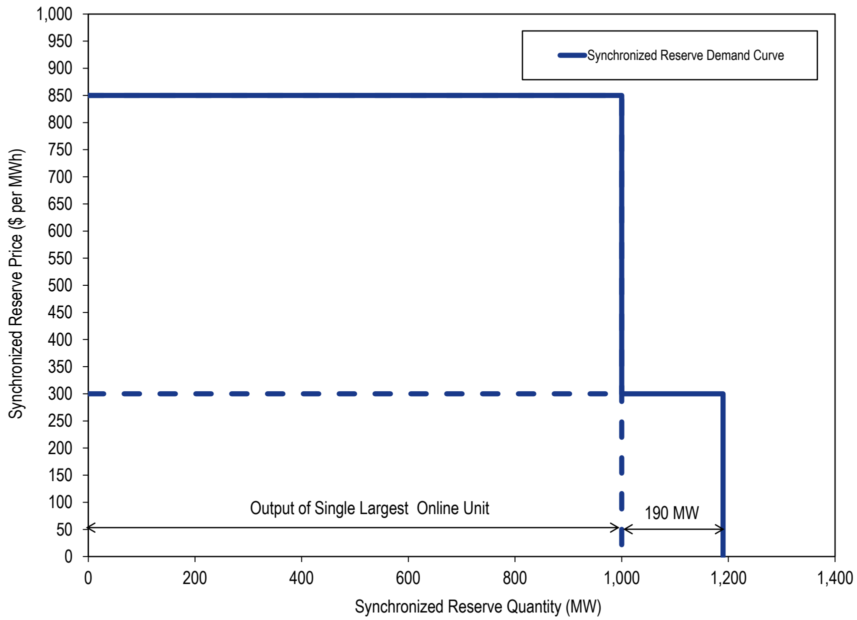
Operating Reserve Demand Curves

Since July 12, 2017, the PJM synchronized reserve requirement in a reserve zone or a subzone is the actual output of the single largest online unit in that reserve zone or subzone. The primary reserve requirement in a reserve zone or a subzone is 150 percent of the actual output of the single largest online unit in that reserve zone or subzone. The first step of the demand curves for primary and synchronized reserves are set at the primary and synchronized reserve requirement. Since the primary and synchronized reserve requirements are based on the actual output of the largest resource, the MW value of the first step changes in real time based on the real-time dispatch solution. The first step is priced at $850 per MWh. The second step of the primary and synchronized reserve demand curves extends the primary and synchronized reserve requirements. The extended primary and synchronized reserve requirements are defined as the primary and synchronized reserve requirements, plus 190 MW. This 190 MW second step is priced at $300 per MWh. Figure 3-49 shows an example of the updated synchronized reserve demand curve when the output of the single largest unit in the region equals 1,000 MW.

109 *Settlement Intervals and Shortage Pricing in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Order No. 825, 155 FERC ¶ 61,276 at P 162 (2016).

110 *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).

Figure 3-49 Synchronized reserve demand curve showing the permanent second step



Shortage Pricing and Energy Price Formation

The current operating reserve demand curves (ORDC) in PJM define an administrative price for estimated reserves (primary and synchronized reserves) up to the extended reserve requirement quantities. The demand curve shown in Figure 3-49 drops to a zero price for quantities above the extended reserve requirement. The price for reserve quantities less than the reserve requirement is $850 per MWh, and the price for reserve quantities above the reserve requirement to 190 MW above the reserve requirement is $300 per MWh.

The shortage prices set by the ORDC are added to LMP during shortages. When multiple reserve products are short or when reserves are short in multiple zones, the ORDC prices are additive. Currently, the highest possible shortage penalty in LMP is $3,400 per MWh, which is the $850 per MWh price times four, for two reserve products (synchronized reserve and nonsynchronized reserve) times two reserve zones, RTO and MAD. However, PJM caps the system marginal energy price at $3,750, which is the sum of the highest possible energy offer, the synchronized reserve penalty factor, the primary reserve penalty factor, and a $50 per MWh threshold. The current market rules cap the additive reserve shortage penalty factors for the MAD synchronized reserve market clearing price to the sum of the synchronized reserve penalty factor and the primary reserve penalty factor, which is $1,700 per MW.[111] The $1,700 per MWh penalty applies any time PJM initiates a manual load dump action or voltage reduction action.[112]

Table 3-75 shows six example scenarios, under the current ORDCs, with combinations of energy offers, reserve shortage penalty factors and transmission constraint penalty factors that can add up to produce high LMPs at sample pnodes in the MAD Reserve Subzone and outside the MAD Reserve Subzone.

In scenario B, there is a reserve shortage for both primary and synchronized reserves in both MAD and RTO Reserve Zones that results in a $1,700 per MWh reserve shortage penalty in the RTO zone LMP and a $3,400 per MWh reserve shortage penalty in the MAD zone LMP. The marginal resource for energy is in the RTO zone, and the RTO to MAD reserve transfer constraint is not binding, so the higher MAD reserve penalty does not affect the rest of RTO LMP. In scenario C, there is a reserve shortage for both primary and synchronized reserves in both MAD and RTO Reserve Zones and a violated transmission constraint that affects the marginal congestion costs in the system marginal price.

In scenario C, the sum of the reserve and transmission constraint penalty factors equals $5,450 per MWh, which exceeds $3,750 per MWh, so SMP

111 *See* PJM Operating Agreement, Schedule 1, Section 3.2.3A(d)(ii). The cap on the additive reserve shortage penalty factors in MAD was not reflected in the prior report and the maximum in MAD was therefore overstated. See: *2020 Quarterly State of the Market Report for PJM: January through September*, p. 192.

112 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Rev. 115 (June 1, 2021), 2.8 The Calculation of Locational Marginal Prices (LMPs) During Emergency Procedures.

capping is triggered whether the marginal unit for energy can provide reserves for the MAD zone or only the RTO zone.

In scenario D, with a $1,000 per MWh offer price for the marginal unit for energy, violation of all four reserve penalty factors only triggers SMP capping if the marginal unit for energy can serve the MAD reserve requirement. Scenario E and F show that LMPs can exceed $3,750 per MWh if there is a violated transmission constraint that is not exacerbated by an increase in load at the load weighted reference pricing node, which determines the SMP.[113]

In Scenario F, the energy component of LMP is at its highest level, $2,000 per MWh and there is a reserve shortage for both primary and synchronized reserves in both MAD and RTO Reserve Zones that results in the $1,700 per MWh scarcity adder, and a violated transmission constraint with $2,000 per MWh penalty factor that results in a $5,700 per MWh LMP. The LMPs in Scenario F are not the highest possible LMPs in the PJM energy market under the current rules. If there are multiple violated transmission constraints, the congestion costs contributing to the LMP at a pnode can exceed $2,000 per MWh resulting in LMPs higher than $5,700 per MWh. The extent to which each violated transmission penalty factor affects the LMP at a pnode is directly proportional to the pnode's distribution factor (dfax) with respect to that constraint.

Table 3-75 Additive penalty factors under reserve shortage and transmission constraint violations: Status Quo

		Synchronized Reserve Penalty Factor		Primary Reserve Penalty Factor		Transmission Constraint Penalty Factor in SMP	System Marginal Price		Transmission Constraint Penalty Factor in CLMP	Total LMP	
Scenario	Marginal Unit Offer Price	RTO	MAD	RTO	MAD		MAD Marginal	RTO Marginal		MAD Marginal	RTO Marginal
A	$50	$850	$0	$0	$0	$0	$900	$900	$0	$900	$900
B	$50	$850	$850	$850	$850	$0	$3,450	$1,750	$0	$3,450	$1,750
C	$50	$850	$850	$850	$850	$2,000	$3,750	$3,750	$0	$3,750	$3,750
D	$1,000	$850	$850	$850	$850	$0	$3,750	$2,700	$0	$3,750	$2,700
E	$1,000	$850	$850	$850	$850	$2,000	$3,750	$3,750	$2,000	$5,750	$5,750
F	$2,000	$850	$850	$850	$850	$2,000	$3,750	$3,750	$2,000	$5,750	$5,750

Changes to the ORDC, approved by FERC and planned for implementation in 2022, will increase the price for reserve quantities less than the reserve requirement to $2,000 per MWh.[114] For each reserve quantity greater than the reserve requirement, PJM will multiply an assumed probability of a reserve shortage, based on historic forecast error, by $2,000 per MWh, creating an extended downward sloping ORDC. The extended ORDC is an administratively determined reserve price that will be added to LMP, as a scarcity pricing adder, even when no shortage exists. The $2,000 per MWh price is unjustified because the highest possible energy offer under most circumstances is only $1,000 per MWh. Only in the unusual circumstance when short run marginal costs exceed $1,000 per MWh is a higher ORDC price justified. When energy offers exceed $1,000 per MWh, they have to be verified and preapproved by PJM and cannot exceed $2,000 per MWh, to be eligible to set LMP in the PJM energy market.

The highest possible scarcity adder increases under the planned changes to the ORDC. The highest possible scarcity adder will be $10,000 per MWh, which is the $2,000 per MWh price times five. The five products are the synchronized and nonsynchronized reserve products for RTO and MAD Zones plus a new secondary 30 minute reserve product for the RTO Zone.

Table 3-76 shows example scenarios, under the ORDCs planned for implementation in 2022, with combinations of energy offers, reserve shortage penalty factors and transmission constraint penalty factors that can add up to produce LMPs at sample pnodes in the MAD Reserve Subzone and outside the MAD Reserve Subzone. In scenario B, there is a reserve shortage for both primary and synchronized reserves in both the MAD and RTO Reserve Zones and a reserve shortage for secondary reserve in the RTO Zone that results in the $10,000 per MWh scarcity adder in MAD. The full $10,000 per MWh scarcity adder would apply any time PJM

113 The impact of the transmission constraint penalty factor at a pnode depends on its distribution factor (dfax) with respect to the constraint. The scenarios here assume a single violated transmission constraint with dfax of 1.0. If there are multiple violated transmission constraints, the total impact at a pnode is the sum of the product of transmission constraint penalty factors and distribution factors.

114 See 171 FERC ¶ 61,153 (2020), *order on reh'g*, 173 FERC ¶ 61,123 (2020).

initiates a manual load dump action or voltage reduction action. In scenario C, there is a reserve shortage for both primary and synchronized reserves in both the MAD and RTO Reserve Zones, a reserve shortage for secondary reserve in the RTO Zone, that results in the $10,000 per MWh scarcity adder, and a violated transmission constraint with a $2,000 per MWh penalty factor that results in a $12,050 per MWh LMP at a pnode in MAD.[115]

In Scenario E, the Energy Component of LMP is at its highest level, $2,000 per MWh and there is a reserve shortage for both primary and synchronized reserves in both MAD and RTO Reserve Zones and a secondary reserve shortage, resulting in the $10,000 per MWh scarcity adder, and a violated transmission constraint with a $2,000 per MWh penalty factor that results in a $14,000 per MWh LMP at a pnode in MAD. The LMPs in Scenario E are not the highest possible LMPs in the PJM energy market under the ORDCs planned for implementation in 2022. If there are multiple violated transmission constraints, the transmission constraint penalty factors' contribution to the LMP at a pnode can exceed $2,000 per MWh resulting in LMPs higher than $14,000 per MWh. The extent to which each violated transmission penalty factor affects the LMP at a pnode is directly proportional to the pnode's distribution factor (dfax) with respect to that constraint.

Table 3-76 Additive penalty factors under shortage conditions and transmission constraint violations

Scenario	Energy Component of LMP	Synchronized Reserve Penalty Factor		Primary Reserve Penalty Factor		Secondary Reserve Penalty Factor	Transmission Constraint Penalty Factor	Total LMP in MAD	Total LMP outside MAD
		RTO	MAD	RTO	MAD	RTO			
A	$50	$2,000	$200	$200	$200	$0	$0	$2,650	$2,250
B	$50	$2,000	$2,000	$2,000	$2,000	$2,000	$0	$10,050	$6,050
C	$50	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000	$12,050	$8,050
D	$1,000	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000	$13,000	$9,000
E	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000	$14,000	$10,000

115 The impact of the transmission constraint penalty factor at a pnode depends on its distribution factor (dfax) with respect to the constraint. The scenarios here assume a single violated transmission constraint with dfax of 1.0. If there are multiple violated transmission constraints, the total impact at a pnode is sum of the product of transmission constraint penalty factors and distribution factors.

Operator Actions

Actions taken by PJM operators to maintain reliability, such as committing more reserves than required, may suppress reserve prices. The need to commit more reserves could instead be directly reflected in the ORDC when operational issues arise, allowing the market to efficiently account for the reliability commitment in the energy and reserves markets. Instead, the new ORDC will be inflated at all times based on average historical forecast error that may or may not have resulted in operator actions to commit additional reserves.

PJM plans to implement the new extended downward sloping ORDCs beginning October 1, 2022. PJM calculated ORDCs for each reserve product for a 4 hour time block in an operating day, for each of the four seasons. This results in 24 different ORDCs for each product in a delivery year.[116] These ORDCs were calculated using the reserve penalty factor ($2,000 per MWh) and the probability of reserves being below the minimum reserve requirement (PBMRR) at each quantity above the minimum reserve requirement (MRR). For synchronized reserves and primary reserves, the PBMRR is calculated using the 30 minute look ahead uncertainties associated with the load forecast error, the solar generation forecast error, the wind generation forecast error, and the generation forced outages that occurred in 30 minute look ahead windows of the past three years. For the new secondary reserve product, the PBMRR is calculated using the 60 minute look ahead uncertainties associated with the load forecast error, the solar generation forecast error, the wind generation forecast error, and the generation forced outages that occurred in the 60 minute look ahead windows of the past three years.

In the real-time energy market, PJM executes an RT SCED case for every five minute target time approximately 14 minutes prior to the target time. The forecasts for the target time used in RT SCED, including load, solar generation and wind generation are generated just before the RT SCED case is executed, approximately fifteen minutes prior to the target time. Beginning

116 PJM published the ORDCs for all the reserve products to be used beginning May 1, 2022, which can be accessed at: <https://www.pjm.com/markets-and-operations/ancillary-services>.

November 1, 2021, PJM plans to implement changes that would result in executing RT SCED approximately ten minutes prior to the target time. Under this implementation, the look ahead period of the forecasts and generation data used in RT SCED will be reduced to ten minutes. Generally, the longer the look ahead period for a target time, the greater the forecast errors. Using thirty minute forecast errors to determine the quantity of reserves to procure in the ORDCs will inflate the actual uncertainty in the inputs to RT SCED. This will further inflate the already overstated ORDC price levels for quantities beyond the MRR and LMPs. Use of 30 minute forecast errors is not consistent with PJM's logic. The MMU recommends, if PJM implements extended downward sloping ORDCs, that PJM calculate the probability of reserves falling below the minimum reserve requirement (MRR) based on ten minute rather than 30 minute forecast error, and on forced outages in the ten minute rather than the 30 minute look ahead window to model the uncertainty in the inputs to RT SCED.

Locational Reserve Requirements

In addition to the construction of the operating reserve demand curves to reflect the value of maintaining reserves and avoiding a loss of load event, the modeling of reserve requirements should reflect locational needs and should price operator actions to, for example, commit more reserves when specific needs arise.

The current operating reserve demand curves are modeled for reserve requirements for the RTO level (RTO Reserve Zone) and for the Mid-Atlantic and Dominion region (MAD Subzone). This was a result of historical congestion patterns where limits to transmission capacity to deliver power from outside the MAD Subzone into the MAD Subzone necessitated maintaining reserves in the MAD area to respond to disturbances within the subzone. On most days, the MAD Subzone is no longer relevant. PJM may need to maintain or operate resources in other local areas to maintain local reliability. Currently, these units are committed out of market for reliability reasons, or the reserve need is modeled as an artificial closed loop interface with limited deliverability modeled inside the closed loop from resources located outside. The value of operating these resources, including generators that are manually committed for reliability and demand resources that may be dispatched inside a closed loop, is not correctly reflected in prices. A more efficient way to reflect these requirements would be to have locational reserve requirements that are adjusted based on PJM forecasts and reliability studies.

Pricing During Synchronized Reserve Events

Synchronized reserves are deployed when PJM declares a synchronized reserve event, also known as a spinning event. Currently, spinning events are triggered by an all call message to the system requesting all online generation units to increase their energy output, regardless of whether a unit cleared for synchronized reserves. This deployment mechanism is used regardless of the actual MW needed to recover the Area Control Error (ACE) to zero or to the pre-event levels. Generally, the cause of the spinning event is a unit trip. Occasionally, PJM also declares spinning events to recover ACE when generators do not follow dispatch instructions to increase output. The response solicited through the all call message during a spinning event is much greater than the MW lost and MW needed to recover the ACE. This results in an overshoot of the ACE to positive values beyond the target range. There is currently no mechanism for PJM to selectively load synchronized reserves in proportion to the MW needed to recover ACE to zero or the pre-event levels, even though the PJM market rules allow PJM to load a proportion of reserves. While the all-call message signals resources to increase their output, the approved SCED cases are solved with the reserve requirement intact, which dispatches the system to meet the load and reserve requirements ten to fourteen minutes into the future. This results in a discrepancy between the operational need during a spinning event, and the RT SCED solutions. PJM's instruction to generators is to ignore the dispatch signals sent by RT SCED, and instead continue to ramp their units up until the spin event ends. Since the LMPs do not reflect the need for the generators to ramp up their resources, PJM currently pays a $50 per MWh premium to all resources, except Tier 2 cleared resources, that increase their output in response to a spinning event.

Under the reserve market enhancements that are planned for October 2022, all synchronized reserves are treated as a uniform product and paid the market clearing price for synchronized reserves. All synchronized reserves are also assessed a penalty for nonperformance during the synchronized reserve events. In order to ensure a controlled recovery of ACE after disturbances, PJM needs a mechanism to deploy a subset of the resources that are clearing and are being compensated for synchronized reserves. This mechanism will be most efficient if the resources that are deployed and are subject to performance evaluation for their response are the resources selected to increase their output, instead of dispatching all PJM generation resources.

While PJM recovers from a disturbance during a spinning event, PJM should also adjust the operating reserve demand curve (ORDC) for synchronized reserves to ensure that RT SCED does not have a competing objective of immediately replacing reserves that have been paid for, and are being used for their intended purpose. Without such an adjustment, RT SCED will have to depend on resources that are not deemed to be eligible for clearing as synchronized reserves to aid the recovery of ACE. Without such an adjustment, the prices will be artificially inflated, potentially triggering shortage pricing, during the times when reserves are used for their intended purpose.

Reserve Shortages in 2021

Reserve Shortage in Real-Time SCED

The MMU analyzed the RT SCED solutions to determine how many of the five minute target time RT SCED solutions indicated a shortage of any of the reserve products (synchronized reserve and primary reserve at RTO Reserve Zone and MAD Reserve Subzone), when multiple solutions indicated shortage of reserves, and how many of these resulted in shortage prices in LPC. For reliability reasons, and to maintain reserves to comply with NERC standards, reserves are considered short if the quantity (MW) of reserves dispatched by RT SCED for a five minute interval is less than the minimum reserve requirement (MRR). To trigger shortage pricing, reserves are considered short if the quantity (MW) of reserves dispatched by RT SCED for a five minute interval is less than the extended reserve requirement.

Until June 2, 2021, PJM generally solved one RT SCED case with three solutions per case, for each five minute target time.[117] [118] On June 3, 2021, PJM updated RT SCED to solve two additional scenarios, or a total of five solutions per case. In the first nine months of 2021, the frequency with which RT SCED solutions were approved increased to one solution per five minute interval. This approval frequency increased the proportion of approved SCED solutions that are reflected in LMPs. However, the process of selecting the SCED solution to approve, among the solutions available to PJM operators, is subjective and is not based on clearly defined criteria. The criteria are especially important when only some of the SCED solutions reflects shortage pricing, and the rest of the solutions do not.

The MMU analyzed the target times for which one or more RT SCED case solutions indicated a shortage of one or more reserve products. Table 3-77 shows, for each month of 2020 and the first nine months of 2021, the total number of target times, the number of target times for which at least one RT SCED solution showed a shortage of reserves, the number of target times for which more than one RT SCED solution showed a shortage of reserves, and the number of five minute pricing intervals for which the LPC solution showed a shortage of reserves. Table 3-77 shows that, in the first nine months of 2021, 2,735 target times, or 3.5 percent of all five minute target times, had at least one RT SCED solution showing a shortage of reserves, and 737 target times, or 0.9 percent of all five minute target times, had more than one RT SCED solution showing a shortage of reserves. In the first nine months of 2020, there were 1,143 target times, or 1.4 percent of all five minute target times, that had at least one RT SCED solution showing a shortage of reserves, and 416 target times, or 0.5 percent of all five minute target times, that had more than one RT SCED solution showing a shortage of reserves.

117 A case is executed when it begins to solve. Most but not all cases are solved. RT SCED cases take about one to two minutes to solve.
118 PJM updated the RT SCED execution frequency to solve one case for each five minute target time beginning June 22, 2020. PJM dispatchers may solve additional cases at their discretion.

Table 3-77 Five minute SCED target times and pricing intervals with shortage: January 2020 through September 2021

Year, Month	Number of Five Minute Intervals	Number of Target Times With At Least One SCED Solution Short of Reserves	Percent Target Times With At Least One SCED Solution Short of Reserves	Number of Target Times With Multiple SCED Solutions Short of Reserves	Percent Target Times With Multiple SCED Solutions Short of Reserves	Number of Five Minute Intervals With Shortage Prices in LPC	Percent RT SCED Target Times With Reserve Shortage With Shortage Prices in LPC
2020 Jan	8,928	172	1.9%	89	1.0%	0	0.0%
2020 Feb	8,352	94	1.1%	44	0.5%	0	0.0%
2020 Mar	8,916	173	1.9%	66	0.7%	0	0.0%
2020 Apr	8,640	208	2.4%	99	1.1%	2	1.0%
2020 May	8,928	113	1.3%	36	0.4%	0	0.0%
2020 Jun	8,640	114	1.3%	30	0.3%	0	0.0%
2020 Jul	8,928	110	1.2%	17	0.2%	0	0.0%
2020 Aug	8,928	95	1.1%	14	0.2%	0	0.0%
2020 Sep	8,640	64	0.7%	21	0.2%	0	0.0%
2020 Oct	8,928	327	3.7%	91	1.0%	3	0.9%
2020 Nov	8,652	181	2.1%	44	0.5%	3	1.7%
2020 Dec	8,928	168	1.9%	41	0.5%	1	0.6%
2020 Total	105,408	1,819	1.7%	592	0.6%	9	0.5%
2021 Jan	8,928	114	1.3%	22	0.2%	0	0.0%
2021 Feb	8,064	108	1.3%	28	0.3%	0	0.0%
2021 Mar	8,916	198	2.2%	46	0.5%	4	2.0%
2021 Apr	8,640	130	1.5%	24	0.3%	0	0.0%
2021 May	8,928	235	2.6%	48	0.5%	5	2.1%
2021 Jun	8,640	516	6.0%	165	1.9%	1	0.2%
2021Jul	8,928	460	5.2%	104	1.2%	0	0.0%
2021 Aug	8,928	429	4.8%	131	1.5%	7	1.6%
2021 Sep	8,640	545	6.3%	169	2.0%	2	0.4%
2021 Total	78,612	2,735	3.5%	737	0.9%	19	0.7%

In the first nine months of 2021, there were 19 five minute intervals with shortage pricing, while there were 737 five minute target times for which multiple RT SCED solutions showed a shortage of reserves. In the first nine months of 2020, there were two five minute intervals with shortage pricing, while 416 five minute target times for which multiple RT SCED solutions showed a shortage of reserves. Clear criteria for approval of shortage cases are needed.

The PJM Real-Time Energy Market produces an efficient outcome only when prices are allowed to reflect the fundamental supply and demand conditions in the market in real time. While it is appropriate for operators to ensure that cases use data that reflect the actual state of the system, it is essential that operator discretion not extend beyond what is necessary and that operator discretion not prevent shortage pricing when there are shortage conditions or implement shortage pricing when there are no shortage conditions. This is a critical issue now that PJM settles all real-time energy transactions on a five minute basis using the prices calculated by LPC. The MMU recommends that PJM define clear criteria for operator approval of RT SCED cases, including shortage cases that are used to send dispatch signals to resources, and for pricing, to minimize discretion. A rule based approach is essential for defining how LMPs are determined so that all market participants can be confident that energy market pricing is efficient.

Shortage Pricing Intervals in LPC

There were 19 five minute intervals with shortage pricing in the first nine months of 2021, compared to two intervals in the first nine months of 2020, in PJM. PJM implemented fast start pricing on September 1, 2021. This could result in differences in reserve shortages in the dispatch run and the pricing run. In September 2021, there were two five minute intervals with shortage pricing, and there were no differences in the shortage pricing results from the dispatch and pricing run during these two intervals. Table 3-78 shows the extended synchronized reserve requirement, the total synchronized reserves, the synchronized reserve shortage, and the synchronized reserve clearing prices for the RTO Reserve Zone during the 19 intervals with shortage pricing due to synchronized reserve shortage. Table 3-79 shows the extended synchronized reserve requirement, the total synchronized reserves, the synchronized reserve shortage, and the synchronized reserve clearing prices for the MAD Reserve Subzone during the 19 intervals with shortage pricing due to synchronized reserve shortage. Table 3-80 shows the extended primary reserve requirement, the total primary reserves, the primary reserve shortage, and the primary reserve clearing prices for the RTO Reserve Zone during the six intervals with shortage pricing due to primary reserve shortage. Table 3-81 shows the extended primary reserve requirement, the total primary reserves, the primary reserve shortage, and the primary reserve clearing prices for the MAD Reserve Subzone during the five intervals with shortage pricing due to primary reserve shortage.

PJM enforces an RTO wide reserve requirement and a supplemental reserve requirement for the MAD region. The MAD Reserve Subzone is nested within the RTO Reserve Zone. Resources located in the MAD Reserve Subzone can simultaneously satisfy the synchronized reserve requirement of the RTO Reserve Zone and the synchronized reserve requirement of the MAD Reserve Subzone. Resources located outside the MAD Reserve Subzone can satisfy the synchronized reserve requirement of the RTO Reserve Zone, and subject to transfer limits defined by transmission constraints, satisfy the reserve requirement of the MAD Subzone. The synchronized reserve clearing price of the RTO Reserve Zone is set by the shadow price of the binding reserve requirement constraint of the RTO Reserve Zone.[119] The synchronized reserve clearing price of the MAD Reserve Subzone, nested within the RTO Reserve Zone, is set by the sum of the shadow prices of the binding reserve requirement constraint of the RTO Reserve Zone and the shadow price of the binding reserve requirement constraint of the MAD Reserve Subzone.

In all 19 intervals in the first nine months of 2021 with shortage pricing, both the RTO Zone and the MAD Subzone cleared with synchronized reserves less than their extended requirement. In six out of the 19 intervals, the synchronized reserves in the RTO Zone were short of the minimum reserve requirement, resulting in an $850 per MWh penalty factor. In 13 out of the 19 intervals, the synchronized reserves in the RTO Zone were greater than the minimum reserve requirement but short of the extended reserve requirement (minimum reserve requirement plus 190 MW), resulting in a $300 per MWh penalty factor. The clearing price for synchronized reserves in the RTO Zone is the sum of the shadow prices of the synchronized reserve constraint for the RTO Zone and the primary reserve constraint for the RTO Zone. The clearing price for synchronized reserves in the MAD Subzone is the sum of the shadow prices of the synchronized reserve constraints for the RTO Zone and MAD Subzone and the shadow prices of the primary reserve constraints in the RTO and MAD Subzone.

119 If the reserve requirement cannot be met by the resources located within the reserve zone, the shadow price of the reserve requirement is set by the applicable operating reserve demand curve.

Table 3-78 RTO synchronized reserve shortage intervals: January through September, 2021[120]

	Pricing Run				Dispatch Run			
Interval (EPT)	RTO Extended Synchronized Reserve Requirement (MW)	Total RTO Synchronized Reserves (MW)	RTO Synchronized Reserve Shortage (MW)	RTO Synchronized Reserve Clearing Price ($/MWh)	RTO Extended Synchronized Reserve Requirement (MW)	Total RTO Synchronized Reserves (MW)	RTO Synchronized Reserve Shortage (MW)	RTO Synchronized Reserve Clearing Price ($/MWh)
02-Mar-21 06:30	1,835.0	1,305.6	529.4	$1,700.0				
17-Mar-21 10:10	1,859.0	1,452.1	406.9	$1,150.0				
22-Mar-21 19:45	1,786.0	1,256.5	529.5	$1,700.0				
22-Mar-21 19:50	1,783.0	1,422.9	360.1	$1,150.0				
07-May-21 06:30	1,812.0	1,786.5	25.5	$300.0				
19-May-21 17:10	1,832.0	1,812.8	19.2	$368.1				
19-May-21 17:15	1,829.0	1,672.4	156.6	$398.4				
26-May-21 10:25	1,817.0	1,682.5	134.5	$300.0				
26-May-21 10:30	1,817.0	1,682.5	134.5	$300.0				
02-Jun-21 17:00	1,826.0	1,691.3	134.7	$300.0				
20-Aug-21 16:15	1,773.0	1,583.0	190.0	$850.0				
20-Aug-21 16:20	1,773.0	1,583.0	190.0	$850.0				
20-Aug-21 18:00	1,780.0	1,598.5	181.5	$416.2				
23-Aug-21 16:50	1,780.0	1,666.2	113.8	$300.0				
23-Aug-21 16:55	1,776.0	1,670.4	105.6	$300.0				
23-Aug-21 17:00	1,777.0	1,653.5	123.5	$300.0				
23-Aug-21 17:05	1,777.0	1,653.5	123.5	$300.0				
27-Sep-21 17:00	1,816.0	1,695.4	120.6	$600.0	1,816.0	1,695.4	120.6	$600.0
27-Sep-21 17:05	1,816.0	1,695.4	120.6	$600.0	1,816.0	1,695.4	120.6	$600.0

120 Prior to September 1, 2021, there were no separate dispatch and pricing runs, and the single solution did not incorporate fast start pricing. Beginning September 1, 2021, the LMPs are the output from the pricing run that incorporates fast start pricing.

Table 3-79 MAD synchronized reserve shortage intervals: January through September, 2021[121]

	Pricing Run				Dispatch Run			
Interval (EPT)	MAD Extended Synchronized Reserve Requirement (MW)	Total MAD Synchronized Reserves (MW)	MAD Synchronized Reserve Shortage (MW)	MAD Synchronized Reserve Clearing Price ($/MWh)	MAD Extended Synchronized Reserve Requirement (MW)	Total MAD Synchronized Reserves (MW)	MAD Synchronized Reserve Shortage (MW)	MAD Synchronized Reserve Clearing Price ($/MWh)
02-Mar-21 06:30	1,835.0	1,557.5	277.5	$1,700.0				
17-Mar-21 10:10	1,859.0	1,452.1	406.9	$1,700.0				
22-Mar-21 19:45	1,786.0	1,256.5	529.5	$1,700.0				
22-Mar-21 19:50	1,783.0	1,422.9	360.1	$1,700.0				
07-May-21 06:30	1,812.0	1,786.5	25.5	$600.0				
19-May-21 17:10	1,832.0	1,812.8	19.2	$668.1				
19-May-21 17:15	1,829.0	1,672.4	156.6	$698.4				
26-May-21 10:25	1,817.0	1,682.5	134.5	$600.0				
26-May-21 10:30	1,817.0	1,682.5	134.5	$600.0				
02-Jun-21 17:00	1,826.0	1,691.3	134.7	$600.0				
20-Aug-21 16:15	1,773.0	1,583.0	190.0	$1,573.6				
20-Aug-21 16:20	1,773.0	1,583.0	190.0	$1,544.1				
20-Aug-21 18:00	1,780.0	1,598.5	181.5	$716.2				
23-Aug-21 16:50	1,780.0	1,666.2	113.8	$600.0				
23-Aug-21 16:55	1,776.0	1,670.4	105.6	$600.0				
23-Aug-21 17:00	1,777.0	1,653.5	123.5	$600.0				
23-Aug-21 17:05	1,777.0	1,653.5	123.5	$600.0				
27-Sep-21 17:00	1,816.0	1,695.4	120.6	$1,200.0	1,816.0	1,695.4	120.6	$1,200.0
27-Sep-21 17:05	1,816.0	1,695.4	120.6	$1,200.0	1,816.0	1,695.4	120.6	$1,200.0

Table 3-80 RTO primary reserve shortage intervals: January through September, 2021[122]

	Pricing Run				Dispatch Run			
Interval (EPT)	RTO Extended Primary Reserve Requirement (MW)	Total RTO Primary Reserves (MW)	RTO Primary Reserve Shortage (MW)	RTO Primary Reserve Clearing Price ($/MWh)	RTO Extended Primary Reserve Requirement (MW)	Total RTO Primary Reserves (MW)	RTO Primary Reserve Shortage (MW)	RTO Primary Reserve Clearing Price ($/MWh)
02-Mar-21 06:30	2,657.5	2,405.6	251.9	$850.0				
17-Mar-21 10:10	2,693.5	2,536.1	157.4	$300.0				
22-Mar-21 19:45	2,584.0	2,357.7	226.3	$850.0				
22-Mar-21 19:50	2,579.5	2,406.9	172.6	$300.0				
27-Sep-21 17:00	2,629.0	2,530.9	98.1	$300.0	2,629.0	2,530.9	98.1	$300.0
27-Sep-21 17:05	2,629.0	2,530.9	98.1	$300.0	2,629.0	2,530.9	98.1	$300.0

121 Prior to September 1, 2021, there were no separate dispatch and pricing runs, and the single solution did not incorporate fast start pricing. Beginning September 1, 2021, the LMPs are the output from the pricing run that incorporates fast start pricing.
122 Prior to September 1, 2021, there were no separate dispatch and pricing runs, and the single solution did not incorporate fast start pricing. Beginning September 1, 2021, the LMPs are the output from the pricing run that incorporates fast start pricing.

Table 3-81 MAD primary reserve shortage intervals: January through September, 2021[123]

	Pricing Run				Dispatch Run			
Interval (EPT)	MAD Extended Primary Reserve Requirement (MW)	Total MAD Primary Reserves (MW)	MAD Primary Reserve Shortage (MW)	MAD Primary Reserve Clearing Price ($/MWh)	MAD Extended Primary Reserve Requirement (MW)	Total MAD Primary Reserves (MW)	MAD Primary Reserve Shortage (MW)	MAD Primary Reserve Clearing Price ($/MWh)
17-Mar-21 10:10	2,693.5	2,536.1	157.4	$300.0				
22-Mar-21 19:45	2,584.0	2,357.7	226.3	$850.0				
22-Mar-21 19:50	2,579.5	2,406.9	172.6	$600.0				
27-Sep-21 17:00	2,629.0	2,530.9	98.1	$600.0	2,629.0	2,530.9	98.1	$600.0
27-Sep-21 17:05	2,629.0	2,530.9	98.1	$600.0	2,629.0	2,530.9	98.1	$600.0

On March 17, 2021, for the interval beginning 1010 EPT, both the RTO and MAD primary reserves were short of the extended requirements by 157.4 MW. The penalty factor for each reserve constraint violation was $300 per MWh. On March 22, 2021, for the interval beginning 1945 EPT, both the RTO and MAD primary reserves were short of the extended requirements by 226.3 MW. The penalty factor for each reserve constraint violation was $850 per MWh. Generally, the market clearing price (MCP) for primary reserves in the MAD Subzone will equal the sum of the penalty factor for the reserve requirement constraint of the RTO Reserve Zone and the penalty factor for the reserve requirement constraint of the MAD Reserve Subzone. Using this logic, the MCPs for primary reserves in the MAD Subzone should have been $600 per MWh on March 17, 2021, at 1010 EPT, and $1,700 per MWh on March 22, 2021, at 1945 EPT. However, the MCPs for primary reserves for the MAD Subzone were $300 per MWh and $850 per MWh. This occurred because the MAD primary reserve requirement constraint was relaxed for both these intervals, resulting in the shadow price for the MAD primary reserve constraint equal to $0 per MWh. This is a result of the application of PJM's System Marginal Price (SMP) capping logic. The PJM tariff caps the MCP for primary reserve at one times the nonsynchronized reserve penalty factor for each zone or subzone, and caps the MCP for synchronized reserve at the sum of the penalty factor for synchronized reserve and penalty factor for nonsynchronized reserve, but the PJM tariff does not specify a cap on the system marginal price, or LMPs.[124]

123 Prior to September 1, 2021, there were no separate dispatch and pricing runs, and the single solution did not incorporate fast start pricing. Beginning September 1, 2021, the LMPs are the output from the pricing run that incorporates fast start pricing.
124 OA Schedule 1, Section 3.2.3A(d) and Section 3.2.3A.001(c).

System Marginal Price Cap

In the PJM Real Time Energy Market, the SMP is capped at $3,750 per MWh. This cap is the result of the Energy Offer Cap ($2,000 per MWh), the Synchronous Reserve Penalty Factor from the first step on the demand curve ($850 per MWh), the Primary Reserve Penalty Factor from the first step on the demand curve ($850 per MWh) and a threshold ($50 per MWh). The Operating Agreement states that only two, of the four, reserve penalty factors may be applied.

If the SMP would otherwise exceed $3,750 per MWh, PJM solves the SCED optimization by progressively relaxing reserve requirement constraints until the SMP falls below the cap. For instance, if the original SMP is above $3,750, PJM would solve the SCED optimization by disabling the subzone (MAD) primary reserve requirement constraint. If the SMP from the relaxed SCED optimization is still above $3,750, PJM would solve the SCED optimization by disabling subzone (MAD) primary and synchronized reserve requirement constraints. If the relaxed SCED optimization is still above $3,750, PJM would solve the SCED optimization by disabling subzone (MAD) primary and synchronized reserve requirement constraints and the RTO primary reserve constraint.

Since 2018, the SMP has been capped in 95 SCED solutions, of which four SCED solutions were approved and used in the LPC to set the five minute LMPs in the PJM Real-Time Energy Market.

Table 3-82 shows the shadow price, MCP and SMP for all reserve constraints for SCED cases that were solved using PJM's SMP capping logic and set the prices in the PJM Real-Time Energy Market. The shadow price of a reserve requirement constraint is the marginal cost of satisfying an increase in the reserve requirement. The shadow price equals the penalty factor of the reserve requirement constraint if the total cleared reserves are below the requirement.

Table 3-83 shows the components of SMP for the five minute intervals that used SMP capping logic since 2018. The SMP is the marginal cost of satisfying an increase in load at the load weighted reference bus. That marginal cost includes the marginal cost of generation, the marginal cost of congestion and the marginal cost of reserves. By definition, all of these marginal costs are included in the marginal energy component of LMP at the load weighted reference bus, which is referred to as the system marginal price (SMP). The marginal cost of generation is the incremental offer price of the marginal generation resource adjusted for the marginal cost of losses. The marginal cost of congestion reflects the marginal cost of the unit required to meet the load if there are transmission constraints, including transmission penalty factors when relevant. If the marginal unit is also providing reserves, the marginal cost of reserves reflects the marginal cost incurred to meet the reserve requirement.

The SMP for the five minute interval beginning at 10:10 on March 17, 2021 was $3,653.98 per MWh. The MAD primary reserve constraint was disabled for this interval. Of the $3,653.98 per MWh, the marginal unit's incremental energy cost after accounting for the marginal cost of losses was $17.85 per MWh, the congestion cost was $1,546.98 per MWh and the reserve opportunity cost was $2,086.15 per MWh. The remaining $3.00 is rounding error.[125] The SMP, without the use of the capping logic, would have been at least $3,965.08 per MWh.[126]

The contribution of the transmission penalty factor of a violated transmission constraint to the SMP depends on the location of the marginal units relative to the location of the load weighted reference bus. If the marginal unit is located such that an incremental increase in the load at the load weighted reference bus results in increased flow on the violated transmission constraint, the SMP reflects the positive contribution of the transmission penalty factor. The marginal congestion component, $1,546.98, for the five minute interval beginning at 10:10 on March 17, 2021, includes the contribution of transmission constraint penalty factors of two violated transmission constraints.

125 The final SMP does not precisely match the sum of components due to rounded network parameters such as distribution factors and loss penalty factors used for deriving the components of the SMP. This difference is shown as rounding error.

126 The original SMP shown in the table represents the lower bound of the uncapped SMP. PJM does not report the segment of the disabled reserve constraint. To derive the original SMP, the lowest priced segment that results in the SMP exceeding the cap was used.

Table 3-82 Five minute intervals based on approved SCED cases that used SMP capping logic: January 2018 through September 2021

Five Minute Interval	Reserve Constraint	Disabled	Shadowprice ($/MWh)	MCP ($/MWh)	SMP ($/MWh)
01OCT2019:15:00:00	MAD Primary Reserve	No	$0.00	$300.00	$3,651.02
01OCT2019:15:00:00	MAD Synchronized Reserve	Yes	$0.00	$1,150.00	$3,651.02
01OCT2019:15:00:00	RTO Synchronized Reserve	No	$850.00	$1,150.00	$3,651.02
01OCT2019:15:00:00	RTO Primary Reserve	No	$300.00	$300.00	$3,651.02
13NOV2020:18:00:00	MAD Primary Reserve	Yes	$0.00	$850.00	$3,166.28
13NOV2020:18:00:00	MAD Synchronized Reserve	No	$850.00	$2,550.00	$3,166.28
13NOV2020:18:00:00	RTO Primary Reserve	No	$850.00	$850.00	$3,166.28
13NOV2020:18:00:00	RTO Synchronized Reserve	No	$850.00	$1,700.00	$3,166.28
02MAR2021:06:30:00	MAD Synchronized Reserve	Yes	$0.00	$2,782.22	$2,994.68
02MAR2021:06:30:00	MAD Primary Reserve	No	$149.36	$999.36	$2,994.68
02MAR2021:06:30:00	RTO Primary Reserve	No	$850.00	$850.00	$2,994.68
02MAR2021:06:30:00	RTO Synchronized Reserve	No	$1,782.86	$2,632.86	$2,994.68
17MAR2021:10:10:00	MAD Synchronized Reserve	No	$850.00	$2,000.00	$3,653.98
17MAR2021:10:10:00	RTO Primary Reserve	No	$300.00	$300.00	$3,653.98
17MAR2021:10:10:00	RTO Synchronized Reserve	No	$850.00	$1,150.00	$3,653.98
17MAR2021:10:10:00	MAD Primary Reserve	Yes	$0.00	$300.00	$3,653.98

Table 3-83 Components of SMP for five minute intervals based on approved SCED cases that used SMP capping logic: January 2018 through September 2021

	Lower bound	Components of Final SMP				
Five Minute Interval	of Original SMP	Final SMP	Marginal Cost of Generation	Marginal Cost of Congestion	Marginal Cost of Reserves	Rounding Error
October 01,2019 15:00:00	$3,950.36	$3,651.02	$33.88	$2,436.47	$1,173.81	$6.87
November 13,2020 18:00:00	$4,049.76	$3,166.28	$520.20	$0.00	$2,645.22	$0.86
March 02,2021 06:30:00	$3,891.21	$2,994.68	$30.51	$181.10	$2,780.81	$2.26
March 17,2021 10:10:00	$3,965.08	$3,653.98	$17.85	$1,546.98	$2,086.15	$3.00

The MMU recommends that PJM cease the practice of capping the system marginal price in the RT SCED and instead limit the sum of violated reserve constraint shadow prices used in LPC to $1,700 per MWh.

Accuracy of Reserve Measurement

The definition of a shortage of synchronized and primary reserves is based on the measured and estimated levels of load, generation, interchange, demand response, and reserves from the real-time SCED software. The definition of such shortage also includes discretionary operator inputs to the ASO (Ancillary Service Optimizer) or RT SCED software, such as tier 1 bias or operator load bias. For shortage pricing to be accurate, there must be accurate measurement of real-time reserves. That does not appear to be the case at present in PJM, but there does not appear to be any reason that PJM cannot accurately measure reserves. Without accurate measurement of reserves on a minute by minute basis, system operators cannot know with certainty that there is a shortage condition and a reliable trigger for five minute shortage pricing does not exist. The benefits of five minute shortage pricing are based on the assumption that a shortage can be precisely and transparently defined.[127] PJM cannot accurately measure or price reserves due to the inaccuracy of its generator models. PJM's commitment and dispatch models rely on generator data to properly commit and dispatch generators. Generator data includes offers and parameters. When the models do not properly account for the different generator characteristics, both PJM dispatchers and generators have to make simplifications and assumptions using the tools available. Most of these actions taken by generators and by PJM dispatchers are not transparent. PJM manuals do not provide clarity regarding what actions generators can take when the PJM models and tools do not reflect their operational characteristics and PJM manuals do not provide sufficient clarity regarding the actions PJM dispatchers can take when generators do not follow dispatch.

In the energy and reserve markets, the actions that both generators and PJM dispatchers take have a direct impact on the amount of supply available for energy and reserves and the prices for energy and reserves. These flaws in PJM's models do not allow PJM to accurately calculate the amount of reserves available. PJM does not accurately model discontinuities in generator ramp rates, such as duct burners on combined cycle plants. PJM's generator models do not account for the complexities that may result in generators underperforming their submitted ramp rates. Instead of addressing these complexities through generator modeling improvements, PJM relies on a nontransparent method of adjusting generator parameters, called Degree of Generator Performance (DGP).[128] [129] PJM also fails to accurately model unit starts. The market software does not account for the energy output a resource produces prior to reaching its economic minimum output level, during its soak time.

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

PJM adjusts ramp rates using DGP, deselects specific units from providing reserves, and overrides the dispatch signal to certain units to set the dispatch signal equal to actual resource output. These manual interventions are, at best, rough approximations of the capability of generators and result in an inaccurate measurement of reserves.

Competitive Assessment

Market Structure

Market Concentration

The Herfindahl-Hirschman Index (HHI) concentration ratio is the sum of the squares of the market shares of all firms in a market. Hourly PJM energy market HHIs are based on the real-time energy output of generators adjusted with scheduled imports. Hourly HHIs for the baseload, intermediate and peaking segments of generation supply are based on hourly energy market shares, unadjusted for imports.

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.

128 *See* "PJM Manual 12: Balancing Operations," Rev. 42 (Jan. 27, 2021) Attachment A, P78. "PJM Manual 11: Energy and Ancillary Services Market Operations," does not mention the use of DGP in the market clearing engine.

129 PJM published a whitepaper that defines DGP and describes its use, which can be accessed at <http://www.pjm.com/~/media/etools/oasis/system-information/generation-performance-monitor-and-degree-of-generator-performance-white-paper.ashx> (July 2, 2020).

An aggregate pivotal supplier test is required to accurately measure the ability of incremental resources to exercise market power.

FERC's Merger Policy Statement defines levels of concentration by HHI level. The market is unconcentrated if the market HHI is below 1000, the HHI if there were 10 firms with equal market shares. The market is moderately concentrated if the market HHI is between 1000 and 1800. The market is highly concentrated if the market HHI is greater than 1800, the HHI if there were between five and six firms with equal market shares.[130]

When transmission constraints exist, local markets are created with ownership that is typically significantly more concentrated than the overall energy market. PJM offer capping rules that limit the exercise of local market power were generally effective in preventing the exercise of market power in the first nine months of 2021, although there are issues with the application of market power mitigation for resources whose owners fail the TPS test that permit local market power to be exercised even when mitigation rules are applied. These issues include the lack of a method for consistently determining the cheaper of the cost and price schedules and the lack of rules requiring that cost-based offers equal short run marginal costs.

PJM HHI Results

Hourly HHIs indicate that by FERC standards, the PJM energy market during the first nine months of 2021 was unconcentrated on average (Table 3-84).[131] The fact that the average HHI is in the unconcentrated range and the maximum hourly HHI is in the moderately concentrated range does not mean that the aggregate market was competitive in all hours. It is possible to have pivotal suppliers in the aggregate market even when the HHI level does not indicate a highly concentrated market structure. Given the low responsiveness of consumers to prices (inelastic demand), it is possible to have high markup even when HHI is low. It is possible to have an exercise of market power even when the HHI level does not indicate a highly concentrated market structure.

Table 3-84 Hourly energy market HHI: January through September, 2020 and 2021

By offering supplier	Hourly Market HHI (Jan - Sep, 2020)	Hourly Market HHI (Jan - Sep, 2021)
Average	788	743
Minimum	569	530
Maximum	1166	1114
Highest market share (One hour)	28%	27%
Average of the highest hourly market share	19%	19%
# Hours	6,575	6,551
# Hours HHI > 1800	0	0
% Hours HHI > 1800	0%	0%

Table 3-85 includes HHI values by supply curve segment, including base, intermediate and peaking plants for the first nine months of 2020 and 2021. On average, ownership in the baseload segment was unconcentrated, in the intermediate segment was moderately concentrated, and in the peaking segment was highly concentrated.[132] High concentration levels, particularly in the peaking segment, increase the probability that a generation owner will be pivotal in the aggregate market.

Table 3-85 Generation segment HHI: January through September, 2020 and 2021

	Jan - Sep, 2020			Jan - Sep, 2021		
	Minimum	Average	Maximum	Minimum	Average	Maximum
Base	654	823	1204	621	786	1121
Intermediate	724	1815	6933	574	1420	9838
Peak	629	6400	10000	711	6022	10000

Figure 3-50 shows the total installed capacity (ICAP) MW of units in the baseload, intermediate and peaking segments by fuel source in the first nine months of 2021.[133]

130 See *Inquiry Concerning the Commission's Merger Policy under the Federal Power Act: Policy Statement*, 77 FERC ¶ 61,263 *mimeo* at 80 (1996).
131 The HHI calculations use actual real time settled generation data for each unit in PJM. Each unit's output is assigned to the supplier that is responsible for offering the unit in the energy market.
132 A unit is classified as base load if it runs for 50 percent of hours or more, as intermediate if it runs for less than 50 percent but greater than or equal to 10 percent of hours, and as peak if it runs for less than 10 percent of hours.
133 The installed capacity (ICAP) used for wind and solar units here is their nameplate capacity in MW. In PJM's Capacity Market, the ICAP value of wind and solar units is derated from the nameplate capacity to reflect their effective load carrying capability.

Figure 3-50 Fuel source distribution in unit segments: January through September, 2021[134]

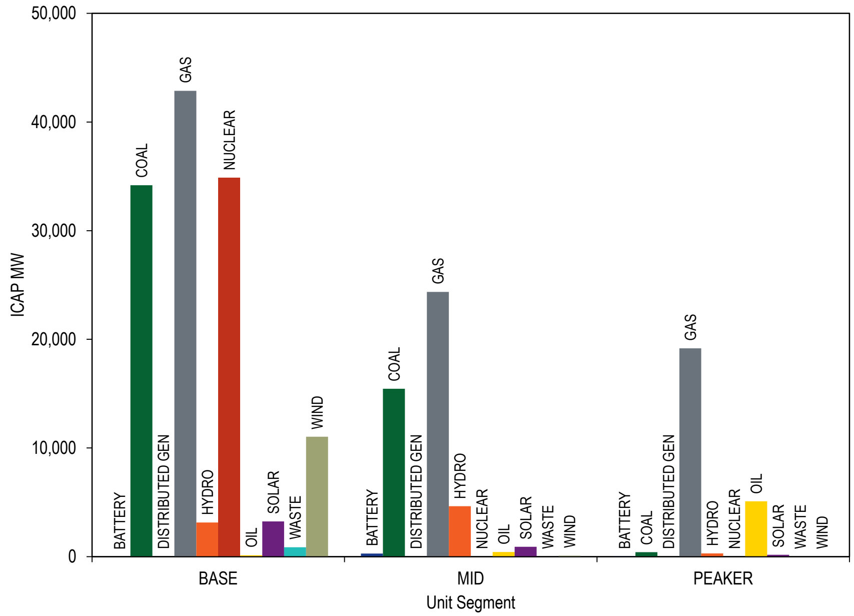


Figure 3-51 Unit segment classification by fuel: January through September, 2017 through 2021

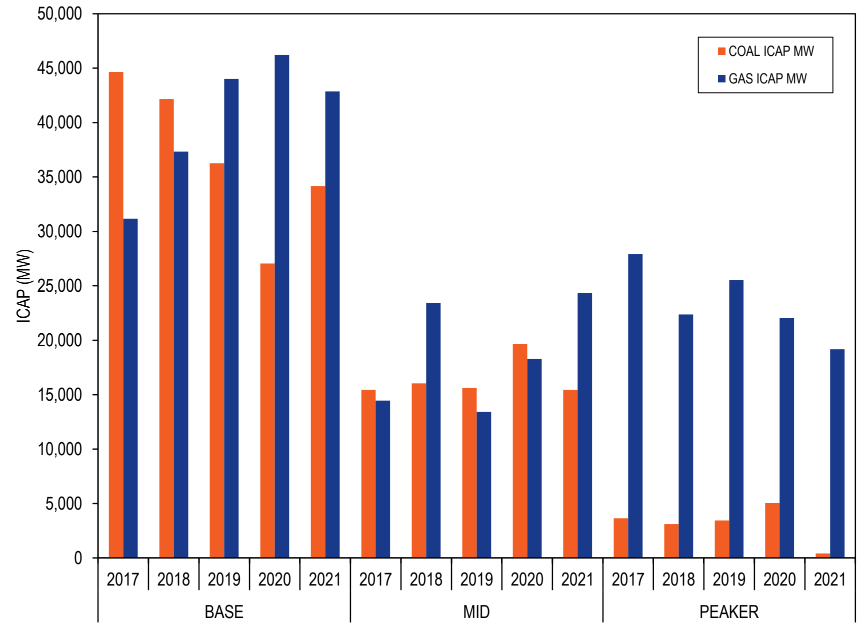
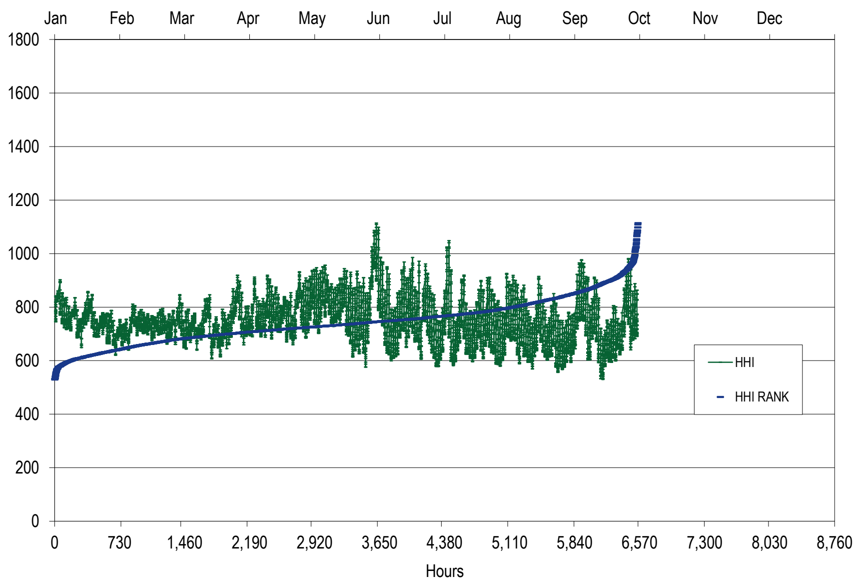


Figure 3-51 shows the ICAP of coal fired and gas fired units in PJM that are classified as baseload, intermediate and peaking in the first nine months from 2017 through 2021. Figure 3-51 shows that the total ICAP of coal fired units in PJM classified as baseload generally decreased from 2017 through 2021, and the total ICAP of gas fired units in PJM classified as baseload generally increased from 2017 through 2021. In 2019, the ICAP of gas fired units classified as baseload exceeded the ICAP of coal fired units classified as baseload for the first time. In the first nine months of 2021, the ICAP of coal fired units classified as baseload increased compared to the first nine months of 2020.

134 The units classified as Distributed Gen are buses within Electric Distribution Companies (EDCs) that are modeled as generation buses to accurately reflect net energy injections from distribution level load buses. The modeling change was the outcome of the Net Energy Metering Task Force stakeholder group in July, 2012. See PJM. "Net Energy Metering Senior Task Force (NEMSTF) 1st Read - Final Report and Proposed Manual Revisions," (June 28, 2012) <http://www.pjm.com/~/media/committees-groups/task-forces/nemstf/postings/20120628-first-read-item-04-nemstf-report-and-proposed-manual-revisions.ashx>.

Figure 3-52 presents the hourly HHI values in chronological order and an HHI duration curve for the first nine months of 2021. The hours when the HHI increased above 1000 all occurred between May 29, 2021 through June 1, 2021, during the Memorial Day weekend and between July 3, 2021 through July 4, 2021, the Independence Day weekend.

Figure 3-52 Hourly energy market HHI: January through September, 2021



Market-Based Rates

Participation in the PJM market using offers that exceed costs requires market-based rate approval from FERC, which reviews the market-based rate authority of PJM market sellers on a triennial schedule to ensure that market sellers do not have market power or that market power is appropriately mitigated. The entire PJM Region is included in the Northeast Region for purposes of the triennial review schedule. The most recent triennial review filing period for the December 1, 2017 through November 30, 2018 study period for nontransmission owning utilities in the Northeast Region was in June 2020. The next triennial review filing period for the December 1, 2020 through November 30, 2021 study period for transmission owners in the Northeast Region will be in December 2022.

With Order No. 861, FERC no longer requires structural market power assessments to determine whether sellers have market power in the PJM markets. Instead, sellers may rely on a rebuttable presumption that market monitoring and market power mitigation are sufficient to ensure competitive market outcomes.[135]

The MMU has recommended since 2015 that changes to the offer capping process for the energy market are needed to ensure effective market power mitigation of units that fail the TPS test. The MMU has found that the capacity market is not competitive because the default Market Seller Offer Cap (MSOC) is inflated due to the use of an inaccurate estimate for the expected number of Performance Assessment Intervals (PAIs).[136] With these results and the supporting evidence, the MMU has challenged the rebuttable presumption of sufficient market power mitigation for the June 2020 triennial review filings by unit generating unit owners in PJM and recommended that conditions limiting sellers to cost-based energy offers and a revised capacity market offer cap be required until improvements are made to the offer capping processes in the energy and capacity markets so that suppliers cannot exercise market power.[137] In the first six months of 2021, FERC issued orders requiring review of the adequacy of the market power mitigation rules and their implementation in the capacity and energy markets.[138] [139]

135 *Refinements to Horizontal Market Power Analysis for Sellers in Certain Regional Transmission Organization and Independent System Operator Markets*, Order No. 861, 168 FERC ¶ 61,040 (2019) ("Order No. 861").
136 See Complaint of the Independent Market Monitor for PJM, Docket No. EL19-47, (February 21, 2019), which can be accessed at <https://www.monitoringanalytics.com/Filings/2019/IMM_Complaint_Docket_No_EL19-XXX_20190221.pdf>.
137 See, e.g., Protest of the Independent Market Monitor for PJM, Docket No. ER10-1556 (August 28, 2020).
138 See 175 FERC ¶ 61,231 (June 17, 2021).
139 See 174 FERC ¶ 61,212 (March 18, 2021).

Merger Reviews

FERC reviews contemplated dispositions, consolidations, acquisitions, and changes in control of jurisdictional generating units and transmission facilities under section 203 of the Federal Power Act to determine whether such transactions are "consistent with the public interest."[140]

FERC applies tests set forth in the 1996 Merger Policy Statement.[141] [142]

The 1996 Merger Policy Statement provides for review of jurisdictional transactions based on "(1) the effect on competition; (2) the effect on rates; and (3) the effect on regulation." FERC adopted the 1992 Department of Justice Guidelines and the Federal Trade Commission Horizontal Merger Guideline (1992 Guidelines) to evaluate the effect on competition. Following the 1992 Guidelines, FERC applies a five step framework, which includes: (1) defining the market; (2) analyzing market concentration; (3) analyzing mitigative effects of new entry; (4) assessing efficiency gains; and (5) assessing viability of the parties without a merger. FERC also evaluates a Competitive Analysis Screen.[143]

The MMU reviews proposed mergers based on analysis of the impact of the merger or acquisition on market power given actual market conditions. The analysis includes use of the three pivotal supplier test results in the real-time energy market. The MMU's review ensures that mergers are evaluated based on their impact on local market power in the PJM energy market using actual observed market conditions, actual binding constraints and actual congestion results. This is in contrast to the typical merger filing that uses predefined local markets rather than the actual local markets. The MMU routinely files comments including such analyses.[144] The MMU has proposed that FERC adopt this approach when evaluating mergers in PJM.[145] FERC has considered the MMU's analysis in reviewing mergers.[146]

The MMU also reviews transactions that involve ownership changes of PJM generation resources that are submitted to the Commission pursuant to section 203 of the Federal Power Act. Table 3-86 shows transactions that involved an entire generation unit or unit owner that were completed in the first nine months of 2021, as reported to the Commission. Table 3-87 shows transactions that involved transfers of partial unit ownership that were completed in the first nine months of 2021, as reported to the Commission.[147]

140 18 U.S.C. § 824b.

141 See Order No. 592, FERC Stats. & Regs. ¶ 31,044 (1996) (1996 Merger Policy Statement), *reconsideration denied*, Order No. 592-A, 79 FERC ¶ 61,321 (1997). See also FPA Section 203 Supplemental Policy Statement, FERC Stats. & Regs. ¶ 31,253 (2007), *order on clarification and reconsideration*, 122 FERC ¶ 61,157 (2008).

142 FERC has an open but inactive docket where the guidelines are under review. See 156 FERC ¶ 61,214 (2016); FERC Docket No. RM16-21-000.

143 In February 2019, in response to 2017 amendments to Section 203 of the Federal Power Act, the Commission issued Order No. 855, implementing a $10,000,000 minimum value for transactions requiring the Commission's review. See 166 FERC ¶ 61,120 (2019)

144 See, e.g., Comments of the Independent Market Monitor for PJM, FERC Docket No. EC14-141-000 (Nov. 10, 2014); Comments of the Independent Market Monitor for PJM, FERC Docket No. EC14-96-000 (July 21, 2014) Comments of the Independent Market Monitor for PJM, FERC Docket No. EC11-83-000 (July 21, 2011); Comments of the Independent Market Monitor for PJM, FERC Docket No. EC14-14 (Dec. 9, 2013); Comments of the Independent Market Monitor for PJM, FERC Docket No. EC14-112-000 (Sept. 15, 2014); Comments of the Independent Market Monitor for PJM, FERC Docket No. EC20-49 (June 1, 2020).

145 See Comments of the Independent Market Monitor for PJM, Docket No. RM16-21 (Dec. 12, 2016).

146 See *Dynegy Inc., et al.*, 150 FERC ¶ 61, 231 (2015); *Exelon Corporation, Constellation Energy Group, Inc.*, 138 FERC ¶ 61,167 (2012); *NRG Energy Holdings, Inc., Edison Mission Energy*, 146 FERC ¶ 61,196 (2014); *see also Analysis of Horizontal Market Power under the Federal Power Act*, 138 FERC ¶ 61,109 (2012).

147 The transaction completion date is based on the notices of consummation submitted to the Commission.

Table 3-86 Completed transfers of entire resources: January through September, 2021

Generator or Generation Owner Name	From	To	Transaction Completion Date	Docket
LES Landfill Units	LES Manager LLC	Energy Power Investment Company	June 10, 2021	EC21-61
Big Sky Wind	Blackrock Inc	Vitol	April 15, 2021	EC21-53
Mount Storm Wind	Castleton Commodities International	Clearway Energy Group LLC	April 23, 2021	EC21-52
PEI Power	Energy Transfer LP	Archaea Holdings, LLC	April 5, 2021	EC21-45
PEI Power	Archaea Holdings, LLC	Rice Acquisition Corp	September 15, 2021	EC21-84

Table 3-87 Completed transfers of partial ownership of resources: January through September, 2021

Generator or Generation Owner Name	From	To	Transaction Completion Date	Docket
Competitive Power Ventures: Fairview (25%), Maryland (25%), Shore (37.5%)	Global Infrastructure Partners	OPC Energy	January 25, 2021	EC21-16
Yards Creek (50%)	JCPL	LS Power Development LLC	March 5, 2021	EC20-65
Hamilton Liberty, Hamilton Patriot (50%)	EIG Management	The Carlyle Group	June 9, 2021	EC21-54
Old Trail Wind Farm (49%)	OMERS Administration Corporation	Algonquin Power & Utilities Corp	June 16, 2021	EC21-78
Calvert Cliffs (49.99 %)	EDF, Inc	Exelon	August 6, 2021	EC20-72

The MMU has also facilitated settlements for mitigation of market power, in cases where market power concerns have been identified.[148] Such mitigation is designed to mitigate behavior over the long term, in addition to or instead of imposing short term asset divestiture requirements.

Aggregate Market Pivotal Supplier Results

Notwithstanding the HHI level, a supplier may have the ability to raise energy market prices. If reliably meeting the PJM system load requires energy from a single supplier, that supplier is pivotal and has monopoly power in the aggregate energy market. If a small number of suppliers are jointly required to meet load, those suppliers are jointly pivotal and have oligopoly power. The number of pivotal suppliers in the energy market is a more precise measure of structural market power than the HHI. The HHI is not a definitive measure of structural market power.

148 See 138 FERC ¶ 61,167 at P 19.

The current market power mitigation rules for the PJM energy market rely on the assumption that the aggregate market includes sufficient competing sellers to ensure competitive market outcomes. With sufficient competition, any attempt to economically or physically withhold generation would not result in higher market prices, because another supplier would replace the generation at a similar price. This assumption requires that the total demand for energy can be met without the supply from any individual supplier or without the supply from a small group of suppliers. This assumption is not always correct, as demonstrated by these results. There are pivotal suppliers in the aggregate energy market.

The existing market power mitigation measures do not address aggregate market power.[149] The MMU is developing an aggregate market power test for the day-ahead and real-time energy markets based on pivotal suppliers and will propose appropriate market power mitigation rules to address aggregate market power.

Day-Ahead Energy Market Aggregate Pivotal Suppliers

To assess the number of pivotal suppliers in the day-ahead energy market, the MMU determined, for each supplier, the MW available for economic commitment that were already running or were available to start between the close of the day-ahead energy market and the peak load hour of the operating day. The available supply is defined as MW offered at a price less than 150 percent of the applicable LMP because supply available at higher prices is not competing to meet the demand for energy.[150] Generating units, import transactions, economic demand response, and INCs, are included for each supplier. Demand is the total MW required by PJM to meet physical

149 One supplier, Exelon, is partially mitigated for aggregate market power through its merger agreement. The agreement is not part of the PJM market rules. See Monitoring Analytics, LLC, Letter attaching Settlement Terms and Conditions, FERC Docket No. EC11-83-000 and Maryland PSC Case No. 9271 (October 11, 2011).

150 Each LMP is scaled by 150 percent to determine the relevant supply, resulting in a different price threshold for each LMP value. The analysis does not solve a redispatch of the PJM market.

load, cleared load bids, export transactions, and DECs. A supplier is pivotal if PJM would require some portion of the supplier's available economic capacity in the peak hour of the operating day in order to meet demand. Suppliers are jointly pivotal if PJM would require some portion of the joint suppliers' available economic capacity in the peak hour of the operating day in order to meet demand.

Figure 3-53 shows the number of days in 2020 and the first nine months of 2021 with one pivotal supplier, two jointly pivotal suppliers, and three jointly pivotal suppliers for the day-ahead energy market. One supplier was singly pivotal on the summer peak days in 2020 and multiple suppliers were singly pivotal on the summer peak days of 2021. One supplier was singly pivotal on February 15, 2021. Two suppliers were jointly pivotal on 128 days in 2020 and on 106 days in the first nine months of 2021. Three suppliers were jointly pivotal on 301 days in 2020 and on 239 days in the first nine months of 2021, despite average HHIs at persistently unconcentrated levels. In 2020 and 2021, the highest levels of aggregate market power occurred in the third quarter, PJM's summer peak load season. Outside the summer months, the frequency of pivotal suppliers increased on high demand days in January 2020 and in February 2021.

Figure 3-53 Days with pivotal suppliers and numbers of pivotal suppliers in the day-ahead energy market by quarter

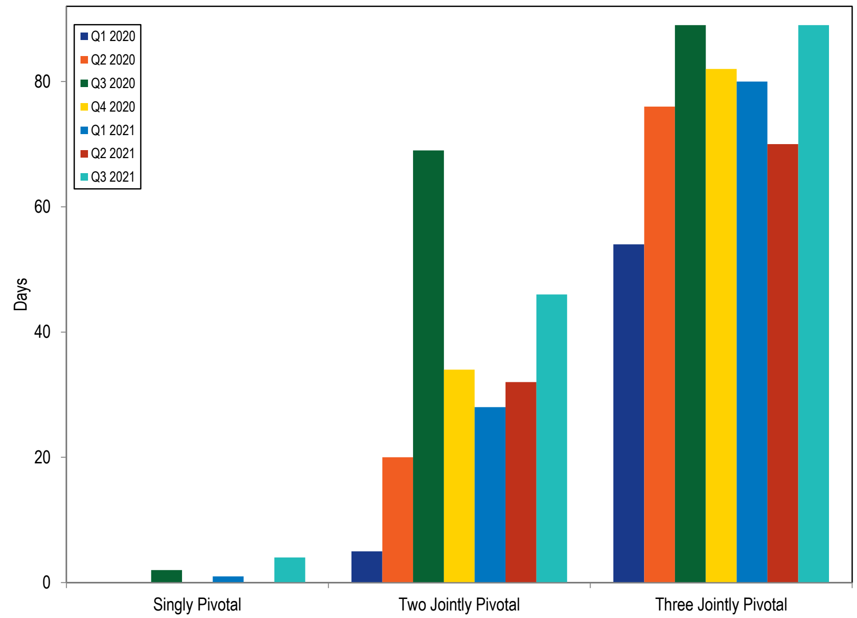


Table 3-88 provides the frequency with which each of the top 10 pivotal suppliers was singly or jointly pivotal for the day-ahead energy market in the first nine months of 2021. The largest pivotal supplier was singly pivotal on four days in the first nine months of 2021. All of the top 10 suppliers were one of two pivotal suppliers on at least 16 days in the first nine months of 2021. All of the top 10 suppliers were one of three pivotal suppliers on at least 147 days in the first nine months of 2021.

Table 3-88 Day-ahead market pivotal supplier frequency: January through September, 2021

Pivotal Supplier Rank	Days Singly Pivotal	Percent of Days	Days Jointly Pivotal with One Other Supplier	Percent of Days	Days Jointly Pivotal with Two Other Suppliers	Percent of Days
1	4	1.5%	102	37.4%	238	87.2%
2	3	1.1%	101	37.0%	238	87.2%
3	1	0.4%	58	21.2%	222	81.3%
4	0	0.0%	80	29.3%	239	87.5%
5	0	0.0%	56	20.5%	230	84.2%
6	0	0.0%	27	9.9%	202	74.0%
7	0	0.0%	23	8.4%	181	66.3%
8	0	0.0%	18	6.6%	176	64.5%
9	0	0.0%	18	6.6%	147	53.8%
10	0	0.0%	16	5.9%	150	54.9%

Market Behavior

Local Market Power

In the PJM energy market, market power mitigation rules currently apply only for local market power. Local market power exists when transmission constraints or reliability issues create local markets that are structurally noncompetitive. If the owners of the units required to solve the constraint or reliability issue are pivotal or jointly pivotal, they have the ability to set the price. Absent market power mitigation, unit owners that submit noncompetitive offers, or offers with inflexible operating parameters, could exercise market power. This could result in LMPs being set at higher than competitive levels, or could result in noncompetitive uplift payments.

The three pivotal supplier (TPS) test is the test for local market power in the energy market.[151] If the TPS test is failed, market power mitigation is applied by offer capping the resources of the owners who have been identified as having local market power. Offer capping is designed to set offers at competitive levels. Competitive offers are defined to be cost-based energy offers. In the PJM energy market, units are required to submit cost-based energy offers, defined by fuel cost policies, and have the option to submit market-based, also called price-based, offers. Units are committed and dispatched on price-based offers, if offered, as the default offer. When a unit that submits both cost-based and price-based offers is mitigated to its cost-based offer by PJM, it is considered offer capped. A unit that submits only cost-based offers, or that requests PJM to dispatch it on its cost-based offer, is not considered offer capped.

Local market power mitigation is implemented in both the day-ahead and real-time energy markets. However, the implementation of the TPS test and offer capping differ in the day-ahead and real-time energy markets.

TPS Test Statistics for Local Market Power

The TPS test in the energy market defines whether one, two or three suppliers are jointly pivotal in a defined local market. The TPS test is applied when the system solution indicates that out of merit resources are needed to relieve a transmission constraint. The TPS test result for a constraint for a specific interval indicates whether a supplier failed or passed the test for that constraint for that interval. A failed test indicates that the resource owner has structural market power.

A metric to describe the number of local markets created by transmission constraints and the applicability of the TPS is the number of hours that each transmission constraint was binding in the real-time energy market over a period, by zone.

In the first nine months of 2021, the 500 kV system, 12 zones, and MISO experienced congestion resulting from one or more constraints binding for 75 or more hours, or resulting from a binding interface constraint (Table 3-89).[152] Table 3-89 shows that the 500 kV system, four zones and MISO experienced congestion resulting from one or more constraints binding for 75 or more hours or resulting from a binding interface constraint in every year from January through September, 2009 through 2021. Three Control Zones did not

151 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>.

152 A constraint is mapped to the 500 kV system if its voltage is 500 kV and it is located in one of the control zones including AECO, BGE, DPL, JCPLC, MEC, PECO, PENELEC, PEPCO, PPL and PSEG. All PJM/MISO reciprocally coordinated flowgates (RCF) are mapped to MISO regardless of the location of the flowgates. All PJM/NYISO RCF are mapped to NYISO as location regardless of the location of the flowgates.

experience congestion resulting from one or more constraints binding for 75 or more hours or resulting from any binding interface constraint in any year from January through September, 2009 through 2021.[153]

Table 3-89 Congestion hours resulting from one or more constraints binding for 75 or more hours or from an interface constraint: January through September, 2009 through 2021

	(Jan - Sep)												
	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
500 kV System	3,421	5,087	4,039	469	2,084	1,504	759	903	863	1,062	2,533	2,325	1,544
ACEC	149	163	234	0	0	0	192	413	0	94	97	0	0
AEP	1,005	1,265	2,452	178	2,018	1,821	1,891	633	469	1,592	595	1,049	1,194
APS	421	1,121	87	89	0	170	451	157	136	184	0	510	0
ATSI	140	0	0	208	68	481	424	1	134	1,470	1	0	0
BGE	127	274	368	1,582	1,192	4,416	6,006	8,506	1,748	2,644	622	6,986	1,660
COMED	784	2,108	1,118	1,808	3,169	1,928	1,708	4,754	1,401	761	78	1,127	908
DAY	0	0	0	0	0	0	0	0	0	0	0	0	181
DLCO	156	393	0	209	0	223	617	0	0	0	0	0	0
DOM	456	889	1,266	559	674	77	1,341	647	80	136	90	776	567
DPL	0	111	0	382	783	542	1,138	2,691	326	398	0	0	144
DUKE	0	0	0	185	0	0	0	0	0	75	0	0	176
DUQ	0	0	0	0	0	0	0	0	0	0	0	0	0
EKPC	0	0	0	0	0	0	0	0	0	368	0	0	0
EXT	0	0	0	0	0	0	0	0	778	0	0	0	0
JCPLC	0	0	0	0	0	0	79	0	94	0	0	0	0
MEC	0	168	0	0	0	0	222	0	0	1,259	548	730	381
MISO	5,213	2,972	6,166	11,511	14,018	11,196	8,799	8,853	5,531	5,844	5,317	3,314	2,832
NYISO	0	0	0	0	167	128	346	1,442	332	0	0	0	0
OVEC	0	0	0	0	0	0	0	0	0	0	0	0	0
PE	80	96	77	0	0	2,147	1,287	451	1,992	1,338	1,006	2,481	309
PECO	247	0	276	0	390	1,826	718	826	1,268	1,103	341	284	480
PEPCO	149	0	76	143	200	41	0	0	0	0	0	0	0
PPL	176	117	40	146	609	148	224	398	1,370	0	718	778	1,042
PSEG	379	515	1,132	259	1,993	2,268	2,509	170	159	324	174	0	1,244
REC	0	0	0	0	0	0	0	0	0	0	0	0	0

In the PJM Day-Ahead Energy Market, the TPS test is performed in PROBE, as part of the unit commitment process. Table 3-90 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 the TPS test for the transfer interface constraints in the PJM Day-Ahead Energy Market.

153 The constraint data in the month of September 2021 is from the dispatch run from fast start pricing.

Table 3-90 Day-ahead three pivotal supplier test details for interface constraints: January through September, 2021

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
5004/5005	Peak	108	512	29	29	0
	Off Peak	NA	NA	NA	NA	NA
AEP - DOM	Peak	332	542	21	7	14
	Off Peak	NA	NA	NA	NA	NA
AP South	Peak	416	672	27	10	16
	Off Peak	222	342	21	8	12
BC Pepco	Peak	187	1,129	21	18	3
	Off Peak	1,061	1,189	15	0	15

Table 3-91 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 the TPS test for the 10 constraints that were binding for the most hours in the PJM Day-Ahead Energy Market. In the day-ahead energy market, the TPS test evaluates each constraint that was binding for each hour during the operating day.

Table 3-91 Day-ahead three pivotal supplier test details for top 10 congested constraints: January through September, 2021

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Berwick - Koonsville	Peak	3	12	3	0	3
	Off Peak	5	15	3	0	3
Three Mile Island	Peak	336	222	19	2	18
	Off Peak	297	190	17	1	16
Graceton - Safe Harbor	Peak	301	231	21	2	19
	Off Peak	197	203	20	4	16
Ramapo (ConEd) - S Mahwah (RECO)	Peak	21	2	2	0	2
	Off Peak	NA	NA	NA	NA	NA
Cedar Grove Sub - William	Peak	209	156	8	0	8
	Off Peak	167	72	7	0	7
Nottingham	Peak	287	282	22	7	15
	Off Peak	186	215	19	8	11
Bagley - Raphael Road	Peak	322	421	22	6	17
	Off Peak	250	341	22	8	13
East Lima - Haviland	Peak	98	145	10	1	10
	Off Peak	94	129	9	0	9
Monroe - Vineland	Peak	31	72	2	0	2
	Off Peak	10	35	3	0	3
Face Rock	Peak	120	120	9	1	9
	Off Peak	77	90	7	0	7

The local market structure in the real-time energy market associated with each of the frequently binding constraints was analyzed using the three pivotal supplier results in the first nine months of 2021.[154] While the real-time constraint hours include constraints that were binding in the five minute real-time dispatch solution (RT SCED), IT SCED, the software that performs the TPS test, may contain different binding constraints because IT SCED looks ahead to target times that are in the near future to solve for constraints that could be binding, using the load forecast for those times.[155] IT SCED solves for target times that occur at 15 minute time increments, unlike RT SCED that solves for every five minute time increment. The TPS statistics shown in this section present the data from the IT SCED TPS solution. The results of the TPS test are shown for tests that could have resulted in offer capping and tests that resulted in offer capping.

Table 3-92 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 in the PJM Real-Time Energy Market. Table 3-93 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 10 constraints that were binding for the most hours in the PJM Real-Time Energy Market. Table 3-92 and Table 3-93 include analysis of all the tests for every target time where IT SCED determined that constraint relief was needed for each of the constraints shown. The same target time can be evaluated by multiple IT SCED cases at different look ahead times. Each 15 minute target time is solved by 12 different IT SCED cases at different look ahead times. The set of binding constraints for a target time may be different in 12 look ahead IT SCED solutions.

154 See the *MMU Technical Reference for PJM Markets*, p. 38 "Three Pivotal Supplier Test" for a more detailed explanation of the three pivotal supplier test. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

155 Prior to September 1, 2021, the real-time binding constraints were identical in the dispatch (RT SCED) and pricing (LPC) solutions. Beginning September 1, 2021, with implementation of fast start pricing, the set of binding constraints can differ between RT SCED and LPC pricing solutions. The set of constraints reported here are based on the binding constraints in RT SCED. This is because PJM commits and mitigates units based on a dispatch solution in IT SCED without fast start pricing.

Table 3-92 Three pivotal supplier test details for interface constraints: January through September, 2021

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	328	421	19	5	14
	Off Peak	146	548	21	15	6
AP South	Peak	327	717	20	10	10
	Off Peak	388	387	10	5	4
East	Peak	409	468	18	2	16
	Off Peak	NA	NA	NA	NA	NA
PA Central	Peak	15	169	6	2	4
	Off Peak	10	106	4	1	4

Table 3-93 Three pivotal supplier test details for top 10 congested constraints: January through September, 2021

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Brighton	Peak	188	312	19	9	10
	Off Peak	140	250	17	8	9
Bagley - Raphael Road	Peak	86	170	12	6	6
	Off Peak	70	139	11	5	6
Cedar Grove Sub - William	Peak	79	98	6	0	6
	Off Peak	56	93	5	0	5
Lenox - North Meshoppen	Peak	10	25	3	0	3
	Off Peak	7	29	2	0	2
Northwest Tap - Purdue	Peak	33	45	2	0	2
	Off Peak	23	38	2	0	2
Three Mile Island	Peak	80	79	10	1	9
	Off Peak	71	99	10	2	8
Nottingham	Peak	72	105	10	2	8
	Off Peak	52	82	9	1	7
Graceton - Safe Harbor	Peak	75	103	11	3	8
	Off Peak	48	73	9	3	6
Sandburg	Peak	25	12	2	0	2
	Off Peak	23	13	2	0	2
East Lima - Haviland	Peak	27	31	1	0	1
	Off Peak	26	28	1	0	1

The three pivotal supplier test is applied every time the IT SCED 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 offer capping. Steam unit offers that are offer capped in the day-ahead energy market continue to be offer capped in the real-time energy market regardless of their inclusion in the TPS test in real time or the outcome of the TPS test in real time. Steam unit offers that are not offer capped in the day-ahead energy market continue to not be offer capped in the real-time energy market regardless of their inclusion in the TPS test in real time or the outcome of the TPS test in real time.[156] Offline units that are committed to provide relief for a transmission constraint, whose owners fail the TPS test, are committed on the cheaper of their cost or price-based offers. Beginning November 1, 2017, with the introduction of hourly offers and intraday offer updates, certain online units whose commitment is extended beyond the day-ahead or real-time commitment, whose owners fail the TPS test, are also switched to the cost-based offer if it is cheaper than the price-based offer.

Units committed in the day-ahead market often fail the TPS test in the real-time market when they are redispatched to provide relief to transmission constraints, even though they did not fail the TPS test in the day-ahead market. These units are able to set prices with a positive markup in the real-time market. Units that cleared the day-ahead market on their price based schedule were evaluated to identify the units whose offers were mitigated in real-time and the units that cleared on price offers in real-time despite failing the real-time TPS test. Table 3-94 shows that 0.9 percent of unit hours that cleared the day-ahead market on their price based offer were switched to cost in real-time. Table 3-94 shows that 7.2 percent of unit hours that cleared the day-ahead market on their price based offer cleared on their price based offer in real-time despite failing the real-time TPS test.

Table 3-94 Day-ahead units committed on price-based offers that cleared real-time: January through September, 2020 and 2021

	Day Ahead Price Based Unit Hours That Cleared Real-Time			Percent Day Ahead Price Based Unit Hours That Cleared Real-Time	
Year (Jan - Sep)	On Cost	On Price	On Price and Failed TPS Test	On Cost	On Price and Failed TPS Test
2020	8,868	1,973,836	138,726	0.4%	7.0%
2021	18,076	2,049,312	149,323	0.9%	7.2%

The MMU recommends, in order to ensure effective market power mitigation when the TPS test is failed, that offer capping be applied to units that fail the TPS test in the real-time market that were not offer capped at the time of commitment in the day-ahead market or at a prior time in the real-time market.

Table 3-95 and Table 3-96 provide, for the identified constraints, information on total tests applied, the subset of three pivotal supplier tests that could have resulted in offer capping and the portion of those tests that did result in offer capping. Tests where there was at least one offline unit or an online unit eligible for offer capping are considered tests that could have resulted in offer capping. PJM operators also manually commit units for reliability reasons other than providing relief to a binding constraint. Manual commitments are offer capped along with resources that fail the TPS test.

156 If a steam unit were to lower its cost-based offer in real time, it would become eligible for offer capping based on the online TPS test.

Table 3-95 Summary of three pivotal supplier tests applied for interface constraints: January through September, 2021

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	Peak	223	223	100%	1	0%	0%
	Off Peak	30	30	100%	0	0%	0%
AP South	Peak	109	109	100%	1	1%	1%
	Off Peak	58	34	59%	0	0%	0%
Eastern	Peak	48	48	100%	0	0%	0%
	Off Peak	0	0	NA	0	NA	NA
PA Central	Peak	589	471	80%	4	1%	1%
	Off Peak	447	304	68%	3	1%	1%

Table 3-96 Summary of three pivotal supplier tests applied for top 10 congested constraints: January through September, 2021

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
Brighton	Peak	13,985	13,982	100%	568	4%	4%
	Off Peak	12,357	12,353	100%	278	2%	2%
Bagley - Raphael Road	Peak	13,762	13,450	98%	76	1%	1%
	Off Peak	7,954	7,891	99%	38	0%	0%
Cedar Grove Sub - William	Peak	10,235	9,423	92%	84	1%	1%
	Off Peak	6,295	5,365	85%	55	1%	1%
Lenox - North Meshoppen	Peak	11,223	7,299	65%	9	0%	0%
	Off Peak	3,436	1,257	37%	1	0%	0%
Northwest Tap - Purdue	Peak	13,688	2,285	17%	6	0%	0%
	Off Peak	7,212	810	11%	0	0%	0%
Three Mile Island	Peak	14,186	13,068	92%	152	1%	1%
	Off Peak	3,344	3,141	94%	53	2%	2%
Nottingham	Peak	9,285	9,058	98%	62	1%	1%
	Off Peak	5,451	5,259	96%	47	1%	1%
Graceton - Safe Harbor	Peak	5,588	5,540	99%	42	1%	1%
	Off Peak	4,057	4,007	99%	19	0%	0%
Sandburg	Peak	3,488	359	10%	1	0%	0%
	Off Peak	4,405	601	14%	8	0%	1%
East Lima - Haviland	Peak	5,621	34	1%	0	0%	0%
	Off Peak	5,736	18	0%	0	0%	0%

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.

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 with market power have the ability to evade 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-based or price-based offers. In the day-ahead energy market, PJM commits a unit on the schedule that results in the lower overall system production cost. Only under the current approach, where operating parameters are tied to the cost parameters (startup cost, no load cost, and incremental energy offer), is this is consistent with the day-ahead energy market objective of clearing resources to meet the total demand at the lowest bid production cost for the system over the 24 hour period. True least system production cost can be achieved using a approach in which operating parameters and offer parameters are independently evaluated. In the real-time energy market, PJM uses a dispatch cost formula to compare price-based offers and cost-based offers to select the cheaper offer.[157]

157 See OA Schedule 1 § 6.4.1(g).

$$\text{Total Dispatch Cost} = \text{Startup Cost} + \sum_{\text{Min Run}} \text{Hourly Dispatch Cost}$$

where the hourly dispatch cost is calculated for each hour using the offers applicable for that hour as:

$$\text{Hourly Dispatch Cost} = (\text{Incremental Energy Offer@EcoMin} \times \text{EcoMin MW}) + \text{NoLoad Cost}$$

Given the ability to submit offer curves with different markups at different output levels in the price-based offer, unit owners with market power can evade mitigation by using a low markup at low output levels and a high markup at higher output levels. Figure 3-54 shows an example of offers from a unit that has a negative markup at the economic minimum MW level and a positive markup at the economic maximum MW level. The result would be that a unit that failed the TPS test would be committed on its price-based offer that has a lower dispatch cost, even though the price-based offer is higher than cost-based offer at higher output levels and includes positive markups, inconsistent with the explicit goal of local market power mitigation.

Figure 3-54 Offers with varying markups at different MW output levels

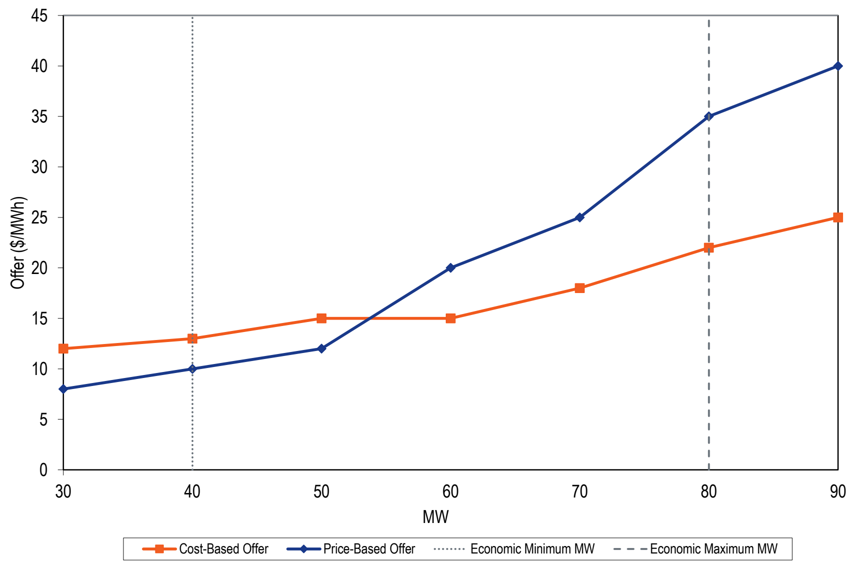


Table 3-97 shows the number and percent of unit schedule hours, by month, when unit offers included crossing curves in the PJM Day-Ahead and Real-Time Energy Markets, in the first nine months of 2021. The analysis only includes units that offer both price-based and cost-based offers. Units in PJM are only required to submit cost-based offers, and they may elect to offer price-based offers, but are not required to do so.

Table 3-97 Units offered with crossing curves in the day-ahead and real-time energy markets: January through September, 2021

	Day-Ahead			Real-Time		
2021	Number of Schedule Hours with Crossing Curves	Total Number of Cost Schedule Hours Offered by Price Based Units	Percent of Schedule Hours with Crossing Curves	Number of Schedule Hours with Crossing Curves	Total Number of Cost Schedule Hours Offered by Price Based Units	Percent of Schedule Hours with Crossing Curves
Jan	61,326	838,152	7.3%	60,557	779,014	7.8%
Feb	56,100	750,072	7.5%	50,867	687,184	7.4%
Mar	70,110	844,732	8.3%	58,436	722,456	8.1%
Apr	73,785	805,512	9.2%	58,649	651,693	9.0%
May	91,452	842,592	10.9%	77,648	715,547	10.9%
Jun	103,578	822,216	12.6%	97,130	768,461	12.6%
Jul	104,730	852,936	12.3%	97,095	808,021	12.0%
Aug	110,185	853,728	12.9%	100,856	805,946	12.5%
Sep	106,904	825,960	12.9%	97,261	738,808	13.2%
Total	778,170	7,435,900	10.5%	698,499	6,677,130	10.5%

Offering a different economic minimum MW level, different minimum run times, or different start up and notification times in the cost-based and price-based offers can also be used to evade mitigation. For example, a unit may offer its price-based offer with a positive markup, but have a shorter minimum run time (MRT) in the price-based offer resulting in a lower dispatch cost for the price-based offer but setting prices at a level that includes a positive markup. Table 3-98 shows the number and percent of unit schedule hours when units offered lower minimum run times in price-based offers than in cost-based offers while having a positive markup in the price based offer.

Table 3-98 Units offered with lower minimum run time on price compared to cost but with positive markup in the day-ahead and real-time energy markets: January through September, 2021[158]

	Day-Ahead			Real-Time		
2021	Number of Schedule Hours with Lower Min Run Time in Price Compared to Cost	Total Number of Cost Schedule Hours Offered by Price Based Units	Percent of Schedule Hours with Lower Min Run Time in Price Compared to Cost	Number of Schedule Hours with Lower Min Run Time in Price Compared to Cost	Total Number of Cost Schedule Hours Offered by Price Based Units	Percent of Schedule Hours with Lower Min Run Time in Price Compared to Cost
Jan	13,151	838,152	1.6%	7,779	779,014	1.0%
Feb	12,162	750,072	1.6%	7,800	687,184	1.1%
Mar	11,513	844,732	1.4%	8,376	722,456	1.2%
Apr	8,220	805,512	1.0%	6,759	651,693	1.0%
May	6,489	842,592	0.8%	5,331	715,547	0.7%
Jun	6,367	822,216	0.8%	5,439	768,461	0.7%
Jul	6,631	852,936	0.8%	5,294	808,021	0.7%
Aug	6,229	853,728	0.7%	5,068	805,946	0.6%
Sep	8,062	825,960	1.0%	7,755	738,808	1.0%
Total	78,824	7,435,900	1.1%	59,601	6,677,130	0.9%

A unit may offer a lower economic minimum MW level on the price-based offer than the cost-based offer. Such a unit may appear to be cheaper to commit on the price-based offer even with a positive markup. A unit with a positive markup can have lower dispatch cost with the price-based offer with a lower economic minimum level compared to cost-based offer. Figure 3-55 shows an example of offers from a unit that has a positive markup and a price-based offer with a lower economic minimum MW than the cost-based offer. Keeping the startup cost, Minimum Run Time and no load cost constant between the price-based offer and cost-based offer, the dispatch cost for this unit is lower on the price-based offer than on the cost-based offer. However, the price-based offer includes a positive markup and could result in setting the market price at a noncompetitive level even after the resource owner fails the TPS test.

158 In the previous version of this report, all the schedule hours with a lower minimum run time in their price-based offer compared to the cost-based offer in the first three months of 2021 were incorrectly included, regardless of the markup in the price-based offer. This table is corrected to include only those schedule hours with lower minimum run time in their price-based offer compared to the cost-based offer while offering a positive markup in the price-based offer.

Figure 3-55 Offers with a positive markup but different economic minimum MW

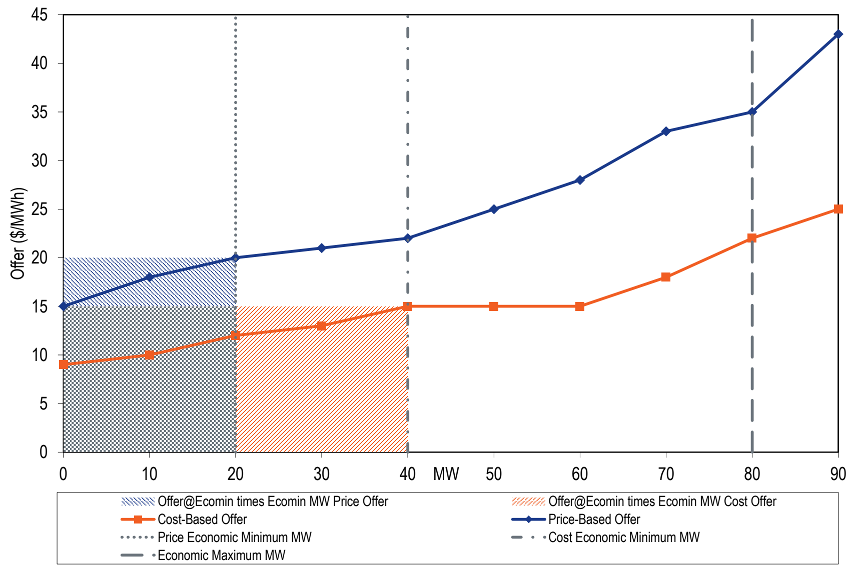


Table 3-99 shows the number and percent of unit schedule hours when units offered lower economic minimum MW in price-based offers than in cost-based offers while having a positive markup in the price-based offer.

Table 3-99 Units offered with lower economic minimum MW on price compared to cost but with positive markup in the day-ahead and real-time energy markets: January through September, 2021[159]

	Day-Ahead			Real-Time		
2021	Number of Schedule Hours with Lower Economic Minimum MW in Price Compared to Cost	Total Number of Cost Schedule Hours Offered by Price Based Units	Percent of Schedule Hours with Lower Economic Minimum MW in Price Compared to Cost	Number of Schedule Hours with Lower Economic Minimum MW in Price Compared to Cost	Total Number of Cost Schedule Hours Offered by Price Based Units	Percent of Schedule Hours with Lower Economic Minimum MW in Price Compared to Cost
Jan	0	838,152	0.0%	0	779,014	0.0%
Feb	216	750,072	0.0%	194	687,184	0.0%
Mar	1,486	844,732	0.2%	1,174	722,456	0.2%
Apr	1,440	805,512	0.2%	1,440	651,693	0.2%
May	1,488	842,592	0.2%	456	715,547	0.1%
Jun	1,440	822,216	0.2%	1,128	768,461	0.1%
Jul	744	852,936	0.1%	512	808,021	0.1%
Aug	864	853,728	0.1%	588	805,946	0.1%
Sep	1,152	825,960	0.1%	72	738,808	0.0%
Total	8,830	7,435,900	0.1%	5,564	6,677,130	0.1%

159 In the previous version of this report, all the schedule hours with a lower economic minimum MW in their price-based offer compared to the cost-based offer in the first three months of 2021 were incorrectly included, regardless of the markup in the price-based offer. This table is corrected to include only those schedule hours with lower economic minimum MW in their price-based offer compared to the cost-based offer while offering a positive markup in the price-based offer.

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 3-56 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. Table 3-100 shows the number and percent of dual fuel unit hours where the price-based offer does not have a comparable cost-based offer with a matching fuel, and contains a negative markup. The analysis includes only those units that offered multiple offers (cost or price) with different fuels in the first nine months of 2021.

Figure 3-56 Dual fuel unit offers

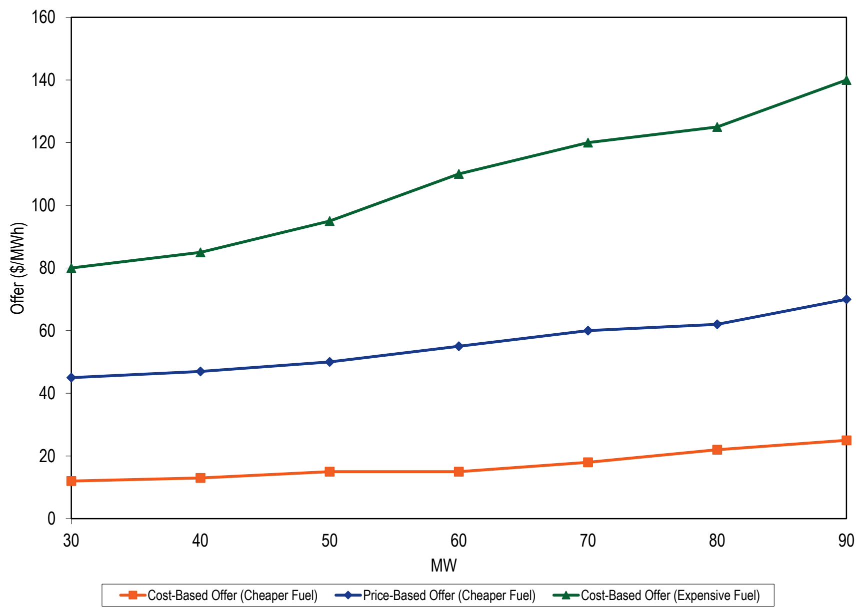


Table 3-100 Dual fuel unit offers with negative markup but different fuel: January through September, 2021

	Day-Ahead			Real-Time		
2021	Number of Unit Hours With Negative Markup And No Matching Fuel on Cost	Total Number of Unit Hours By Units With Multiple Fuels	Percent Unit Hours With Negative Markup And No Matching Fuel on Cost	Number of Unit Hours With Negative Markup And No Matching Fuel on Cost	Total Number of Unit Hours By Units With Multiple Fuels	Percent Unit Hours With Negative Markup And No Matching Fuel on Cost
Jan	2,633	198,432	1.3%	2,633	178,118	1.5%
Feb	5,360	170,184	3.1%	5,360	145,413	3.7%
Mar	3,096	195,816	1.6%	3,096	150,583	2.1%
Apr	4,173	176,976	2.4%	4,173	152,556	2.7%
May	1,560	181,872	0.9%	1,560	159,862	1.0%
Jun	1,478	182,952	0.8%	1,478	177,296	0.8%
Jul	10,488	197,808	5.3%	10,488	190,135	5.5%
Aug	9,451	198,768	4.8%	9,451	188,851	5.0%
Sep	9,294	188,400	4.9%	9,294	171,114	5.4%
Total	47,533	1,691,208	2.8%	47,533	1,513,928	3.1%

These issues can be solved by simple rule changes.[160] The MMU recommends, in order to ensure effective market power mitigation when the TPS test is failed, that markup be consistently positive or negative across the full MWh range of price and cost-based offers. This means that the cost-based and price-based offer curves never cross.[161].

Levels of offer capping have historically been low in PJM, as shown in Table 3-102. But offer capping remains a critical element of PJM market rules because it is designed to prevent the exercise of local market power. While overall offer capping levels have been low, there are a significant number of units with persistent structural local market power that would have a significant impact on prices in the absence of local market power mitigation. Until November 1, 2017, only uncommitted resources, started to relieve a transmission constraint, were subject to offer capping. Beginning November 1, 2017, under certain circumstances, online resources that are committed beyond their original commitment (day-ahead or real-time) can be offer capped if the owner fails the TPS test, and the latest available cost-based offer is determined to be lower than the price-based offer.[162] Units running in real time as part of their original commitment on the price-based offer on economics, and that can provide incremental relief to a constraint, cannot be switched to their cost-based offer.

The offer capping percentages shown in Table 3-101 include units that are committed to provide constraint relief whose owners failed the TPS test in the energy market excluding units that were committed for reliability reasons, providing black start and providing reactive support. Offer capped unit run hours and offer capped generation (in MWh) are shown as a percentage of the total run hours and the total generation (MWh) from all the units in the PJM energy market.[163] Beginning November 1, 2017, with the introduction of hourly offers, certain online units, whose owners fail the TPS test in the real-time energy market for providing constraint relief, can be offer capped and dispatched on their cost-based offer subsequent to a real-time hourly offer update. This is reflected in the slightly higher rate of offer capping in the real-time energy market since 2017.

Table 3-101 Offer capping statistics – energy only: January through September, 2017 to 2021

	Real-Time		Day-Ahead	
(Jan-Sep)	Unit Hours Capped	MWh Capped	Unit Hours Capped	MWh Capped
2017	0.3%	0.1%	0.0%	0.1%
2018	1.0%	0.5%	0.1%	0.1%
2019	1.6%	1.1%	1.2%	0.8%
2020	1.0%	1.2%	1.6%	1.3%
2021	1.3%	1.0%	1.4%	0.8%

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

161 See related recommendations about mitigation of operating parameters and financial offer parameters.

162 See OA Schedule 1 § 6.4.1.

163 Prior to the *2018 Quarterly State of the Market Report for PJM: January through June*, these tables presented the offer cap percentages based on total bid unit hours and total load MWh. Beginning with the quarterly report for January through June, 2018, the statistics have been updated with percentages based on run hours and total generation MWh from units modeled in the energy market.

Table 3-102 shows the offer capping percentages including units committed to provide constraint relief and units committed for reliability reasons. Reliability reasons include reactive support or local voltage support. PJM creates closed loop interfaces to, in some cases, model reactive constraints. The result was higher LMPs in the closed loop interfaces, which increased economic dispatch, which contributed to the reduction in units offer capped for reactive support over time in Table 3-103. In instances where units are committed and offer capped for the modeled closed loop interface constraints, they are considered offer capped for providing constraint relief, and not for reliability. They are included in the offer capping percentages in Table 3-101. Prior to closed loop interfaces, these units were considered as committed for reactive support, and were included in the offer capping statistics for reliability in Table 3-103.

Table 3-102 Offer capping statistics for energy and reliability: January through September, 2017 to 2021

	Real-Time		Day-Ahead	
(Jan-Sep)	Unit Hours Capped	MWh Capped	Unit Hours Capped	MWh Capped
2017	0.4%	0.4%	0.1%	0.3%
2018	1.2%	0.8%	0.2%	0.4%
2019	1.6%	1.1%	1.2%	0.8%
2020	1.0%	1.2%	1.6%	1.4%
2021	1.3%	1.0%	1.4%	0.8%

Table 3-103 shows the offer capping percentages for units committed for reliability reasons, including units committed for reactive support. The low offer cap percentages do not mean that units manually committed for reliability reasons do not have market power. All units manually committed for reliability have market power and all are treated as if they had market power. These units are not capped to their cost-based offers because they tend to offer with a negative markup in their price-based offers, particularly at the economic minimum level, which means that PJM's offer capping process results in the use of the price-based offer for commitment. However, the price-based offers have inflexible parameters such as longer minimum run times that may lead to higher total commitment cost if the unit was only needed for a shorter period that is less than its inflexible minimum run time.

Table 3-103 Offer capping statistics for reliability: January through September, 2017 to 2021

	Real-Time		Day-Ahead	
(Jan-Sep)	Unit Hours Capped	MWh Capped	Unit Hours Capped	MWh Capped
2017	0.10%	0.30%	0.10%	0.20%
2018	0.14%	0.29%	0.12%	0.23%
2019	0.01%	0.02%	0.01%	0.01%
2020	0.00%	0.01%	0.00%	0.00%
2021	0.02%	0.04%	0.02%	0.02%

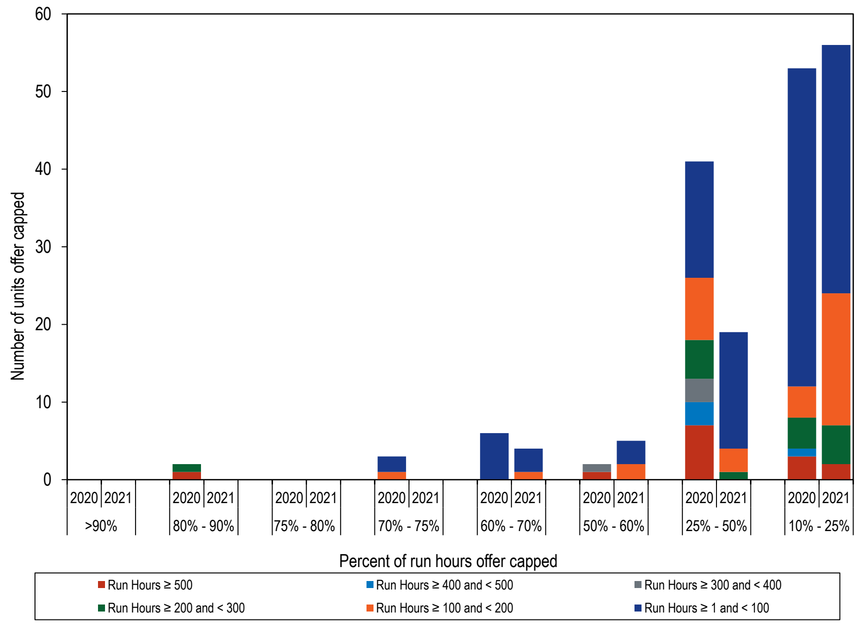
Table 3-104 presents data on the frequency with which units were offer capped in the first nine months of 2020 and 2021 as a result of failing the TPS test to provide energy for constraint relief in the real-time energy market and for reliability reasons. Table 3-104 shows that no units were offer capped for 80 percent or more of their run hours in the first nine months of 2021 compared to two units in the first nine months of 2020.

Table 3-104 Real-time offer capped unit statistics: January through September, 2020 and 2021

		Offer-Capped Hours					
Run Hours Offer-Capped, Percent Greater Than Or Equal To:	Jan - Sep	Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
90%	2020	0	0	0	0	0	0
	2021	0	0	0	0	0	0
80% and < 90%	2020	1	0	0	1	0	0
	2021	0	0	0	0	0	0
75% and < 80%	2020	0	0	0	0	0	0
	2021	0	0	0	0	0	0
70% and < 75%	2020	0	0	0	0	1	2
	2021	0	0	0	0	0	0
60% and < 70%	2020	0	0	0	0	0	6
	2021	0	0	0	0	1	3
50% and < 60%	2020	1	0	1	0	0	0
	2021	0	0	0	0	2	3
25% and < 50%	2020	7	3	3	5	8	15
	2021	0	0	0	1	3	15
10% and < 25%	2020	3	1	0	4	4	41
	2021	2	0	0	5	17	32

Figure 3-57 shows the frequency with which units were offer capped in the first nine months of 2020 and 2021 for failing the TPS test to provide energy for constraint relief in the real–time energy market and for reliability reasons.

Figure 3-57 Real-time offer capped unit statistics: January through September, 2020 and 2021



Markup Index

Markup is a summary measure of participant offer behavior or conduct for individual units. When a seller responds competitively to a market price, markup is zero. When a seller exercises market power in its pricing, markup is positive. The degree of markup increases with the degree of market power. The markup index for each marginal unit is calculated as (Price – Cost)/Price.[164] The markup index is normalized and can vary from -1.00 when the offer price is less than the cost-based offer price, to 1.00 when the offer price is higher than the cost-based offer price. The markup index does not measure the impact of unit markup on total LMP. The dollar markup for a unit is the difference between price and cost.

Real-Time Markup Index

Table 3-105 shows the average markup index of marginal units in the real-time energy market, by offer price category using unadjusted cost-based offers. Table 3-106 shows the average markup index of marginal units in the real-time energy market, by offer price category using adjusted cost-based offers. The unadjusted markup is the difference between the price-based offer and the cost-based offer including the 10 percent adder in the cost-based offer. The adjusted markup is the difference between the price-based offer and the cost-based offer excluding the 10 percent adder from the cost-based offer. The adjusted markup is calculated for coal, gas and oil units because these units have consistently had price-based offers less than cost-based offers.[165] The markup is negative if the cost-based offer of the marginal unit exceeds its price-based offer at its operating point.

All generating units are allowed to add an additional 10 percent to their cost-based offer. The 10 percent adder was included 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. The owners of coal units, facing competition, typically exclude the additional 10 percent from their actual offers. The owners of many gas fired and oil fired units have also begun to exclude the 10 percent adder. The introduction of hourly offers and intraday offer updates in November 2017 allows gas and oil generators to directly incorporate the impact of ambient temperature changes in fuel consumption in offers.

PJM implemented Fast Start Pricing on September 1, 2021. For all the fast start marginal units starting from September 1, 2021, the markup includes markup in the incremental offer, markup in the amortized start up offer, and markup in the amortized no load offer.

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

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

Even the adjusted markup overestimates the negative markup because units facing increased competitive pressure have excluded both the 10 percent and components of operating and maintenance costs that are not short run marginal costs. The PJM Market rules permit the 10 percent adder and maintenance costs, which are not short run marginal costs, under the definition of cost-based offers. Actual market behavior reflects the fact that neither is part of a competitive offer and neither is a short run marginal cost.[166]

In the first nine months of 2021, the average markup index in the real-time market was less than 0.01. The average dollar markups of units with offer prices less than $10 was negative (-$8.27 per MWh) when using unadjusted cost-based offers. The average dollar markups of units with offer prices between $10 and $15 was negative (-$1.27 per MWh) when using unadjusted cost-based offers. Negative markup means the unit is offering to run at a price less than its cost-based offer, revealing a short run marginal cost that is less than the maximum allowable cost-based offer under the PJM Market Rules.

Some marginal units did have substantial markups. Among the units that were marginal in the first nine months of 2021, 1.3 percent had offer prices above $400 per MWh. Among the units that were marginal in the first nine months of 2020, none had offer prices greater than $400 per MWh. Using the unadjusted cost-based offers, the highest markup for any marginal unit in the first nine months of 2021 was more than $400, and the highest markup in the first nine months of 2020 was more than $200.

166 See PJM. "Manual 15: Cost Development Guidelines," Rev. 38 (June 6, 2021).

Table 3-105 Average, real-time marginal unit markup index (By offer price category unadjusted): January through September, 2020 and 2021

	2020 (Jan - Sep)			2021 (Jan - Sep)		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $10	(0.05)	($1.16)	13.8%	0.20	($8.27)	6.3%
$10 to $15	0.03	$0.22	40.2%	(0.07)	($1.27)	4.4%
$15 to $20	0.00	($0.34)	29.9%	(0.04)	($0.94)	18.9%
$20 to $25	0.03	($0.05)	10.6%	(0.03)	($0.89)	20.8%
$25 to $50	0.12	$3.26	3.9%	0.00	($0.28)	41.5%
$50 to $75	0.53	$31.06	0.4%	0.14	$7.81	5.3%
$75 to $100	0.52	$44.59	0.2%	0.27	$22.81	0.9%
$100 to $125	0.09	$10.25	0.6%	0.29	$30.70	0.4%
$125 to $150	0.02	$2.58	0.4%	0.34	$46.14	0.2%
$150 to $400	0.36	$59.98	0.2%	0.11	$23.44	1.3%
All Offers	0.02	$0.33	100.0%	0.00	$0.29	100.0%

Table 3-106 Average, real-time marginal unit markup index (By offer price category adjusted): January through September, 2020 and 2021

	2020 (Jan - Sep)			2021 (Jan - Sep)		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $10	0.01	($0.58)	13.8%	0.14	($5.19)	6.2%
$10 to $15	0.11	$1.37	40.2%	0.00	($0.13)	5.0%
$15 to $20	0.09	$1.26	29.9%	0.03	$0.46	21.4%
$20 to $25	0.11	$1.93	10.6%	0.05	$0.98	23.2%
$25 to $50	0.19	$5.72	3.9%	0.08	$2.30	37.1%
$50 to $75	0.57	$33.51	0.4%	0.21	$11.72	4.3%
$75 to $100	0.56	$48.50	0.2%	0.32	$26.51	0.8%
$100 to $125	0.18	$19.63	0.6%	0.31	$33.05	0.4%
$125 to $150	0.12	$14.50	0.4%	0.38	$51.06	0.2%
$150 to $400	0.42	$69.67	0.2%	0.19	$38.37	1.4%
All Offers	0.10	$1.80	100.0%	0.07	$2.36	100.0%

Table 3-107 shows the percentage of marginal units that had markups, calculated using unadjusted cost-based offers, below, above and equal to zero for coal, gas and oil fuel types.[167] Table 3-108 shows the percentage of marginal units that had markups, calculated using adjusted cost-based offers, below, above and equal to zero for coal, gas and oil fuel types. In the first nine months of 2021, using unadjusted cost-based offers for coal units, 50.49 percent of marginal coal units had negative markups. In the first nine months

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

of 2021, using adjusted cost-based offers for coal units, 30.84 percent of marginal coal units had negative markups. The share of marginal gas units with negative markups at the dispatch point on their offer curve increased from 36.86 percent in the first nine months of 2020 to 47.64 percent in the first nine months of 2021 when using unadjusted cost based offers. Most marginal combined cycle units had significant negative markups, particularly during the periods of high natural gas prices in February 2021. Cost-based offers for gas fired units are frequently based on the current spot price of fuel while price-based offers may reflect a range of factors including sellers' fuel purchase prices and power sales prices.

Table 3-107 Percent of marginal units with markup below, above and equal to zero (By fuel type with unadjusted offers): January through September, 2020 and 2021

	2020 (Jan - Sep)			2021 (Jan - Sep)		
Type/Fuel	Negative	Zero	Positive	Negative	Zero	Positive
Coal	56.48%	22.10%	21.42%	50.49%	24.21%	25.30%
Gas	36.86%	6.51%	56.63%	47.64%	17.35%	35.01%
Oil	3.11%	96.53%	0.36%	4.93%	93.53%	1.54%

Table 3-108 Percent of marginal units with markup below, above and equal to zero (By fuel type with adjusted offers): January through September, 2020 and 2021

	2020 (Jan - Sep)			2021 (Jan - Sep)		
Type/Fuel	Negative	Zero	Positive	Negative	Zero	Positive
Coal	34.56%	17.71%	47.73%	30.84%	13.95%	55.21%
Gas	22.55%	4.93%	72.52%	29.15%	8.35%	62.50%
Oil	2.89%	66.06%	31.05%	1.05%	92.58%	6.37%

Figure 3-58 shows the frequency distribution of hourly markups for all gas units offered in the first nine months of 2020 and the first nine months of 2021 using unadjusted cost-based offers. The highest markup within the economic operating range of the unit's offer curve was used in the frequency distributions.[168] Of the gas units offered in the PJM market in the first nine months of 2021, 19.1 percent of gas unit hours had a maximum markup that was negative and 11.9 percent of gas fired unit hours had a maximum markup above $100 per MWh. The share of offered gas units with maximum markup that was negative decreased in the first nine months of 2021 compared to the first nine months of 2020 while the share of marginal gas units with negative markups increased.

Figure 3-58 Frequency distribution of highest markup of gas units offered using unadjusted cost offers: January through September, 2020 and 2021

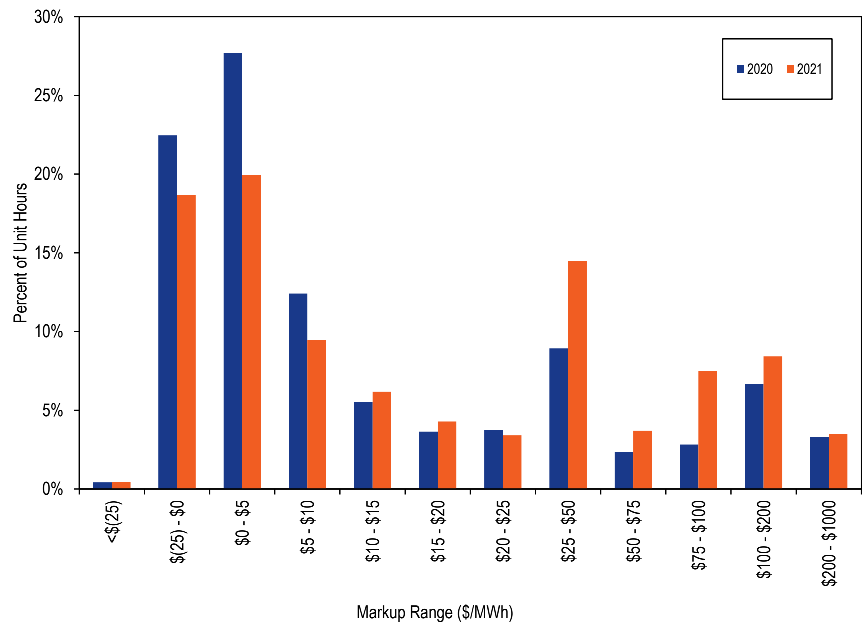


Figure 3-59 shows the frequency distribution of hourly markups for all coal units offered in the first nine months of 2020 and the first nine months of 2021 using unadjusted cost-based offers. Of the coal units offered in the PJM market in the first nine months of 2021, 35.2 percent of coal unit hours had a maximum markup that was negative or equal to zero, decreasing from 48.4 in the first nine months of 2020. The share of offered coal units with maximum markup that was negative and the share of marginal coal units with negative markups decreased in the first nine months of 2021 compared to the first nine months of 2020.

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

Figure 3-59 Frequency distribution of highest markup of coal units offered using unadjusted cost offers: January through September, 2020 and 2021

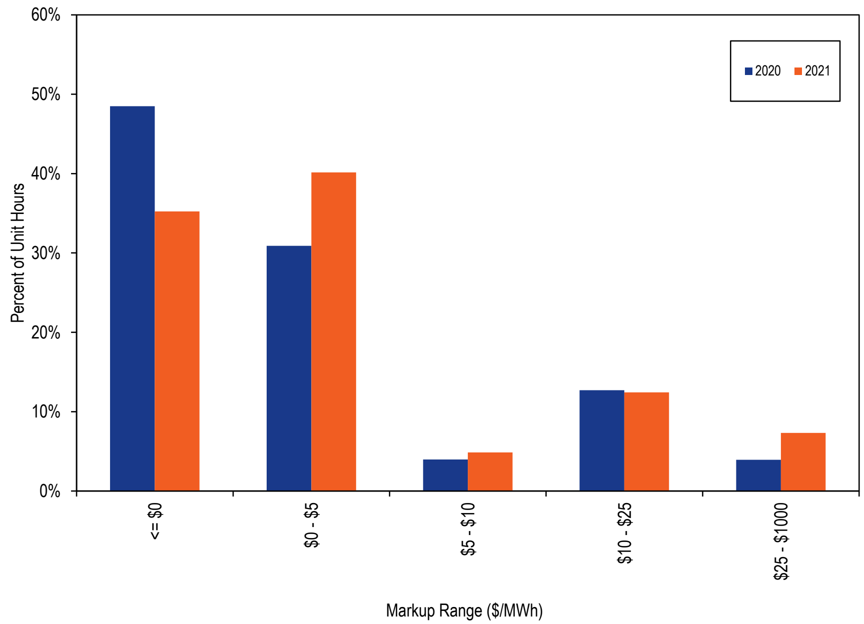


Figure 3-60 Frequency distribution of highest markup of oil units offered using unadjusted cost offers: January through September, 2020 and 2021

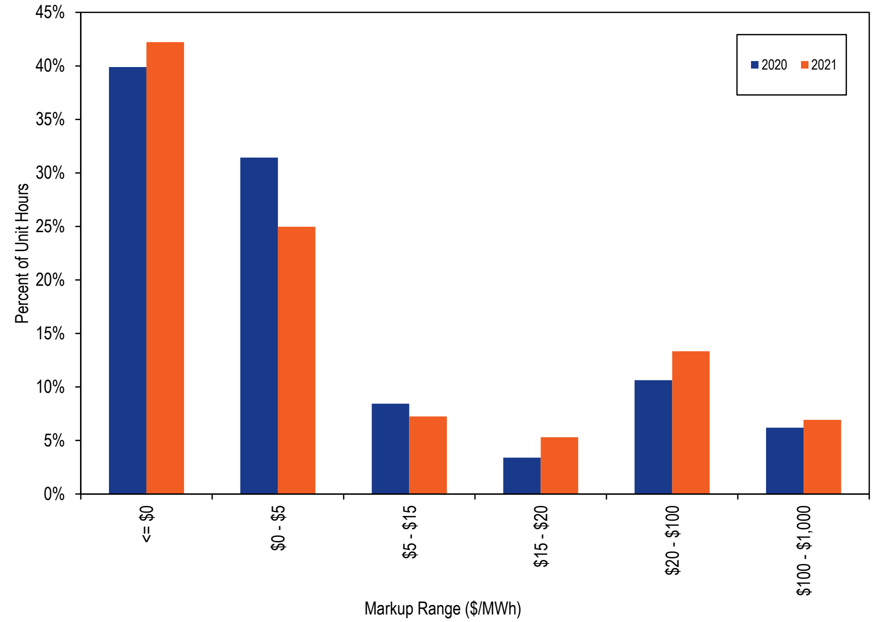


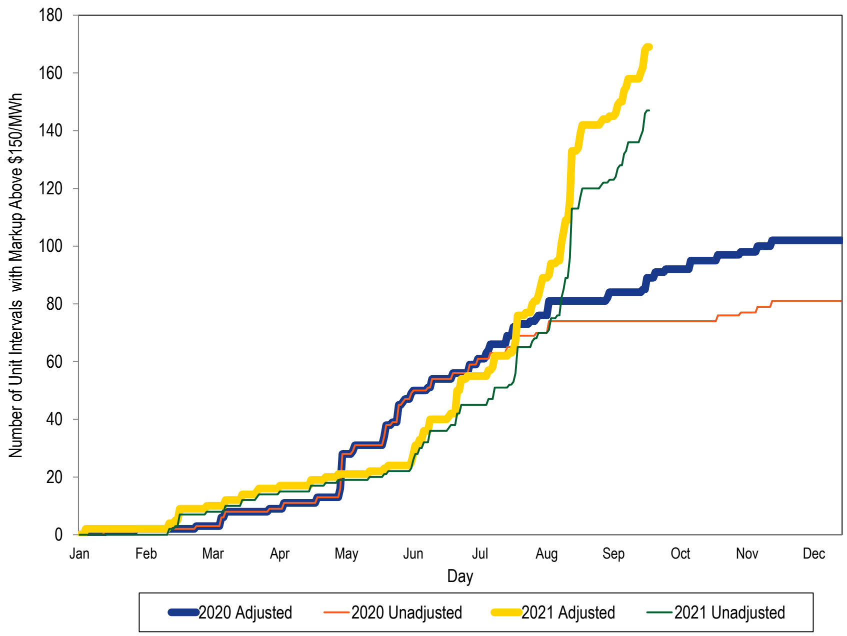
Figure 3-60 shows the frequency distribution of hourly markups for all offered oil units in the first nine months of 2020 and the first nine months of 2021 using unadjusted cost-based offers. Of the oil units offered in the PJM market in the first nine months of 2021, 42.2 percent of oil unit hours had a maximum markup that was negative or equal to zero. More than 6.0 percent of oil fired unit hours had a maximum markup above $100 per MWh.

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

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

Figure 3-61 shows the number of marginal unit intervals in the first nine months of 2021 and 2020 with markup above $150 per MWh. For several of the marginal unit intervals with markups above $150 per MWh, the units failed the TPS test for the hour. These exercises of market power are a result of PJM's failure to address the issues with the offer capping process identified by the MMU. If PJM adopted the MMU's recommendations, these exercises of market power would not occur.

Figure 3-61 Cumulative number of unit intervals with markups above $150 per MWh: January through September, 2020 and 2021



Day-Ahead Markup Index

Table 3-109 shows the average markup index of marginal generating units in the day-ahead energy market, by offer price category using unadjusted cost-based offers. The majority of marginal units are virtual transactions, which do not have markup. The average dollar markups of units with offer prices less than $10 was negative (-$1.07 per MWh) when using unadjusted cost-based offers. The average dollar markups of units with offer prices between $10 and $15 was negative (-$0.53 per MWh) when using unadjusted cost-based offers.

Some marginal units did have substantial markups. Among the units that were marginal in the day-ahead market in January through September, 2021, none had offer prices above $400 per MWh. Using the unadjusted cost-based offers, the highest markup for any marginal unit in the day-ahead market in the first nine months of 2021 was more than $140 per MWh while the highest markup in the first nine months of 2020 was less than $80 per MWh.

Table 3-109 Average day-ahead marginal unit markup index (By offer price category, unadjusted): January through September, 2020 and 2021

	2020 (Jan - Sep)			2021 (Jan - Sep)		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $10	(0.00)	($0.62)	1.5%	0.17	($1.07)	0.9%
$10 to $15	0.08	$0.76	5.4%	(0.01)	($0.53)	0.5%
$15 to $20	0.11	$1.38	6.1%	0.07	$0.91	3.7%
$20 to $25	0.03	($0.08)	2.1%	0.00	($0.24)	5.1%
$25 to $50	0.10	$2.99	0.8%	0.04	$0.63	8.3%
$50 to $75	0.18	$10.58	0.0%	0.14	($1.32)	1.0%
$75 to $100	0.48	$42.31	0.0%	0.28	$24.65	0.1%
$100 to $125	0.00	($0.01)	0.0%	0.24	$24.10	0.1%
$125 to $150	0.00	$0.00	0.0%	0.12	$15.86	0.0%
>= $150	0.01	$1.49	0.0%	0.05	$8.44	0.1%
All Offers	0.08	$0.92	16.1%	0.04	$0.57	19.7%

Table 3-110 shows the average markup index of marginal generating units in the day-ahead energy market, by offer price category using adjusted cost-based offers. In the first nine months of 2021, 3.7 percent of marginal resources had offers between $15 and $20 per MWh, and the average dollar markup and the average markup index were both positive. The average markup index increased from 0.06 in the first nine months of 2020, to 0.21 in the first nine months of 2021 in the offer price category less than $10.

Table 3-110 Average day-ahead marginal unit markup index (By offer price category, adjusted): January through September, 2020 and 2021

	2020 (Jan - Sep)			2021 (Jan - Sep)		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $10	0.06	($0.08)	1.5%	0.21	($0.84)	0.9%
$10 to $15	0.15	$1.86	5.4%	0.06	$0.61	0.5%
$15 to $20	0.18	$2.81	6.1%	0.15	$2.44	3.7%
$20 to $25	0.11	$1.91	2.1%	0.09	$1.80	5.1%
$25 to $50	0.18	$5.50	0.8%	0.12	$3.55	8.3%
$50 to $75	0.26	$14.91	0.0%	0.21	$3.90	1.0%
$75 to $100	0.51	$44.70	0.0%	0.34	$29.55	0.1%
$100 to $125	0.02	$2.34	0.0%	0.31	$32.15	0.1%
$125 to $150	0.02	$3.17	0.0%	0.16	$21.40	0.0%
>= $150	0.09	$15.37	0.0%	0.09	$16.31	0.1%
All Offers	0.15	$2.32	16.1%	0.12	$3.00	19.7%

No Load and Start Cost Markup

Generator energy offers in PJM are comprised of three parts, an incremental energy offer curve, no load cost and start cost. In cost-based offers, all three parts are capped at the level allowed by Schedule 2 of the Operating Agreement, the Cost Development Guidelines (Manual 15) and fuel cost policies approved by PJM. In price-based offers, the incremental energy offer curve is capped at $1,000 per MWh (unless the verified cost-based offer exceeds $1,000 per MWh, but cannot exceed $2,000 per MWh). Generators are allowed to choose whether to use price-based or cost-based no load cost and start costs twice a year. If price-based is selected, the no load and start costs do not have a cap, but the offers cannot be changed for six months (April through September and October through March). If cost-based is selected, the cap is the same as the cap of the no load and start costs in the cost-based offers, and the offers can be updated daily or hourly. Table 3-111 shows the caps on the three parts of cost-based and price-based offers.

Table 3-111 Cost-based and price-based offer caps

Offer Type	No Load and Start Cost Option	Incremental Offer Curve Cap	No Load Cost Cap	Start Cost Cap
Cost-Based	Cost-Based	Based on OA Schedule 2, Cost Development Guidelines (Manual 15) and Fuel Cost Policies		
Price-Based	Cost-Based	$1,000/MWh or based on OA Schedule 2, Cost Development Guidelines (Manual 15) and Fuel Cost Policies if verified cost-based offer exceeds $1,000/MWh but no more than $2,000/MWh.	Based on OA Schedule 2, Cost Development Guidelines (Manual 15) and Fuel Cost Policies	Based on OA Schedule 2, Cost Development Guidelines (Manual 15) and Fuel Cost Policies
	Price-Based		No cap but can only be changed twice a year.	No cap but can only be changed twice a year.

Table 3-112 shows the number of units that chose the cost-based option and the price-based option. In the first nine months of 2021, 92 percent of all generators that submitted no load or start costs chose to have cost-based no load and start costs in their price-based offers, one percentage point higher than in the first nine months of 2020.

Table 3-112 Number of units selecting cost-based and price-based no load and start costs: January through September, 2020 and 2021

	2020		2021	
No Load and Start Cost Option	Number of units	Percent	Number of units	Percent
Cost-Based	547	91%	535	92%
Price-Based	55	9%	46	8%
Total	602	100%	581	100%

Generators can have positive or negative markups in their no load and start costs under the price-based option. Generators cannot have positive markups in no load and start costs when they select the cost-based option. Table 3-113 shows the average markup in the no load and start costs in the first nine months of 2020 and 2021. Generators that selected the cost-based start and no load option offered on average with a negative markup on the no load cost and a negative markup on the start costs. The price-based offers were actually lower than the cost-based offers. Generators that selected the price-based start and no load option offered on average with a negative markup on the no load cost but with very large positive markups on the start costs.

Table 3-113 No load and start cost markup: January through September, 2020 and 2021

Period	No Load and Start Cost Option	No Load Cost	Cold Start Cost	Intermediate Start Cost	Hot Start Cost
2020	Cost-Based	(9%)	(7%)	(6%)	(6%)
	Price-Based	(2%)	570%	711%	750%
2021	Cost-Based	(8%)	(8%)	(9%)	(9%)
	Price-Based	(55%)	324%	377%	479%

Energy Market Cost-Based Offers

The application of market power mitigation rules in the day-ahead energy market and the real-time energy market helps ensure competitive market outcomes even in the presence of structural market power.

Cost-based offers in PJM affect all aspects of the PJM energy market. Cost-based offers affect prices when units are committed and dispatched on their cost-based offers. In the first nine months of 2021, 7.1 percent of the marginal units set prices based on cost-based offers, 0.5 percentage points higher than in the first nine months of 2020.

The efficacy of market power mitigation rules depends on the definition of a competitive offer. A competitive offer is equal to short run marginal costs. The enforcement of market power mitigation rules is undermined if the definition of a competitive offer is not correct. The significance of competition metrics like markup is also undermined if the definition of a competitive offer is not correct. The definition of a competitive offer in the PJM market rules is not correct. Some unit owners include costs that are not short run marginal costs in offers, including maintenance costs. This issue can be resolved by simple changes to the PJM market rules to incorporate a clear and accurate definition of short run marginal costs.

The efficacy of market power mitigation rules also depends on the accuracy of cost-based offers. Some unit owners use fuel cost policies that are not algorithmic, verifiable, and systematic. These inadequate fuel cost policies permit overstated fuel costs in cost-based offers. FERC's decision to permit maintenance costs in cost-based offers that are not short run marginal costs also results in overstated cost-based offers.

When market power mitigation is not effective due to inaccurate cost-based offers that exceed short run marginal costs, market power causes increases in market prices above the competitive level.

Short Run Marginal Costs

Short run marginal costs are the only costs relevant to competitive offers in the energy market. Specifically, the competitive energy offer level is the short run marginal cost of production. The current PJM market rules distinguish costs includable in cost-based energy offers from costs includable in cost-based capacity market offers based on whether costs are directly related to energy production. The rules do not provide a clear standard. Energy production is the sole purpose of a power plant. Therefore, all costs, including the sunk costs, are directly related to energy production. This current ambiguous criterion is incorrect and, in addition, allows for multiple interpretations, which could lead to tariff violations. The incorrect rules will lead to higher energy market prices and higher uplift.

There are three types of costs identified under PJM rules as of April 15, 2019: variable costs, avoidable costs, and fixed costs. The criterion for whether a generator may include a cost in an energy market cost-based offer, a variable cost, is that the cost is "directly related to electric production."[169]

Variable costs are comprised of short run marginal costs and avoidable costs that are directly related to electric production. Short run marginal costs are the cost of inputs consumed or converted to produce energy, and the costs associated with byproducts that result from consuming or converting materials to produce energy, net of any revenues from the sale of those byproducts. The categories of short run marginal costs are fuel costs, emission allowance costs, operating costs, and energy market opportunity costs.[170]

169 See 167 FERC ¶ 61,030 (2019).
170 See OA Schedule 2(a).

Avoidable costs are annual costs that would be avoided if energy were not produced over an annual period. The PJM rules divide avoidable costs into those that are directly related to electric production and those not directly related to electric production. The distinction is ambiguous at best. PJM includes overhaul and maintenance costs, replacement of obsolete equipment, and overtime staffing costs in costs related to electric production. PJM includes taxes, preventative maintenance to auxiliary equipment, improvement of working equipment, maintenance expenses triggered by a time milestone (e.g. annual, weekly) and pipeline reservation charges in costs not related to electric production.

Fixed costs are costs associated with an investment in a facility including the return on and of capital.

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

Fuel Cost Policies

Fuel cost policies (FCP) document the process by which market sellers calculate the fuel cost component of their cost-based offers. Short run marginal fuel costs include commodity costs, transportation costs, fees, and taxes for the purchase of fuel.

Fuel Cost Policy Review

Table 3-114 shows the status of all fuel cost policies (FCP) as of September 30, 2021. As of September 30, 2021, 718 units (85 percent) had an FCP passed by the MMU, 22 units had an FCP under MMU review (submitted) and 109 units (13 percent) had an FCP failed by the MMU. The units with fuel cost policies failed by the MMU represented 22,654 MW. All units' FCPs were approved by PJM. The number of units with fuel cost policies passed by the MMU decreased by 55 on June 30, 2021 compared to December 31, 2020, mostly from units that offer zero that are no longer required to have Fuel Cost Policies and policies under review. As of September 30, 2021, 466 units did not have FCPs approved by PJM. Units without approved FCPs cannot submit nonzero cost based offers.

Table 3-114 FCP Status for PJM generating units: September 30, 2021

	MMU Status			
PJM Status	Pass	Submitted	Fail	Total
Submitted	0	0	0	0
Under Review	0	0	0	0
Customer Input Required	0	0	0	0
Approved	718	22	109	849
Total	718	22	109	849

The MMU performed a detailed review of every FCP. PJM approved the FCPs that the MMU passed. PJM approved every FCP failed by the MMU.

The standards for the MMU's market power evaluation are that FCPs be algorithmic, verifiable and systematic, accurately reflecting the short run marginal cost of producing energy. In its filings with FERC, PJM agreed with the MMU that FCPs should be verifiable and systematic.[171] Verifiable means that the FCP requires a market seller to provide a fuel price that can be calculated by the MMU after the fact with the same data available to the market seller at the time the decision was made, and documentation for that data from a public or a private source. Systematic means that the FCP must document a clearly defined quantitative method or methods for calculating fuel costs, including objective triggers for each method.[172] PJM and FERC did not agree that fuel cost policies should be algorithmic, although PJM's standard effectively requires algorithmic fuel cost policies by describing the requirements.[173] Algorithmic means that the FCP must use a set of defined, logical steps, analogous to a recipe, to calculate the fuel costs. These steps may be as simple as a single number from a contract, a simple average of broker quotes, a simple average of bilateral offers, or the weighted average index price posted on the Intercontinental Exchange trading platform ('ICE').[174]

FCPs are not verifiable and systematic if they are not algorithmic. The natural gas FCPs failed by the MMU and approved by PJM are not verifiable and systematic.

171 Answer of PJM Interconnection, L.L.C. to Protests and Comments, Docket No. ER16-372-002 (October 7, 2016) at P 11 ("October 7th Filing").
172 Protest of the Independent Market Monitor for PJM, Docket No. ER16-372-002 (September 16, 2016) at P 8 ("September 16th Filing").
173 October 7th Filing at P12; 158 FERC ¶ 61,133 at P 57 (2017).
174 September 16th Filing at P 8.

Not all FCPs approved by PJM met the standard of the PJM tariff. The tariff standards that some fuel cost policies did not meet are:[175] accuracy (reflect applicable costs accurately); and fuel contracts (reflect the market seller's applicable commodity and/or transportation contracts where it holds such contracts).

The MMU failed FCPs not related to natural gas submitted by some market sellers because they do not accurately describe the short run marginal cost of fuel. Some policies include contractual terms (in dollars per MWh or in dollars per MMBtu) that do not reflect the actual cost of fuel. The MMU determined that the terms used in these policies do not reflect the cost of fuel based on the information provided by the market sellers and information gathered by the MMU for similar units.

The MMU failed the remaining FCPs because they do not accurately reflect the cost of natural gas. The main issues identified by the MMU in the natural gas policies were the use of unverifiable fuel costs and the use of available market information that results in inaccurate expected costs.

Some of the failed fuel cost polices include unverifiable cost estimates. Some policies include options under which the estimate of the natural gas commodity cost can be calculated by the market seller without specifying a verifiable, systematic method. For example, some FCPs specify that the source of the natural gas cost would be communications with traders within the market seller's organization. A fuel cost from discretionary and undocumented decision making within the market seller's organization is not verifiable. The point of FCPs is to eliminate such practices as the basis for fuel costs, as most companies have done. Verifiability requires that fuel cost estimates be transparently derived from market information and that PJM or the MMU could reproduce the same fuel cost estimates after the fact by applying the methods documented in the FCP to the same inputs. Verifiable is a key requirement of an FCP. If it is not verifiable, an FCP is meaningless and has no value. Unverifiable fuel costs permit the exercise of market power.

Some of the failed fuel cost polices include the use of available market information that results in inaccurate expected costs because the information does not represent a cleared market price. Some market sellers include the use of offers to sell natural gas on ICE as the sole basis for the cost of natural gas. An offer to sell is generally not a market clearing price and is not an accurate indication of the expected fuel cost. The price of uncleared offers on the exchange generally exceeds the price of cleared transactions, often by a wide margin. Use of sell offers alone is equivalent to using the supply curve alone to determine the market price of a good without considering the demand curve. It is clearly incorrect.

The FCPs that failed the MMU's evaluation also fail to meet the standards defined in the PJM tariff. PJM should not have approved noncompliant fuel cost policies. The MMU recommends that PJM require that all fuel cost policies be algorithmic, verifiable, and systematic.

Cost-Based Offer Penalties

Market Sellers are assessed penalties when they submit cost-based offers that do not comply with Schedule 2 of the PJM Operating Agreement and PJM Manual 15.[176] Penalties are assessed when both PJM and the MMU are in agreement.

In the first nine months of 2021, 118 penalty cases were identified, 89 resulted in assessed cost-based offer penalties, five resulted in disagreement between the MMU and PJM, and 24 remain pending PJM's determination. The five disagreements in 2021 between the MMU and PJM are related to calculation of fuel costs during pipeline constrained situations. These cases were for 114 units owned by 18 different companies. Table 3-116 shows the penalties by the year in which participants were notified.

175 See PJM Operating Agreement Schedule 2 § 2.3 (a).

176 See OA Schedule 2 § 6.

Table 3-115 Cost-based offer penalty cases by year notified: May 2017 through September 2021

Year notified	Cases	Assessed penalties	MMU and PJM Disagreement	Pending cases	Number of units impacted	Number of companies impacted
2017	57	56	1	0	55	16
2018	187	161	26	0	138	35
2019	57	57	0	0	57	19
2020	142	136	5	1	124	25
2021	118	89	5	24	114	18
Total	561	499	37	25	386	58

Since 2017, 561 penalty cases have been identified, 499 resulted in assessed cost-based offer penalties, 37 resulted in disagreement between the MMU and PJM, and 25 remain pending PJM's determination. The 499 cases were from 386 units owned by 58 different companies. The total penalties were $3.5 million, charged to units that totaled 110,151 available MW. The average penalty was $1.46 per available MW. This means that a 100 MW unit would have paid a penalty of $3,505.[177] Table 3-116 shows the total cost-based offer penalties since 2017 by year.

Table 3-116 Cost-based offer penalties by year: May 2017 through September 2021

Year	Number of units	Number of companies	Penalties	Average Available Capacity Charged (MW)	Average Penalty ($/MW)
2017	92	20	$556,826	16,930	$1.56
2018	127	34	$1,265,698	26,343	$2.27
2019	79	20	$490,926	19,798	$1.10
2020	139	27	$412,859	22,467	$0.84
2021	97	19	$812,649	24,613	$1.42
Total	534	60	$3,538,958	110,151	$1.46

The incorrect cost-based offers resulted from incorrect application of Fuel Cost Policies, lack of approved fuel cost policies, fuel cost policy violations, miscalculation of no load costs, inclusion of prohibited maintenance costs, use of incorrect incremental heat rates, use of incorrect start cost, and use of incorrect emission costs.

177 Cost-based offer penalties are assessed by hour. Therefore, a $1 per available MW penalty results in a total of $24 for a 1 MW unit if the violation is for the entire day.

2020 Fuel Cost Policy Changes

On July 28, 2020, the Commission approved tariff revisions that modified the fuel cost policy process and the cost-based offer penalties.[178]

The tariff revisions replaced the annual review process with a periodic review set by PJM. The revisions reinstated the periodic review process employed by the MMU prior to PJM's involvement in the review and approval of fuel cost policies. Monitoring participant behavior through the use of fuel cost policies is an ongoing process that necessitates frequent updates. Market sellers must revise their fuel cost policies whenever circumstances change that impact fuel pricing (e.g. different pricing points, dual fuel addition capability).

The tariff revisions removed the requirement for units with zero marginal cost to have an approved fuel cost policy but also included a zero offer cap for cost-based offers for units that do not have an approved fuel cost policy.

The tariff revisions allow a temporary cost offer method for units that do not have an approved fuel cost policy. The revisions allow units to submit nonzero cost-based offers without an approved fuel cost policy if they follow the temporary cost offer method. The use of the method results in cost-based offers that do not follow the fuel cost policy rules. The approach significantly weakens market power mitigation by allowing market sellers to make offers without an approved fuel cost policy. The proposed approach allows the use of an inaccurate and unsupported fuel cost calculation in place of an accurate fuel cost policy.

The MMU recommends that the temporary cost method be removed and that all units that submit nonzero cost-based offers be required to have an approved fuel cost policy.

The tariff revisions replace the fuel cost policy revocation provision with the ability for PJM to terminate fuel cost policies.

The tariff revisions reduce the penalties for noncompliant cost-based offers in two situations. When market sellers report their noncompliant cost-based

178 172 FERC ¶ 61,094.

offers, the penalty is reduced by 75 percent. When market sellers do not meet conditions defined to measure a potential market impact the penalty is reduced by 90 percent. The conditions include if the market seller failed the TPS test, if the unit was committed on its cost-based offer, if the unit was marginal or if the unit was paid uplift.

The tariff revisions eliminate penalties entirely when units submit noncompliant cost-based offers if PJM determines that an unforeseen event hindered the market seller's ability to submit a compliant cost-based offer. This new provision allows market sellers to not follow their fuel cost policy, submit cost-based offers that are not verifiable or systematic and not face any penalties for doing so.

The MMU recommends that the penalty exemption provision be removed and that all units that submit nonzero cost-based offers be required to follow their approved fuel cost policy.

Cost Development Guidelines

The Cost Development Guidelines contained in PJM Manual 15 do not clearly or accurately describe the short run marginal cost of generation. The MMU recommends that PJM Manual 15 be replaced with a straightforward description of the components of cost-based offers based on short run marginal costs and the correct calculation of cost-based offers.

Variable Operating and Maintenance Costs

PJM Manual 15 and the PJM Operating Agreement Schedule 2 include rules related to VOM costs. On October 29, 2018, PJM filed tariff revisions changing the rules related to VOM costs.[179] The changes proposed by PJM attempted but failed to clarify the rules. The proposed rules defined all costs directly related to electricity production as includable in cost-based offers. This also included the long term maintenance costs of combined cycles and combustion turbines, which had been explicitly excluded in PJM Manual 15.

179 See PJM Interconnection Maintenance Adder Revisions to the Amended and Restated Operating Agreement, L.L.C., Docket No. EL19-8-000.

On April 15, 2019, FERC accepted PJM's filing order, subject to revisions requested by FERC.[180] On October 28, 2019, FERC issued a final order accepting PJM's compliance filing.[181] Regardless of the changes, the rules remain unclear and are now inconsistent with economic theory and effective market power mitigation and competitive market results.

Maintenance costs are not short run marginal costs. Generators perform maintenance during outages. Generators do not perform maintenance in the short run, while operating the generating unit. Generators do not perform maintenance in real time to increase the output of a unit. Some maintenance costs are correlated with the historic operation of a generator. Correlation between operating hours or starts and maintenance expenditures over a long run, multiyear time frame does not indicate the necessity of any specific maintenance expenditure to produce power in the short run.

A generating unit does not consume a defined amount of maintenance parts and labor in order to start. A generating unit does not consume a defined amount of maintenance parts and labor in order to produce an additional MWh. Maintenance events do not occur in the short run. The company cannot optimize its maintenance costs in the short run.

PJM allows for the calculation of VOM costs in dollars per MWh, dollars per MMBtu, dollars per run hour, dollars per equivalent operating hour (EOH) and dollars per start. The MMU converted all VOM costs into dollars per MWh using the units' heat rates, the average economic maximum and average minimum run time of the units in 2020.

The average variable operating and maintenance cost approved by PJM for combustion turbines and diesels for 2020 was 16 percent lower than the approved variable operating and maintenance cost approved by PJM in 2019.[182]

180 167 FERC ¶ 61,030.
181 168 FERC ¶ 61,134.
182 PJM reviews VOM once per year. The results reflect PJM's most recent review.

The average variable operating and maintenance cost approved by PJM for combined cycles for 2020 was seven percent higher than the approved variable operating and maintenance cost approved by PJM in 2019.

The average variable operating and maintenance cost approved by PJM for coal units for 2020 was 8 percent lower than the approved variable operating and maintenance cost approved by PJM in 2019.

Table 3-117 shows the amount of capacity offered within several ranges of VOM costs. Table 3-117 shows that 1,000 MW have an approved effective VOM above $100 per MWh and 3,146 MW have an approved effective VOM between $50 and $100 per MWh.

Table 3-117 2019/2020 and 2020/2021 Approved Effective VOM Costs

	Offered MW	
Approved VOM Range ($/MWh)	2019/2020	2020/2021
$0 to $5 per MWh	69,025	71,898
$5 to $10 per MWh	37,325	30,325
$10 to $20 per MWh	14,276	15,931
$20 to $50 per MWh	5,402	4,938
$50 to $100 per MWh	2,302	3,146
Above $100 per MWh	1,159	1,044

High VOM levels allow generators to economically withhold energy and to exercise market power even when offers are capped at the cost-based offer to mitigate market power. The MMU recommendation to limit cost-based offers to short run marginal costs would prevent such withholding. When units are not committed due to high VOM costs and instead a unit with higher short run marginal costs is committed, the market outcome is inefficient. When units that fail the TPS test are committed on their price-based offer when their short run marginal cost is lower, the market outcome is inefficient.

MMU analysis shows that as CTs, CCs and coal units run for more hours, the VOM cost approved by PJM decreases. This is an indication that fixed costs are included in VOM costs. Fuel costs per MWh remain constant or increase as run hours and the heat rate increase. Fixed costs should not be includable in cost-based energy offers.

The level of costs accepted by PJM for inclusion in VOM depends on PJM's interpretation of the maintenance activities or expenses directly related to electricity production and the level of detailed support provided by market sellers to PJM.

PJM's VOM review is not adequate to determine whether all costs included in VOM are compliant. PJM's VOM review focuses only on the expenses submitted for the last year of up to 20 years of data and PJM's review is dependent on the level of detail provided by the market seller. Recent changes in PJM's review process, triggered by MMU questions, required more details from market sellers and have led to the appropriate exclusion of expenses that were previously included.[183]

The flaws in PJM's review process for VOM are compounded by the ambiguity in the criteria used to determine if costs are includable. PJM's definition of allowable costs for cost-based offers, "costs resulting from electric production," is so broad as to be meaningless. Most costs incurred at a generating station result from electric production in one way or another. The generator itself would not exist but for the need for electric production. PJM's broad definition cannot identify which costs associated with electric production are includable in cost-based offers. The definition is not verifiable or systematic and permits wide discretion by PJM and generators.

The MMU recommends that market participants be required to document the amount and cost of consumables used when operating in order to verify that the total operating cost is consistent with the total quantity used and the unit characteristics.

The MMU recommends, given that maintenance costs are currently allowed in cost-based offers, that market participants be permitted to include only variable maintenance costs, linked to verifiable operational events and that can be supported by clear and unambiguous documentation of operational data (e.g. run hours, MWh, MMBtu) that support the maintenance cycle of the equipment being serviced/replaced.

183 See "Maintenance Adder & Operating Cost Submission Process," 55-57 PJM presentation to the Tech Change Forum. (April 21, 2020) <https://pjm.com/-/media/committees-groups/forums/tech-change/2020/20200421-special/20200421-item-01-maintenance-adder-and-operating-cost-submission-process.ashx>.

The MMU understands that companies have different document retention policies but in order to be allowed to include maintenance costs, such costs must be verified, and they cannot be verified without documentation. Supporting documentation includes internal financial records, maintenance project documents, invoices, and contracts. Market participants should be required to provide the operational data (e.g. run hours, MWh, MMBtu) that supports the maintenance cycle of the equipment being serviced/replaced. For example, if equipment is serviced every 5,000 run hours, the market participant must include at least 5,000 run hours of historical operation in its maintenance cost history.

FERC System of Accounts

PJM Manual 15 relies on the FERC System of Accounts, which predates markets and does not define costs consistent with market economics. Market sellers should not rely solely on the FERC System of Accounts for the calculation of their variable operating and maintenance costs. The FERC System of Accounts does not differentiate between short run marginal costs and avoidable costs. The FERC System of Accounts does not differentiate between costs directly related to energy production and costs not directly related to energy production. Reliance on the FERC System of Accounts for the calculation of variable operating and maintenance costs is likely to lead to incorrect, overstated costs.

The MMU recommends removal of all references to and reliance on the FERC System of Accounts in PJM Manual 15.

Cyclic Starting and Peaking Factors

The use of cyclic starting and peaking factors for calculating VOM costs for combined cycles and combustion turbines is designed to allocate a greater proportion of long term maintenance costs to starts and the tail block of the incremental offer curve. The use of such factors is not appropriate given that long term maintenance costs are not short run marginal costs and should not be included in cost offers. PJM Manual 15 allows for a peaking cyclic factor of three, which means that a unit with a $300 per hour (EOH) VOM cost can add $180 per MWh to a 5 MW peak segment.[184]

184 The peak adder is equal to $300 times three divided by 5 MW.

The MMU recommends the removal of all cyclic starting and peaking factors from PJM Manual 15.

Labor Costs

PJM Manual 15 allows for the inclusion of plant staffing costs in energy market cost offers. This is inappropriate given that labor costs are not short run marginal costs.

The MMU recommends the removal of all labor costs from the PJM Manual 15.

Combined Cycle Start Heat Input Definition

PJM Manual 15 defines the start heat input of combined cycles as the amount of fuel used from the firing of the first combustion turbine to the close of the steam turbine breaker plus any fuel used by other combustion turbines in the combined cycle from firing to the point at which the HRSG steam pressure matches the steam turbine steam pressure. This definition is inappropriate given that after each combustion turbine is synchronized, some of the fuel is used to produce energy for which the unit is compensated in the energy market. To account for this, PJM Manual 15 requires reducing the station service MWh used during the start sequence by the output in MWh produced by each combustion turbine after synchronization and before the HRSG steam pressure matches the steam turbine steam pressure. The formula and the language in this definition are not appropriate and are unclear.

The MMU recommends changing the definition of the start heat input for combined cycles to include only the amount of fuel used from firing each combustion turbine in the combined cycle to the breaker close of each combustion turbine. This change will make the treatment of combined cycles consistent with steam turbines. Exceptions to this definition should be granted when the amount of fuel used from synchronization to steam turbine breaker close is greater than the no load heat plus the output during this period times the incremental heat rate.

Nuclear Costs

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

The MMU recommends the removal of nuclear fuel and nonfuel operations and maintenance costs that are not short run marginal costs from the PJM Manual 15.

Pumped Hydro Costs

The calculation of pumped hydro costs for energy storage in Section 7.3 of PJM Manual 15 is inaccurate. The mathematical formulation does not take into account the purchase of power for pumping in the day-ahead market.

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

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

The rules for determining the qualification of a unit as an FMU or AU became effective November 1, 2014. 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 units eligible for an FMU or AU adder for the period between December 2014 and August 2019.[185] One unit qualified for an FMU adder for the months of September and October, 2019. In 2020, five units qualified for an FMU adder in at least one month. In the first nine months of 2021, one unit qualified for an FMU adder in January.

Table 3-118 shows, by month, the number of FMUs and AUs from January 2020 through September 2021. For example, in September 2020, there was one FMU and AU in Tier 1, zero FMUs and AUs in Tier 2, and two FMUs and AUs in Tier 3.

185 For a definition of FMUs and AUs, and for historical FMU/AU results, see the *2018 State of the Market Report for PJM*, Volume 2, Section 3, Energy Market, at Frequently Mitigated Units (FMU) and Associated Units (AU).

Table 3-118 Number of frequently mitigated units and associated units (By month): January 2020 through September 2021

	2020				2021			
	Tier 1	Tier 2	Tier 3	Total Eligible for Any Adder	Tier 1	Tier 2	Tier 3	Total Eligible for Any Adder
January	0	0	0	0	0	1	0	1
February	0	0	0	0	0	0	0	0
March	0	0	0	0	0	0	0	0
April	0	0	0	0	0	0	0	0
May	0	0	0	0	0	0	0	0
June	2	0	0	2	0	0	0	0
July	2	0	0	2	0	0	0	0
August	1	0	0	1	0	0	0	0
September	1	0	2	3	0	0	0	0
October	2	0	2	4				
November	2	1	2	5				
December	2	1	2	5				

Effective in the 2020/2021 planning year, default Avoidable Cost Rates are no longer defined in the tariff. If a generating unit's Projected PJM Market Revenues plus the unit's PJM capacity market revenues on a rolling 12-month basis (in $/MW-year) are greater than zero, and if the generating unit does not have an approved unit specific Avoidable Cost Rate, the generating unit does not qualify as an FMU as the Avoidable Cost Rate will be assumed to be zero for FMU qualification purposes.

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.

Market Performance

Ownership of Marginal Resources

Table 3-119 shows the contribution to real-time, load-weighted LMP by individual marginal resource owners.[186] The contribution of each marginal resource to price at each load bus is calculated for each five-minute interval of the first nine months of 2021, and summed by the parent company that offers the marginal resource into the real-time energy market. In the first nine

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

months of 2021, the offers of one company resulted in 12.2 percent of the real-time, load-weighted PJM system LMP and the offers of the top four companies resulted in 12.7 percent of the real-time, load-weighted, average PJM system LMP. In the first nine months of 2021, the offers of one company resulted in 12.9 percent of the peak hour real-time, load-weighted PJM system LMP.

Table 3-119 Marginal unit contribution to real-time, load-weighted LMP (By parent company): January through September, 2020 and 2021

2020 (Jan - Sep)						2021 (Jan - Sep)					
All Hours			Peak Hours			All Hours			Peak Hours		
Company	Percent of Price	Cumulative Percent	Company	Percent of Price	Cumulative Percent	Company	Percent of Price	Cumulative Percent	Company	Percent of Price	Cumulative Percent
1	15.2%	15.2%	1	15.3%	15.3%	1	12.2%	12.2%	1	12.9%	12.9%
2	11.4%	26.6%	2	13.4%	28.7%	2	10.4%	22.6%	2	11.1%	24.0%
3	10.5%	37.0%	3	9.6%	38.2%	3	10.2%	32.8%	3	10.7%	34.7%
4	6.7%	43.7%	4	6.1%	44.4%	4	9.9%	42.7%	4	9.3%	44.0%
5	6.2%	49.9%	5	6.0%	50.4%	5	5.8%	48.6%	5	5.0%	49.0%
6	6.1%	55.9%	6	6.0%	56.3%	6	5.0%	53.6%	6	4.7%	53.7%
7	4.7%	60.6%	7	5.2%	61.6%	7	3.7%	57.2%	7	4.4%	58.1%
8	4.6%	65.3%	8	3.4%	64.9%	8	3.5%	60.7%	8	4.0%	62.1%
9	2.9%	68.2%	9	3.1%	68.1%	9	3.3%	64.0%	9	3.5%	65.6%
Other (73 companies)	31.8%	100.0%	Other (68 companies)	31.9%	100.0%	Other (74 companies)	36.0%	100.0%	Other (74 companies)	34.4%	100.0%

Figure 3-62 shows the marginal unit contribution to the real-time, load-weighted PJM system LMP summed by parent companies since 2012.

Figure 3-62 Marginal unit contribution to real-time, load-weighted LMP (By parent company): January through September, 2012 through 2021

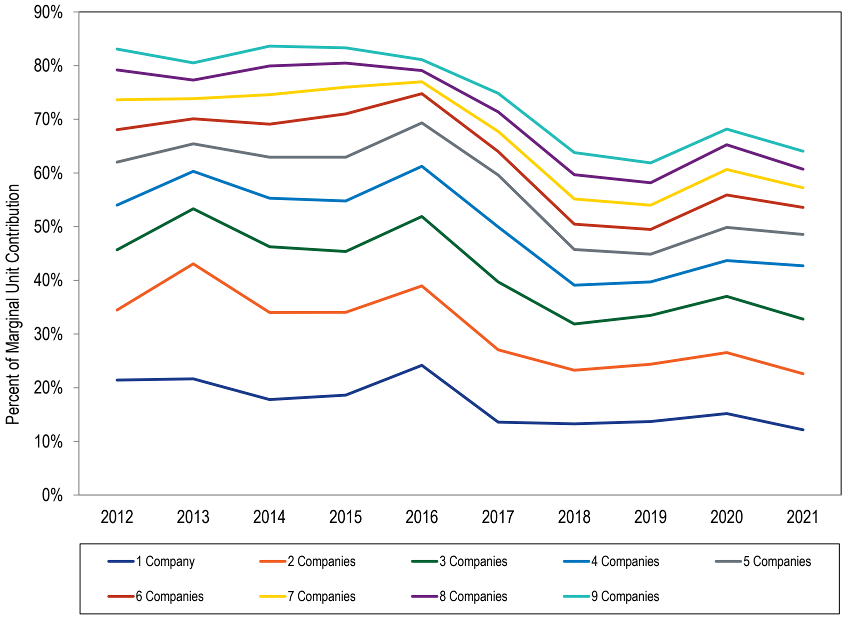


Table 3-120 shows the contribution to day-ahead, load-weighted LMP by individual marginal resource owners.[187] The contribution of each marginal resource to price at each load bus is calculated hourly, and summed by the parent company that offers the marginal resource into the day-ahead energy market. The results show that in the first nine months of 2021, the offers of one company contributed 6.1 percent of the day-ahead, load-weighted, PJM system LMP and that the offers of the top four companies contributed 23.0 percent of the day-ahead, load-weighted, average, PJM system LMP.

Table 3-120 Marginal resource contribution to day-ahead, load-weighted LMP (By parent company): January through September, 2020 and 2021

2020 (Jan - Sep)						2021 (Jan - Sep)					
All Hours			Peak Hours			All Hours			Peak Hours		
Company	Percent of Price	Cumulative Percent	Company	Percent of Price	Cumulative Percent	Company	Percent of Price	Cumulative Percent	Company	Percent of Price	Cumulative Percent
1	10.6%	10.6%	1	11.3%	11.3%	1	6.1%	6.1%	1	7.4%	7.4%
2	10.5%	21.1%	2	11.2%	22.5%	2	6.0%	12.1%	2	7.4%	14.8%
3	7.1%	28.2%	3	10.3%	32.8%	3	5.8%	17.9%	3	4.4%	19.2%
4	5.2%	33.5%	4	6.3%	39.1%	4	5.1%	23.0%	4	4.2%	23.4%
5	4.9%	38.4%	5	4.6%	43.7%	5	4.7%	27.7%	5	4.1%	27.4%
6	4.1%	42.5%	6	4.4%	48.1%	6	4.6%	32.3%	6	4.1%	31.5%
7	3.8%	46.3%	7	4.2%	52.2%	7	4.0%	36.3%	7	4.0%	35.5%
8	3.7%	50.0%	8	3.4%	55.7%	8	3.6%	39.9%	8	3.9%	39.4%
9	3.7%	53.8%	9	3.0%	58.6%	9	3.5%	43.5%	9	3.8%	43.1%
Other (141 companies)	46.2%	100.0%	Other (139 companies)	41.4%	100.0%	Other (142 companies)	56.5%	100.0%	Other (137 companies)	56.9%	100.0%

Markup

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

The MMU calculates an explicit measure of the impact of marginal unit incremental energy offer markups on LMP using the mathematical relationships among LMPs in the market solution.[188] The markup impact calculation sums, over all marginal units, the product of the dollar markup of the unit and the marginal impact of the unit's offer on the system load-weighted LMP. The markup impact includes the impact of the identified markup behavior of all marginal units. Positive and negative markup impacts may offset one another. The markup analysis is a direct measure of market performance. It does not take into account whether or not marginal units have either locational or aggregate structural market power.

The markup calculation is not based on a counterfactual 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. 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

187 Id.

188 The MMU calculates the impact on system prices of marginal unit price-cost markup, based on analysis using sensitivity factors. The calculation shows the markup component of LMP based on a comparison between the price-based incremental energy offer and the cost-based incremental energy offer of each actual marginal unit on the system. This is the same method used to calculate the fuel cost adjusted LMP and the components of LMP. The markup analysis does not include markup in start up or no load offers. *See* Calculation and Use of Generator Sensitivity/Unit Participation Factors, 2010 State of the Market Report for PJM: Technical Reference for PJM Markets.

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.

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.

PJM implemented fast start pricing on September 1, 2021. Under the fast start pricing rules, the LMPs are calculated in the pricing run, where the offer price of a marginal fast start unit includes amortized commitment costs. For all the fast start marginal units starting from September 1, 2021, the markup includes markup in the incremental offer, markup in the amortized start up offer and markup in the amortized no load offer.

Table 3-121 shows the impact (markup component of LMP) of the marginal unit markup behavior by fuel type and unit type on the real-time, load-weighted, average system LMP, using unadjusted and adjusted offers. The adjusted markup component of LMP increased from $2.25 per MWh in the first nine months of 2020 to $3.60per MWh in the first nine months of 2021. The adjusted markup contribution of coal units in the first nine months of 2021 was $0.78 per MWh. The adjusted markup component of gas fired units in the first nine months of 2021 was $2.89 per MWh, an increase of $0.83 per MWh from the first nine months of 2020. The markup component of wind units was less than $0.0 per MWh. If a price-based offer is negative, but less negative than a cost-based offer, the markup is positive. In the first nine months of 2021, among the wind units that were marginal, 77.8 percent had negative offer prices.

Table 3-121 Markup component of real-time, load-weighted, average LMP by primary fuel type and unit type: January through September, 2020 and 2021[189]

		2020 (Jan - Sep)		2021 (Jan - Sep)	
Fuel	Technology	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)
Coal	Steam	($0.42)	$0.22	$0.28	$0.78
Gas	CC	$0.91	$1.69	$0.63	$1.94
Gas	CT	$0.25	$0.40	$0.47	$0.91
Gas	RICE	$0.03	$0.04	($0.00)	$0.01
Gas	Steam	($0.11)	($0.06)	($0.01)	$0.04
Landfill Gas	CT	$0.00	$0.00	($0.00)	($0.00)
Municipal Waste	RICE	$0.00	$0.00	$0.00	$0.00
Oil	CC	$0.00	$0.00	$0.00	$0.00
Oil	CT	($0.00)	($0.00)	($0.00)	$0.01
Oil	RICE	$0.00	$0.00	$0.00	$0.00
Oil	Steam	($0.04)	($0.04)	($0.08)	($0.07)
Other	Steam	($0.00)	($0.00)	$0.01	$0.02
Wind	Wind	($0.00)	($0.00)	($0.04)	($0.04)
Total		$0.61	$2.25	$1.25	$3.60

Markup Component of Real-Time Price

Table 3-122 shows the markup component, calculated using unadjusted offers, of average prices and of average monthly on peak and off peak prices. Table 3-123 shows the markup component, calculated using adjusted offers, of average prices and of average monthly on peak and off peak prices. In the first nine months of 2021, when using unadjusted cost-based offers, 1.25 per MWh of the PJM real-time, load-weighted, average LMP was attributable to markup. Using adjusted cost-based offers, $3.60 per MWh of the PJM real-time, load-weighted, average LMP was attributable to markup. In the first nine months of 2021, the peak markup component was highest in August, $2.71 per MWh using unadjusted cost-based offers and peak markup component was highest in June, $5.27 per MWh using adjusted cost-based offers. This corresponds to 11.8 percent and 17.5 percent of the real-time, peak, load-weighted, average LMP in August.

189 The unit type RICE refers to Reciprocating Internal Combustion Engines.

Table 3-122 Monthly markup components of real-time, load-weighted, LMP (Unadjusted): January 2020 through September 2021

	2020			2021		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
Jan	$0.49	$0.94	$0.03	($0.46)	($0.30)	($0.60)
Feb	($0.15)	($0.00)	($0.28)	($0.53)	$0.06	($1.12)
Mar	($0.09)	$0.46	($0.66)	$0.02	$0.16	($0.13)
Apr	($0.07)	$0.17	($0.33)	($1.69)	($2.56)	($0.72)
May	$0.54	$1.03	$0.10	($0.02)	$0.62	($0.62)
Jun	$1.24	$2.02	$0.30	$1.75	$2.76	$0.58
Jul	$0.83	$1.75	($0.30)	$2.61	$3.37	$1.80
Aug	$1.80	$2.88	$0.70	$4.83	$6.68	$2.71
Sep	$0.47	$0.97	($0.08)	$3.30	$4.19	$2.34
Oct	$0.09	$0.71	($0.57)			
Nov	($0.01)	$0.72	($0.68)			
Dec	$0.37	$0.37	$0.37			
Total	$0.50	$1.08	($0.10)	$1.25	$1.93	$0.53

Table 3-123 Monthly markup components of real-time, load-weighted, LMP (Adjusted): January 2020 through September 2021

	2020			2021		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
Jan	$2.21	$2.80	$1.60	$1.47	$1.73	$1.24
Feb	$1.57	$1.85	$1.30	$2.41	$3.21	$1.60
Mar	$1.44	$2.07	$0.81	$1.63	$1.85	$1.39
Apr	$1.43	$1.73	$1.11	($0.08)	($0.97)	$0.91
May	$1.98	$2.65	$1.39	$1.93	$2.75	$1.17
Jun	$2.77	$3.75	$1.58	$3.96	$5.22	$2.52
Jul	$2.70	$3.81	$1.33	$5.11	$6.20	$3.95
Aug	$3.61	$4.83	$2.35	$7.75	$9.92	$5.27
Sep	$1.89	$2.50	$1.22	$6.52	$7.71	$5.23
Oct	$1.76	$2.51	$0.95			
Nov	$1.68	$2.53	$0.88			
Dec	$2.46	$2.56	$2.37			
Total	$2.19	$2.90	$1.44	$3.60	$4.50	$2.66

Hourly Markup Component of Real-Time Prices

Figure 3-63 shows the markup contribution to the hourly load-weighted, LMP using unadjusted cost offers in 2020 and the first nine months of 2021. Figure 3-64 shows the markup contribution to the hourly load-weighted, LMP using adjusted cost-based offers in 2020 and the first nine months of 2021.

Figure 3-63 Markup contribution to real-time, hourly, load-weighted LMP (Unadjusted): 2020 through September 2021

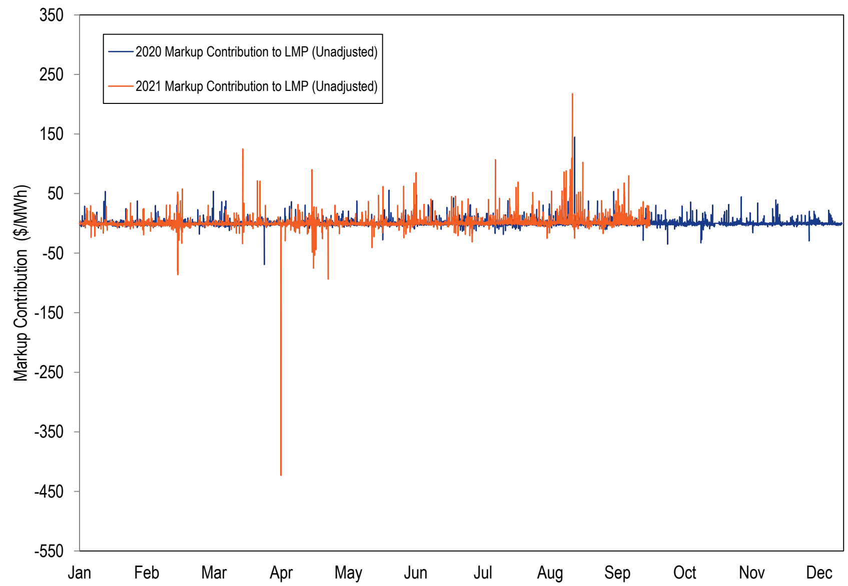


Figure 3-64 Markup contribution to real-time, hourly, load-weighted, LMP (Adjusted): 2020 through September 2021

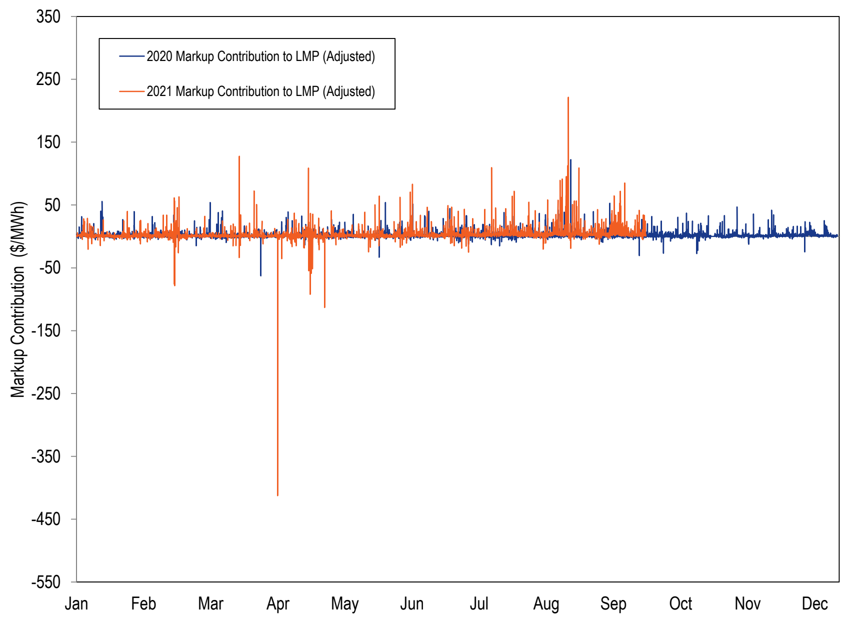


Table 3-124 Average, real-time, zonal markup component (Unadjusted): January through September, 2020 and 2021

	2020 (Jan - Sep)			2021 (Jan - Sep)		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
ACEC	$0.16	$0.38	($0.06)	$0.80	$1.44	$0.15
AEP	$0.23	$0.52	($0.08)	$1.34	$2.08	$0.58
APS	$0.26	$0.59	($0.09)	$1.31	$2.04	$0.56
ATSI	$0.26	$0.55	($0.05)	$1.38	$2.06	$0.67
BGE	$0.37	$0.78	($0.06)	$1.57	$2.31	$0.81
COMED	$0.17	$0.50	($0.19)	$1.34	$2.13	$0.54
DAY	$0.26	$0.55	($0.06)	$1.40	$2.11	$0.68
DOM	$0.23	$0.54	($0.09)	$1.29	$2.06	$0.50
DPL	$0.13	$0.37	($0.12)	$1.01	$1.74	$0.26
DUKE	$0.24	$0.54	($0.08)	$1.31	$1.97	$0.63
DUQ	$0.30	$0.64	($0.06)	$1.30	$1.94	$0.64
EKPC	$0.22	$0.54	($0.11)	$1.29	$1.96	$0.61
JCPLC	$0.16	$0.36	($0.05)	$0.89	$1.47	$0.28
MEC	$0.16	$0.37	($0.07)	$1.33	$2.27	$0.35
OVEC	$0.12	$0.43	($0.16)	$1.30	$1.80	$0.78
PE	$0.21	$0.45	($0.06)	$1.27	$2.03	$0.48
PECO	$0.14	$0.38	($0.11)	$0.85	$1.52	$0.16
PEPCO	$0.30	$0.65	($0.07)	$1.58	$2.20	$0.95
PPL	$0.15	$0.28	$0.01	$1.03	$1.73	$0.31
PSEG	$0.15	$0.37	($0.08)	$0.97	$1.58	$0.34
REC	$0.12	$0.31	($0.09)	$1.28	$2.05	$0.49

Markup Component of Real-Time Zonal Prices

The unit markup component of average real-time price using unadjusted offers is shown for each zone in the first nine months of 2020 and the first nine months of 2021 in Table 3-124 and for adjusted offers in Table 3-125.[190] The smallest zonal all hours average markup component using unadjusted offers in the first nine months of 2021, was in the ACEC Control Zone, 0.80 per MWh, while the highest was in the PEPCO Control Zone, $1.58 per MWh. The smallest zonal on peak average markup component using unadjusted offers in the first nine months of 2021, was in the ACEC Control Zone, 1.44 per MWh, while the highest was in the BGE Control Zone, $2.31 per MWh.

190 A marginal unit's offer price affects LMPs in the entire PJM market. The markup component of average zonal real-time price is based on offers of units located within the zone and units located outside the transmission zone.

Table 3-125 Average, real-time, zonal markup component (Adjusted): January through September, 2020 and 2021

	2020 (Jan - Sep)			2021 (Jan - Sep)		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
ACEC	$1.03	$1.28	$0.77	$2.96	$3.74	$2.14
AEP	$1.26	$1.63	$0.88	$3.76	$4.73	$2.75
APS	$1.31	$1.71	$0.89	$3.73	$4.70	$2.73
ATSI	$1.29	$1.66	$0.89	$3.78	$4.69	$2.85
BGE	$1.42	$1.90	$0.91	$4.25	$5.29	$3.19
COMED	$1.10	$1.53	$0.64	$3.68	$4.69	$2.64
DAY	$1.33	$1.69	$0.93	$3.93	$4.90	$2.93
DOM	$1.25	$1.63	$0.86	$3.83	$4.87	$2.75
DPL	$1.08	$1.34	$0.81	$3.20	$4.07	$2.31
DUKE	$1.25	$1.62	$0.86	$3.74	$4.66	$2.80
DUQ	$1.30	$1.72	$0.85	$3.65	$4.49	$2.78
EKPC	$1.27	$1.65	$0.89	$3.70	$4.61	$2.76
JCPLC	$1.07	$1.32	$0.81	$3.07	$3.83	$2.29
MEC	$1.14	$1.40	$0.85	$3.66	$4.86	$2.42
OVEC	$1.21	$1.61	$0.84	$3.66	$4.38	$2.91
PE	$1.21	$1.52	$0.87	$3.59	$4.56	$2.59
PECO	$1.07	$1.34	$0.78	$2.97	$3.80	$2.13
PEPCO	$1.32	$1.74	$0.88	$4.15	$5.03	$3.25
PPL	$1.11	$1.28	$0.91	$3.25	$4.16	$2.30
PSEG	$1.07	$1.34	$0.79	$3.21	$4.04	$2.36
REC	$1.02	$1.26	$0.76	$3.62	$4.69	$2.53

Markup by Real-Time Price Levels

Table 3-126 shows the markup contribution to the LMP, based on the unadjusted cost-based offers and adjusted cost-based offers of the marginal units, when the PJM system wide, load-weighted, average LMP was in the identified price range.

Table 3-126 Real-time markup contribution (By load-weighted, LMP category, unadjusted): January through September, 2020 and 2021

	2020 (Jan - Sep)		2021 (Jan - Sep)	
LMP Category	Markup Component	Frequency	Markup Component	Frequency
< $10	($0.53)	2.5%	($10.48)	0.0%
$10 to $15	($0.22)	25.9%	($1.56)	0.7%
$15 to $20	($0.43)	43.8%	($0.93)	15.6%
$20 to $25	$0.29	18.6%	($0.90)	25.3%
$25 to $50	$2.80	7.9%	$0.32	47.0%
$50 to $75	$7.69	1.0%	$5.37	7.1%
$75 to $100	$5.86	0.2%	$10.93	2.2%
$100 to $125	$6.26	0.0%	$18.34	1.1%
$125 to $150	$1.20	0.0%	$28.61	0.4%
>= $150	$2.85	0.0%	$39.41	0.5%

Table 3-127 Real-time markup contribution (By load-weighted, LMP category, adjusted): January through September, 2020 and 2021

	2020 (Jan - Sep)		2021 (Jan - Sep)	
LMP Category	Markup Component	Frequency	Markup Component	Frequency
< $10	($0.05)	2.6%	($9.88)	0.0%
$10 to $15	$0.41	25.7%	($0.35)	0.7%
$15 to $20	$0.41	44.1%	$0.53	15.6%
$20 to $25	$1.26	18.5%	$0.94	25.3%
$25 to $50	$3.89	7.7%	$2.77	47.0%
$50 to $75	$9.21	1.0%	$8.79	7.1%
$75 to $100	$6.85	0.2%	$15.00	2.2%
$100 to $125	$7.09	0.0%	$22.92	1.1%
$125 to $150	$3.18	0.0%	$33.67	0.4%
>= $150	$3.62	0.0%	$43.08	0.5%

Markup by Company

Table 3-128 shows the markup contribution based on the unadjusted cost-based offers and adjusted cost-based offers to real-time, load-weighted, average LMP by individual marginal resource owners. The markup contribution of each marginal resource to price at each load bus is calculated for each five-minute interval, and summed by the parent company that offers the marginal resource into the real-time energy market. In the first nine months of 2021, when using unadjusted cost-based offers, the markup of one company accounted for 1.4 percent of the load-weighted, average LMP, the markup of the top five companies accounted for 3.8 percent of the load-weighted average LMP and the markup of all companies accounted for 3.5 percent of the load-weighted, average LMP. The top five companies' markup contribution to the load-weighted, average LMP and the dollar values of their markup increased in the first nine months of 2021. The markup contribution to the load-weighted average LMP and share of the markup contribution to the load-weighted average LMP also increased in the first nine months of 2021. The markup contribution of a unit to the real-time, load-weighted, average LMP can be positive or negative.

Table 3-128 Markup component of real-time, load-weighted, average LMP by Company: January through September, 2020 and 2021

	2020 (Jan - Sep)				2021 (Jan - Sep)			
	Markup Component of LMP (Unadjusted)		Markup Component of LMP (Adjusted)		Markup Component of LMP (Unadjusted)		Markup Component of LMP (Adjusted)	
	$/MWh	Percent of Load Weighted LMP	$/MWh	Percent of Load Weighted LMP	$/MWh	Percent of Load Weighted LMP	$/MWh	Percent of Load Weighted LMP
Top 1 Company	$0.41	1.9%	$0.63	3.0%	$0.50	1.4%	$0.70	2.0%
Top 2 Companies	$0.58	2.7%	$0.87	4.1%	$0.89	2.5%	$1.34	3.8%
Top 3 Companies	$0.72	3.4%	$1.10	5.2%	$1.10	3.1%	$1.64	4.6%
Top 4 Companies	$0.83	3.9%	$1.33	6.3%	$1.25	3.5%	$1.94	5.4%
Top 5 Companies	$0.93	4.4%	$1.48	7.0%	$1.37	3.8%	$2.20	6.2%
All Companies	$0.61	2.9%	$2.25	10.6%	$1.24	3.5%	$3.60	10.1%

Day-Ahead Markup

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

The markup component of the PJM day-ahead, load-weighted average LMP by primary fuel and unit type is shown in Table 3-129. INC, DEC and up to congestion transactions (UTC) have zero markups. UTCs were 36.1 percent of marginal resources, INCs were 17.3 percent of marginal resources and DECs were 26.5 percent of marginal resources in the first nine months of 2021.

The adjusted markup of coal, gas and oil units is calculated as the difference between the price-based offer, and the cost-based offer excluding the 10 percent adder. Table 3-129 shows the markup component of LMP for marginal generating resources. Generating resources were only 19.7 percent of marginal resources in the first nine months of 2021. Using adjusted cost-based offers, the markup component of LMP for marginal generating resources increased for coal fired steam units from $0.08 to $0.71 per MWh and increased for gas fired CC units from $0.89 to $1.38 per MWh.

Table 3-129 Markup component of day-ahead, load-weighted, average LMP by primary fuel type and technology type: January through September, 2020 and 2021

		2020 (Jan - Sep)			2021 (Jan - Sep)		
Fuel	Technology	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)	Frequency	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)	Frequency
Coal	Steam	($0.58)	$0.08	34.6%	$0.12	$0.71	34.7%
Gas	CC	$0.49	$0.89	54.6%	$0.42	$1.38	54.5%
Gas	CT	$0.03	$0.05	1.8%	$0.05	$0.05	1.4%
Gas	RICE	($0.00)	($0.00)	0.4%	($0.00)	$0.00	0.7%
Gas	Steam	($0.09)	($0.05)	3.3%	($0.00)	$0.05	3.2%
Municipal Waste	RICE	$0.00	$0.00	0.1%	$0.00	$0.00	0.2%
Oil	CC	$0.00	$0.00	0.0%	$0.00	$0.00	0.0%
Oil	CT	$0.00	$0.00	0.7%	$0.00	$0.00	0.3%
Oil	RICE	$0.00	$0.00	0.0%	$0.00	$0.00	0.1%
Oil	Steam	($0.01)	($0.01)	0.1%	($0.12)	($0.10)	0.2%
Other	Solar	$0.00	$0.00	0.1%	$0.04	$0.04	0.3%
Other	Steam	($0.00)	($0.00)	0.4%	$0.00	$0.00	0.2%
Uranium	Steam	$0.00	$0.00	1.9%	$0.00	$0.00	0.2%
Water	Hydro	$0.00	$0.00	0.0%	$0.00	$0.00	0.0%
Wind	Wind	$0.00	$0.00	1.9%	$0.32	$0.32	3.9%
Total		($0.15)	$0.95	100.0%	$0.84	$2.45	100.0%

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 3-130 shows the markup component of average prices and of average monthly on peak and off peak prices using unadjusted cost-based offers. In the first nine months of 2021, when using unadjusted cost-based offers, $0.84 per MWh of the PJM day-ahead load-weighted, average LMP was attributable to markup. In the first nine months of 2021, the peak markup component was highest in September, $3.44 per MWh using unadjusted cost-based offers.

Table 3-130 Monthly markup components of day-ahead (Unadjusted), load-weighted LMP: January 2020 through September 2021

	2020			2021		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
Jan	($0.03)	$0.29	($0.35)	($0.41)	($0.20)	($0.59)
Feb	($0.24)	($0.08)	($0.39)	($0.30)	$2.25	($2.91)
Mar	($0.21)	($0.19)	($0.23)	$0.62	$0.56	$0.69
Apr	($0.27)	($0.19)	($0.36)	$0.38	$0.84	($0.14)
May	($0.19)	$0.17	($0.52)	$1.05	$1.24	$0.88
Jun	$0.07	$0.39	($0.33)	$0.16	$0.41	($0.13)
Jul	($0.55)	($0.42)	($0.72)	$1.97	$3.20	$0.65
Aug	$0.07	$0.70	($0.59)	$1.59	$2.33	$0.73
Sep	($0.01)	$0.55	($0.63)	$2.31	$3.44	$1.07
Oct	$0.17	$0.51	($0.19)			
Nov	($0.18)	$0.33	($0.67)			
Dec	$0.07	$0.38	($0.24)			
Total	($0.11)	$0.20	($0.44)	$0.84	$1.62	$0.01

Table 3-131 shows the markup component of average prices and of average monthly on peak and off peak prices using adjusted cost-based offers. In the first nine months of 2021, when using adjusted cost-based offers, $2.45 per MWh of the PJM day-ahead, load-weighted, average LMP was attributable to markup. In the first nine months of 2021, the peak markup component was highest in September, $5.11 per MWh using adjusted cost-based offers.

Table 3-131 Monthly markup components of day-ahead (Adjusted), load-weighted, LMP: January 2020 through September 2021

	2020			2021		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
Jan	$1.35	$1.65	$1.03	$1.12	$1.27	$0.99
Feb	$1.03	$1.22	$0.84	$2.16	$4.67	($0.40)
Mar	$0.96	$1.02	$0.90	$1.77	$1.72	$1.82
Apr	$0.70	$0.91	$0.47	$1.64	$1.98	$1.25
May	$0.72	$1.00	$0.47	$2.44	$2.56	$2.33
Jun	$1.04	$1.35	$0.67	$1.48	$1.74	$1.18
Jul	$0.63	$0.73	$0.51	$3.59	$4.73	$2.37
Aug	$1.14	$1.77	$0.48	$3.39	$4.00	$2.68
Sep	$0.95	$1.50	$0.34	$4.21	$5.11	$3.23
Oct	$1.14	$1.39	$0.86			
Nov	$0.93	$1.34	$0.54			
Dec	$1.44	$1.69	$1.18			
Total	$1.01	$1.30	$0.70	$2.45	$3.16	$1.71

Markup Component of Day-Ahead Zonal Prices

The markup component of annual average day-ahead price using unadjusted cost-based offers is shown for each zone in Table 3-132. The markup component of annual average day-ahead price using adjusted cost-based offers is shown for each zone in Table 3-133. The smallest zonal all hours average markup component using adjusted cost-based offers for the first nine months of 2021 was in the DUQ Zone, $1.93 per MWh, while the highest was in the EKPC Control Zone, $3.81 per MWh. The smallest zonal on peak average markup using adjusted cost-based offers was in the DPL Control Zone, $1.97 per MWh, while the highest was in the EKPC Control Zone, $6.11 per MWh.

Table 3-132 Day-ahead, average, zonal markup component (Unadjusted): January through September, 2020 and 2021

	2020 (Jan - Sep)			2021 (Jan - Sep)		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
ACEC	$0.15	$0.45	($0.16)	$0.58	$1.00	$0.14
AEP	($0.31)	($0.03)	($0.60)	$0.78	$1.63	($0.10)
APS	($0.33)	($0.08)	($0.60)	$0.64	$1.48	($0.23)
ATSI	($0.24)	$0.04	($0.56)	$0.27	$0.71	($0.19)
BGE	($0.31)	($0.02)	($0.62)	$1.20	$2.47	($0.13)
COMED	($0.23)	$0.09	($0.58)	$0.73	$1.28	$0.15
DAY	($0.08)	$0.45	($0.67)	$0.99	$1.88	$0.01
DOM	($0.19)	$0.22	($0.62)	$0.94	$1.79	$0.08
DPL	$0.07	$0.24	($0.12)	$0.35	$0.34	$0.36
DUKE	($0.09)	$0.51	($0.75)	$0.88	$1.71	($0.00)
DUQ	($0.40)	($0.18)	($0.63)	$0.33	$0.71	($0.08)
EKPC	($0.22)	$0.20	($0.65)	$2.30	$4.87	($0.30)
JCPLC	$0.07	$0.30	($0.20)	$0.60	$0.97	$0.18
MEC	($0.08)	($0.12)	($0.04)	$0.59	$1.11	$0.03
OVEC	$0.32	$0.69	($0.21)	$0.44	$0.77	($0.05)
PE	($0.01)	$0.19	($0.26)	$0.42	$0.81	($0.02)
PECO	$0.06	$0.27	($0.16)	$0.51	$0.77	$0.23
PEPCO	($0.49)	($0.30)	($0.70)	$1.09	$2.13	($0.03)
PPL	$0.53	$0.69	$0.36	$0.59	$1.02	$0.14
PSEG	$0.05	$0.25	($0.16)	$0.62	$0.94	$0.28
REC	$0.11	$0.38	($0.21)	$0.60	$1.04	$0.09

Table 3-133 Day-ahead, average, zonal markup component (Adjusted): January through September, 2020 and 2021

	2020 (Jan - Sep)			2021 (Jan - Sep)		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
ACEC	$1.24	$1.55	$0.91	$2.34	$2.83	$1.83
AEP	$0.82	$1.06	$0.55	$2.37	$3.13	$1.58
APS	$0.75	$0.98	$0.50	$2.25	$3.00	$1.46
ATSI	$0.89	$1.18	$0.56	$1.96	$2.32	$1.56
BGE	$0.76	$1.03	$0.49	$2.75	$3.82	$1.61
COMED	$0.88	$1.21	$0.51	$2.36	$2.91	$1.78
DAY	$1.11	$1.63	$0.53	$2.66	$3.47	$1.78
DOM	$1.02	$1.54	$0.47	$2.52	$3.17	$1.85
DPL	$1.13	$1.26	$0.98	$1.99	$1.97	$2.00
DUKE	$1.03	$1.58	$0.43	$2.46	$3.18	$1.70
DUQ	$0.66	$0.84	$0.47	$1.93	$2.25	$1.60
EKPC	$0.88	$1.23	$0.51	$3.81	$6.11	$1.49
JCPLC	$1.17	$1.41	$0.89	$2.36	$2.76	$1.90
MEC	$0.94	$0.87	$1.02	$2.13	$2.55	$1.66
OVEC	$1.46	$1.91	$0.82	$2.19	$2.49	$1.75
PE	$1.00	$1.19	$0.76	$2.04	$2.40	$1.63
PECO	$1.13	$1.33	$0.91	$2.22	$2.54	$1.89
PEPCO	$0.59	$0.74	$0.43	$2.68	$3.53	$1.75
PPL	$1.54	$1.70	$1.38	$2.20	$2.60	$1.77
PSEG	$1.13	$1.33	$0.92	$2.37	$2.73	$1.97
REC	$1.17	$1.42	$0.88	$2.28	$2.73	$1.77

Markup by Day-Ahead Price Levels

Table 3-134 and Table 3-135 show the average markup component of LMP, based on the unadjusted cost-based offers and adjusted cost-based offers of the marginal units, when the PJM system LMP was in the identified price range.

Table 3-134 Average, day-ahead markup component (By LMP category, unadjusted): January through September, 2020 and 2021

	2020 (Jan - Sep)		2021 (Jan - Sep)	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $10	($0.01)	1.4%	$0.00	0.0%
$10 to $15	($0.08)	20.4%	($0.00)	0.1%
$15 to $20	($0.21)	41.8%	$0.03	11.4%
$20 to $25	($0.00)	22.3%	($0.06)	25.1%
$25 to $50	$0.15	13.5%	$0.42	52.8%
$50 to $75	$0.00	0.7%	$0.25	8.0%
$75 to $100	$0.00	0.0%	$0.11	1.5%
$100 to $125	$0.00	0.0%	$0.04	0.6%
$125 to $150	$0.00	0.0%	($0.00)	0.3%
>= $150	$0.00	0.0%	$0.06	0.1%

Table 3-135 Average, day-ahead markup component (By LMP category, adjusted): January through September, 2020 and 2021

	2020 (Jan - Sep)		2021 (Jan - Sep)	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $10	$0.00	1.4%	$0.00	0.0%
$10 to $15	$0.07	20.4%	($0.00)	0.1%
$15 to $20	$0.28	41.8%	$0.13	11.4%
$20 to $25	$0.30	22.3%	$0.27	25.1%
$25 to $50	$0.29	13.5%	$1.36	52.8%
$50 to $75	$0.01	0.7%	$0.41	8.0%
$75 to $100	$0.00	0.0%	$0.13	1.5%
$100 to $125	$0.00	0.0%	$0.06	0.6%
$125 to $150	$0.00	0.0%	$0.01	0.3%
>= $150	$0.00	0.0%	$0.06	0.1%

Market Structure, Participant Behavior, and Market Performance

The goal of regulation through competition is to achieve competitive market outcomes even in the presence of market power. Market structure in the PJM energy market is not competitive in local markets created by transmission constraints. At times, market structure is not competitive in the aggregate energy market. Market sellers pursuing their financial interests may choose behavior that benefits from structural market power in the absence of an effective market power mitigation program. The overall competitive assessment evaluates the extent to which that participant behavior results in competitive or above competitive pricing. The competitive assessment brings together the structural measures of market power, HHI and pivotal suppliers, with participant behavior, specifically markup, and pricing outcomes.

HHI and Markup

In theory, the HHI provides insight into the relationship between market structure, behavior, and performance. In the case where participants compete by producing output at constant, but potentially different, marginal costs, the HHI is directly proportional to the expected average price cost markup in the market:[191]

$$\frac{HHI}{\varepsilon} = \frac{P - MC}{P}$$

where ε is the absolute value of the price elasticity of demand, P is the market price, and MC is the average marginal cost of production. This is called the Lerner Index. The left side of the equation quantifies market structure, and the right side of the equation measures market performance. The assumed participant behavior is profit maximization. As HHI decreases, implying a more competitive market, prices converge to marginal cost, the competitive market outcome. But even a low HHI may result in substantial markup with a low price elasticity of demand. If HHI is very high, meaning competition is lacking, prices can reach the monopoly level. Price elasticity of demand (ε) determines the degree to which suppliers with market power can impose

191 *See* Tirole, Jean. *The Theory of Industrial Organization*, MIT (1988), Chapter 5: Short-Run Price Competition.

higher prices on customers. The Lerner Index is a measure of market power that connects market structure (HHI and demand elasticity) to market performance (markup).

The PJM energy market HHIs and application of the FERC concentration categories may understate the degree of market power because, in the absence of aggregate market power mitigation, even the unconcentrated HHI level would imply substantial markups due to the low short run price elasticity of demand. For example, research estimates find short run electricity demand elasticity ranging from -0.2 to -0.4.[192] Using the Lerner Index, the elasticities imply, for example, an average markup ranging from 25 to 50 percent at the unconcentrated to moderately concentrated threshold HHI of 1000:[193]

$$\frac{HHI}{\varepsilon} = \frac{0.1}{0.2} = \frac{P - MC}{P} = 50\%$$

With knowledge of HHI, elasticity, and marginal cost, one can solve for the price level theoretically indicated by the Lerner Index, based on profit maximizing behavior including the exercise of market power. With marginal costs of $43.60 per MWh and an average HHI of 751 in the first nine months of 2021, average PJM prices would theoretically range from $54 to $69 per MWh using the elasticity range of -0.2 to -0.4.[194] The theoretical prices exceed marginal costs because the exercise of market power is profit maximizing in the absence of market power mitigation. Actual prices, averaging $47.73 per MWh in the dispatch run and $49.63 in the pricing run, with markups, at 8.7 percent, are lower than the theoretical range, supporting the MMU's competitive assessment of the market. However, markup is not zero. In some market intervals, markup and prices reach levels that reflect the exercise of market power.

192 See Patrick, Robert H. and Frank A. Wolak (1997), "Estimating the Customer-Level Demand for Electricity Under Real-Time Market Prices," <https://web.stanford.edu/group/fwolak/cgi-bin/sites/default/files/files/Estimating%20the%20Customer-Level%20Demand%20for%20Electricity%20Under%20Real-Time%20Market%20Prices_Aug%201997_Patrick,%20Wolak.pdf>, last accessed August 3, 2018 and Fan, Shu and Rob Hyndman (2010), "The price elasticity of electricity demand in South Australia," <https://robjhyndman.com/papers/Elasticity2010.pdf>.

193 The HHI used in the equation is based on market shares. For the FERC HHI thresholds and standard HHI reporting, market shares are multiplied by 100 prior to squaring the market shares.

194 The average HHI is found in Table 3-1. Marginal costs are the sum of all components of LMP except markup, as shown in Table 3--51.

Market Power Mitigation and Markup

Fully effective market power mitigation would not allow a seller that fails the structural market power test (the TPS test) to set prices with a positive markup. With the flaws in PJM's implementation of the TPS test, resources can and do set prices with a positive markup while failing the TPS test.

Table 3-136 categorizes day-ahead and real-time marginal unit intervals by markup level and TPS test status. In the first nine months of 2021, 4.0 percent of real-time marginal unit intervals and 3.5 percent of day-ahead marginal unit hours included a positive markup even though the resource failed the TPS test for local market power. Unmitigated local market power affects PJM market prices. Zero markup with a TPS test failure indicates the mitigation of a marginal unit.

Table 3-136 Percent of real-time marginal unit intervals with markup and local market power: January through September, 2021

	Day-ahead Market			Real-time Market		
Markup Category	Not Failing TPS Test	Failing TPS Test	Percent in Category	Not Failing TPS Test	Failing TPS Test	Percent in Category
Negative Markup	33.6%	6.8%	40.4%	36.0%	8.9%	44.9%
Zero Markup	20.5%	5.5%	26.0%	16.3%	8.5%	24.8%
$0 to $5	22.2%	2.3%	24.5%	20.4%	2.5%	22.9%
$5 to $10	3.5%	0.4%	3.9%	3.0%	0.5%	3.5%
$10 to $15	1.3%	0.3%	1.6%	0.9%	0.2%	1.1%
$15 to $20	1.9%	0.1%	2.0%	0.7%	0.1%	0.8%
$20 to $25	0.4%	0.2%	0.5%	0.3%	0.1%	0.4%
$25 to $50	0.5%	0.2%	0.7%	0.7%	0.3%	1.0%
$50 to $75	0.4%	0.1%	0.4%	0.1%	0.1%	0.2%
$75 to $100	0.1%	0.0%	0.1%	0.1%	0.0%	0.2%
Above $100	0.0%	0.0%	0.0%	0.1%	0.1%	0.2%
Total Positive Markup	30.1%	3.5%	33.6%	26.2%	4.0%	30.3%
Total	84.2%	15.8%	100.0%	78.5%	21.5%	100.0%

The markup of marginal units was zero or negative in 69.7 percent of real-time marginal unit intervals and 66.4 percent of day-ahead marginal unit intervals in the first nine months of 2021. Pivotal suppliers in the aggregate market also set prices with high markups in the first nine months of 2021. Allowing positive markups to affect prices in the presence of market power permits the exercise of market power and has a negative impact on the competitiveness of the PJM energy market. This problem can and should be addressed.