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 six 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 six months of 2021 was, on average, unconcentrated by FERC HHI standards. Average HHI was 751 with a minimum of 574 and a maximum of 1118 in the first six 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, but the implementation of fast start pricing and the extended ORDC in September 2021 and March 2022 will 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 151,999 MW for spring 2020, and 151,376 MW for spring 2021. The average on-peak hourly offered real-time supply was 123,217 MW for spring 2020, and 121,843 MW for spring 2021. In the first six months of 2021, 1,538.8 MW

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.

of new resources were added in the energy market, and 1,251.4 MW of resources were retired.

- PJM average hourly real-time cleared generation in the first six months of 2021 increased by 5.5 percent from the first six months of 2020, from 87,044 MWh to 91,798 MWh
- PJM average hourly day-ahead supply in the first six months of 2021, including INCs and UTCs, decreased by 6.7 percent from the first six months of 2020, from 109,126 MWh to 101,836 MWh.
- **Demand.** The PJM system real-time hourly peak load plus exports in the first six months of 2021 was 148,667 MWh (143,559 MW of load plus 5,108 MW of gross exports) in the HE 1700 on June 29, 2021, which was 12,767 MWh, 9.4 percent, higher than the PJM peak load plus exports in the first six months of 2020, which was 135,900 MWh in the HE 1600 on June 10, 2020.

  PJM average hourly real-time load in the first six months of 2021 increased by 5.8 percent from the first six months of 2020, from 81,255 MWh to 85,958 MWh.

  PJM average hourly day-ahead demand in the first six months of 2021, including DECs and UTCs, decreased by 6.8 percent from the first six months of 2020, from 104,164 MWh to 97,083 MWh.

Market Behavior

- **Generator Offers.** In the day-ahead market in the first six months of 2021, 19.6 percent of MW were offered as must run, 28.0 percent were the economic minimum MW for dispatchable units, 51.7 percent were offered as a dispatchable range, and 0.6 percent were offered as emergency maximum MW.
- **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 13.2 percent and cleared MW decreased by 4.9 percent in the first six months of 2021 compared to the first six months of 2020. The hourly average submitted decrement bid MW increased by 29.3 percent and cleared MW increased by 17.5 percent in the first six months of 2021 compared to the first six months of 2020. The hourly average submitted up to congestion bid MW decreased by 50.1 percent and cleared MW decreased by 59.8 percent in the first six months of 2021 compared to the first six months of 2020.

Market Performance

- **Generation Fuel Mix.** In the first six months of 2021, coal units provided 23.5 percent, nuclear units 33.0 percent and natural gas units 35.6 percent of total generation. Compared to the first six months of 2020, the generation from coal units increased 39.7 percent, from nuclear units decreased 2.2 percent and from natural gas units decreased 4.6 percent.
- **Fuel Diversity.** The fuel diversity of energy generation for the first six months of 2021, measured by the fuel diversity index for energy (FDI_e), increased 2.8 percent compared to the first six months of 2020.
- **Marginal Resources.** In the PJM Real-Time Energy Market in the first six months of 2021, coal units were 16.8 percent and natural gas units were 68.7 percent of marginal resources. In the first six months of 2020, coal units were 16.4 percent and natural gas units were 74.3 percent of marginal resources.

  In the PJM Day-Ahead Energy Market in the first six months of 2021, UTCs were 36.5 percent, INCs were 17.7 percent, DECs were 25.1 percent, and generation resources were 20.4 percent of marginal resources. In the first six months of 2020, UTCs were 52.3 percent, INCs were 14.3 percent, DECs were 14.2 percent, and generation resources were 19.2 percent of marginal resources.
- **Prices.** PJM load-weighted, average, real-time LMP in the first six months of 2021 increased 57.8 percent from the first six months of 2020, from $19.40 per MWh to $30.62 per MWh.

PJM load-weighted, average day-ahead LMP in the first six months of 2021 increased 61.2 percent from the first six months of 2020, from $19.23 per MWh to $31.00 per MWh.

- **Components of LMP.** In the PJM Real-Time Energy Market in the first six months of 2021, 14.0 percent of the load-weighted LMP was the result of coal costs, 51.7 percent was the result of gas costs and 3.2 percent was the result of the cost of emission allowances. In the first six months of 2021, 11.2 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.

  In the PJM Day-Ahead Energy Market, in the first six months of 2021, 27.7 percent of the load-weighted LMP was the result of gas costs, 28.3 percent was the result of DEC bids, 14.3 percent was the result of coal costs, 12.4 percent was the result of INC offers, 0.7 percent was the result of markup, and 2.2 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 -$0.29 per MWh in the first six months of 2021, and $0.15 per MWh in the first six 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 ten intervals with five minute shortage pricing in the first six months of 2021. There were no emergency actions that resulted in Performance Assessment Intervals in the first six months of 2021.
- There were 1,301 five minute intervals, or 2.5 percent of all five minute intervals in the first six months of 2021 for which at least one RT SCED solution showed a shortage of reserves, and 333 five minute intervals, or 0.6 percent of all five minute intervals in the first six months of 2021 for which more than one RT SCED solution showed a shortage of reserves. PJM triggered shortage pricing for ten 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 six months of 2021, 12 control zones experienced congestion resulting from one or more constraints binding for 50 or more hours. For four out of the top 10 congested facilities (by real-time binding hours) in the first six 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 increased from 1.2 percent in the first six months of 2020 to 1.3 percent in the first six 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 0.9 percent in the first six months of 2020 to 1.3 percent in the first six 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 six months of 2020 to 0.02 percent in the first six months of 2021. In the real-time energy market, for units committed for reliability reasons, offer-capped unit hours remained at 0.01 percent in the first six months of 2020 and 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 six months of 2021, 35.1 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 six months of 2021, on days when hot weather and cold weather alerts were declared, 31.8 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 six 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 -0.02 in the first six 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 six months of 2021 was more than $400 per MWh when using unadjusted cost-based offers.

  While the average markup index in the day-ahead market was 0.04 in the first six 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 six months of 2021 was more than $120 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 six months of 2021, the unadjusted markup component of LMP was -$0.13 per MWh or -0.4 percent of the PJM load-weighted, average LMP. June had the highest peak markup component, $2.76 per MWh, or 6.9 percent of the real-time, peak hour load-weighted, average LMP for June.

  In the PJM Day-Ahead Energy Market, INCs, DECs and UTCs have zero markups. In the first six months of 2021, the markup component of LMP was $0.22 per MWh or 0.7 percent of the PJM day-ahead load-weighted, average LMP. February had the highest unadjusted peak markup component, $2.13 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 3.8 percent of all real-time marginal unit intervals in the first six 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 six 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 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 constant 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, in order to ensure effective market power mitigation when the TPS test is failed, and during high load conditions such as cold and hot weather alerts or more severe emergencies, that the operating parameters in the cost-based offer and the price-based parameter limited schedule (PLS) offer be at least as flexible as the operating parameters in the available price-based non-PLS offer, and that

the price-MW pairs in the price-based PLS offer be exactly equal to the price-based non-PLS offer. (Priority: High. First reported 2015. Status: Not adopted.)

- The MMU recommends, in order to ensure effective market power mitigation, that PJM always enforce parameter limited values by committing units only on parameter limited schedules, when the TPS test is failed or during high load conditions such as cold and hot weather alerts or more severe emergencies. (Priority: High. First reported 2019. 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 PJM institute rules that would not pay a share of capacity market revenue to resources that choose to submit real-time values that are less flexible than their unit specific parameter limits or approved parameter limit exceptions based on tariff defined reasons. (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: Not adopted.)
- 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: Partially adopted.)
- The MMU recommends that PJM update the outage impact studies, the reliability analyses used in RPM for capacity deliverability, and the reliability analyses used in RTEP for transmission upgrades to be consistent with the more conservative emergency operations (post contingency load dump limit exceedance analysis) in the energy market that were implemented in June 2013. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that 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.)
- 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.)

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 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. New recommendation. 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 six 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 six months of 2021 increased by 5.8 percent from the first six months of 2020, from 81,255 MWh to 85,958 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. Many of these issues can be resolved by simple rule changes.

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 six months of 2021 generally reflected supply-demand fundamentals, although the behavior of some participants both routinely and during high 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 not too low. Prices in PJM are the result of input prices, consistent with a competitive market. Low natural gas prices have been a

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

primary cause of low PJM energy market prices. There is no evidence to support the need for a significant change to the calculation of LMP, such as fast start pricing or the extended ORDC. Fast start pricing and the extended ORDC will disconnect pricing from dispatch instructions and create greater reliance on uplift as an incentive to follow PJM's instructions. The extended ORDCs will create shortage pricing when no reserve shortages exist. Rather than undercutting the basic LMP logic that is core to market efficiency, it would make more sense to directly address the design of RT SCED/LPC, scarcity pricing, operator actions and the design of reserve markets. PJM has made progress in addressing the timing of RT SCED and LPC and accepting shortage pricing in some cases when SCED shows a shortage, but more progress is needed.

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 through transmission line limit violations or restrictions on the resources available to resolve constraints. The automated adjustment of ramp rates by PJM, called Degree of Generator Performance (DGP), modifies the values offered by generators and limits the MW available to the RT SCED. 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 will be created by PJM's fast start pricing proposal as approved by FERC and would be created in a much more extensive form by PJM's pending extended ORDC pricing changes.[8]

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 will pay 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 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 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.

8 See 173 FERC ¶ 61,244 (2020).

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 six months of 2021 or prior years. In the first six 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 31.5 percent in the first six months of 2016 to 61.1 percent in the first six 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 six months of 2021.

Supply and Demand

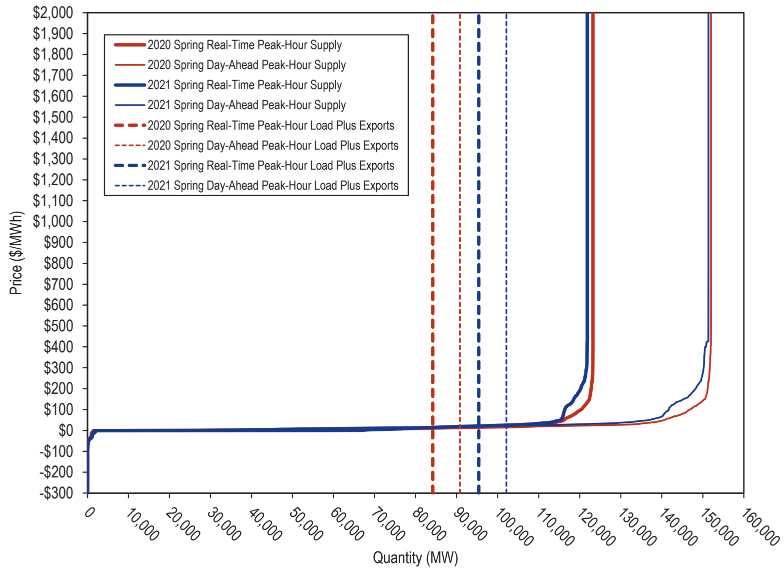
Market Structure

Supply

Supply includes physical generation, imports and virtual transactions.

In the first six months of 2021, 1,538.8 MW of new resources were added in the energy market, and 1,251.4 MW of resources were retired. Figure 3-1 shows the average real-time and day-ahead supply curves in spring 2020 and 2021.[9] [10] 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: Spring of 2020 and 2021



9 Real-time supply includes real-time generation offers and import MWh.
10 The supply curve period is from March 1 to May 31

Figure 3-2 shows the typical dispatch range.

Figure 3-2 Typical dispatch range of supply curves

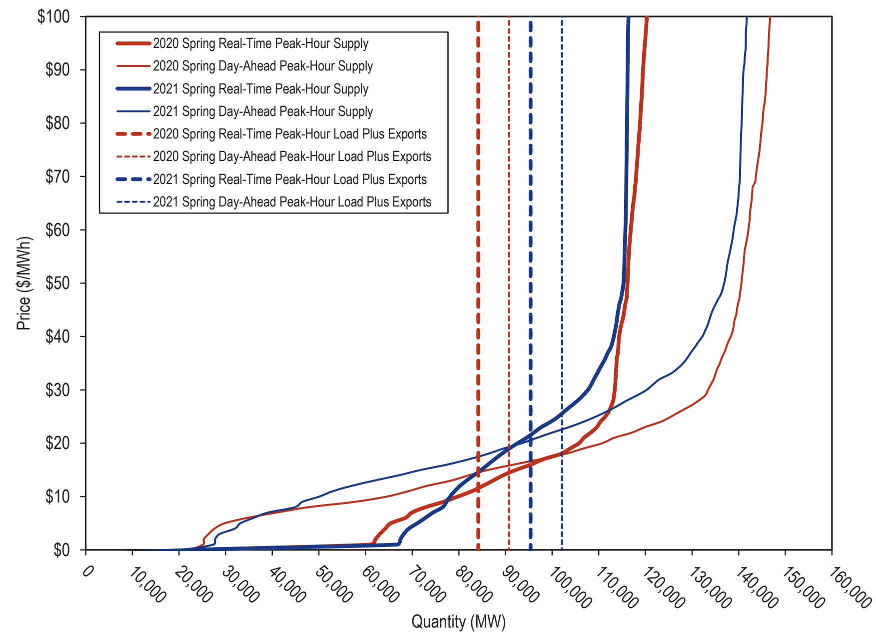


Table 3-2 shows the price elasticity of the real-time supply curve for the on peak hours in the spring of 2019 to 2021 by load level.

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.

Table 3-2 Price elasticity of the supply curve

Elasticity of Spring Supply Curve			
GW	2019	2020	2021
Min - 75	0.015	0.032	0.021
75 - 95	0.200	0.317	0.148
95 - 115	0.271	0.105	0.111
115 - Max	0.003	0.003	0.004

Real-Time Supply

PJM average hourly real-time cleared generation in the first six months of 2021 increased by 5.5 percent from the first six months of 2020, from 87,044 MWh to 91,798 MWh.[11]

PJM average hourly real-time cleared supply including imports in the first six months of 2021 increased by 5.5 percent from the first six months of 2020, from 87,861 MWh to 92,655 MWh.

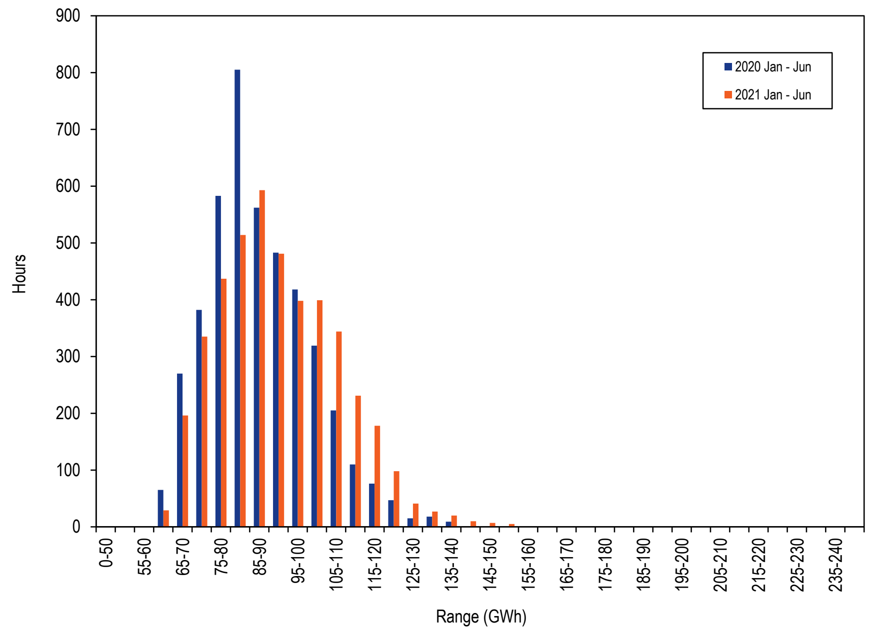
In the PJM Real-Time Energy Market, there are three types of supply offers:

- **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 six months of 2020 and 2021.

Figure 3-3 Distribution of real-time generation plus imports: January through June, 2020 and 2021[12]



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

12 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 six months of each year from 2001 through 2021.

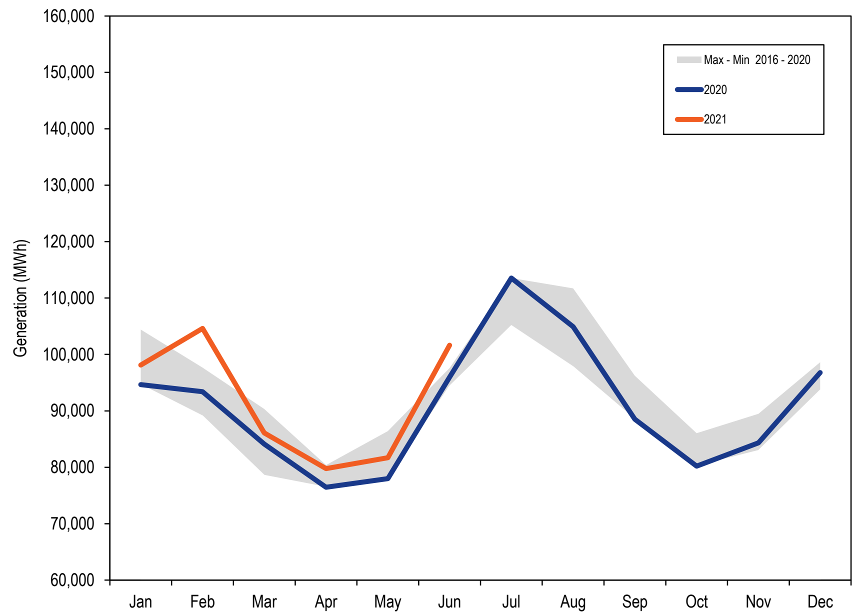
Table 3-3 Average hourly real-time generation and real-time generation plus imports: January through June, 2001 through 2021

	PJM Real-Time Supply (MWh)				Year-to-Year Change			
	Generation		Generation Plus Imports		Generation		Generation Plus Imports	
Jan-Jun	Generation	Standard Deviation	Supply	Standard Deviation	Generation	Standard Deviation	Supply	Standard Deviation
2001	29,428	4,679	32,412	4,813	NA	NA	NA	NA
2002	30,967	5,770	34,730	6,238	5.2%	23.3%	7.2%	29.6%
2003	36,034	6,008	39,644	6,021	16.4%	4.1%	14.1%	(3.5%)
2004	41,430	9,435	45,597	9,699	15.0%	57.0%	15.0%	61.1%
2005	74,365	12,661	79,693	13,242	79.5%	34.2%	74.8%	36.5%
2006	80,249	11,011	84,819	11,574	7.9%	(13.0%)	6.4%	(12.6%)
2007	83,478	12,105	88,150	13,192	4.0%	9.9%	3.9%	14.0%
2008	83,294	12,458	88,824	12,778	(0.2%)	2.9%	0.8%	(3.1%)
2009	77,508	12,961	82,928	13,580	(6.9%)	4.0%	(6.6%)	6.3%
2010	80,702	13,968	85,575	14,455	4.1%	7.8%	3.2%	6.4%
2011	81,483	13,677	86,268	14,428	1.0%	(2.1%)	0.8%	(0.2%)
2012	86,310	13,695	91,526	14,279	5.9%	0.1%	6.1%	(1.0%)
2013	87,974	13,528	93,166	14,277	1.9%	(1.2%)	1.8%	(0.0%)
2014	92,458	15,722	98,186	16,710	5.1%	16.2%	5.4%	17.0%
2015	90,097	16,028	96,626	17,168	(2.6%)	1.9%	(1.6%)	2.7%
2016	86,335	14,576	91,218	15,231	(4.2%)	(9.1%)	(5.6%)	(11.3%)
2017	88,669	13,528	91,108	14,029	2.7%	(7.2%)	(0.1%)	(7.9%)
2018	91,631	14,828	94,091	15,312	3.3%	9.6%	3.3%	9.1%
2019	91,613	14,403	92,947	14,735	(0.0%)	(2.9%)	(1.2%)	(3.8%)
2020	87,044	13,308	87,861	13,453	(5.0%)	(7.6%)	(5.5%)	(8.7%)
2021	91,798	15,382	92,655	15,620	5.5%	15.6%	5.5%	16.1%

PJM Real-Time, Monthly Average Generation

Figure 3-4 compares the real-time, monthly average hourly generation in 2020 and the first six 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 June 2021



Day-Ahead Supply

PJM average hourly day-ahead cleared supply in the first six months of 2021, including INCs and up to congestion transactions, decreased by 6.7 percent from the first six months of 2020, from 109,126 MWh to 101,836 MWh. When imports are added, PJM average hourly, day-ahead cleared supply in the first six months of 2021 decreased by 6.7 percent from the first six months of 2020, from 109,369 MWh to 102,057 MWh. The decrease of day-ahead supply was a result of a decrease in UTCs.

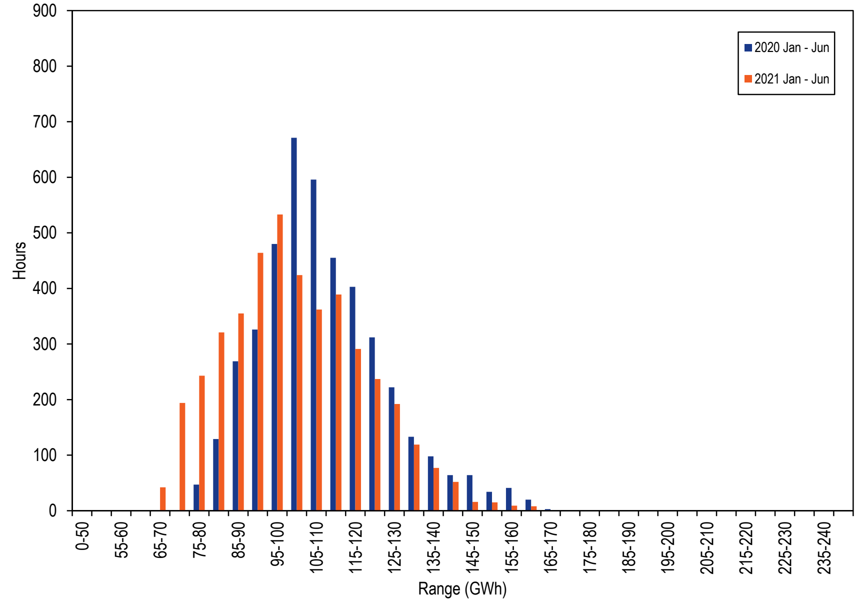
In the PJM Day-Ahead Energy Market, there are five types of financially binding supply offers:

- **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 six months of 2020 and 2021.

Figure 3-5 Distribution of day-ahead cleared supply plus imports: January through June, 2020 and 2021[13]



13 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 six months of each year from 2001 through 2021.

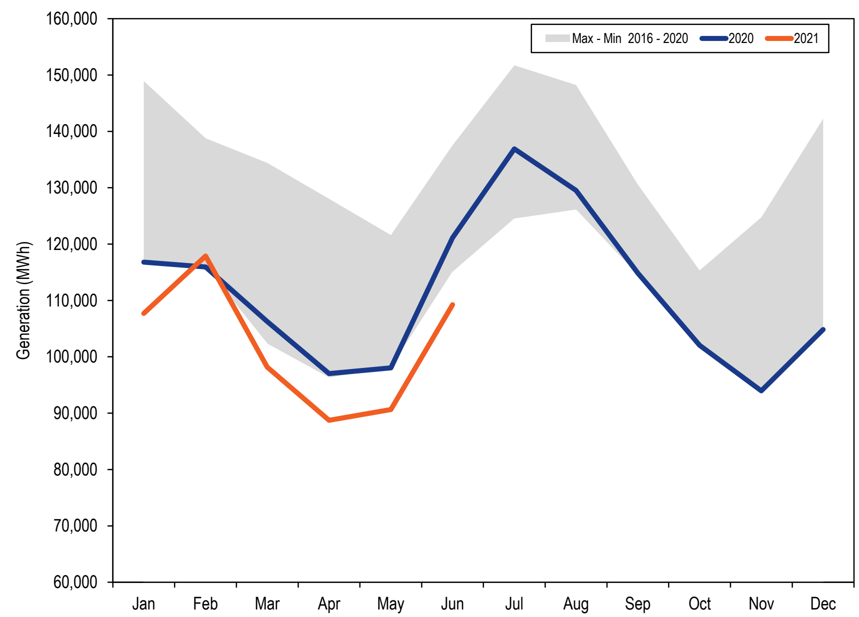
Table 3-4 Average hourly day-ahead cleared supply and day-ahead cleared supply plus imports: January through June, 2001 through 2021

	PJM Day-Ahead Supply (MWh)				Year-to-Year Change			
	Supply		Supply Plus Imports		Supply		Supply Plus Imports	
Jan-Jun	Supply	Standard Deviation	Supply	Standard Deviation	Supply	Standard Deviation	Supply	Standard Deviation
2001	26,796	4,305	27,540	4,382	NA	NA	NA	NA
2002	25,840	10,011	26,398	10,021	(3.6%)	132.5%	(4.1%)	128.7%
2003	36,420	7,000	36,994	7,023	40.9%	(30.1%)	40.1%	(29.9%)
2004	50,089	10,108	50,836	10,171	37.5%	44.4%	37.4%	44.8%
2005	87,855	14,365	89,382	14,395	75.4%	42.1%	75.8%	41.5%
2006	95,562	12,620	97,796	12,615	8.8%	(12.1%)	9.4%	(12.4%)
2007	106,470	14,522	108,815	14,772	11.4%	15.1%	11.3%	17.1%
2008	104,705	14,124	107,169	14,190	(1.7%)	(2.7%)	(1.5%)	(3.9%)
2009	97,607	16,283	100,076	16,342	(6.8%)	15.3%	(6.6%)	15.2%
2010	102,626	18,206	105,463	18,378	5.1%	11.8%	5.4%	12.5%
2011	108,143	16,666	110,656	16,926	5.4%	(8.5%)	4.9%	(7.9%)
2012	132,326	15,710	134,747	15,841	22.4%	(5.7%)	21.8%	(6.4%)
2013	148,381	15,606	150,554	15,830	12.1%	(0.7%)	11.7%	(0.1%)
2014	165,620	13,930	167,939	14,119	11.6%	(10.7%)	11.5%	(10.8%)
2015	115,150	18,851	117,613	18,996	(30.5%)	35.3%	(30.0%)	34.5%
2016	127,715	20,380	129,798	20,518	10.9%	8.1%	10.4%	8.0%
2017	133,601	19,109	134,433	19,293	4.6%	(6.2%)	3.6%	(6.0%)
2018	113,028	21,246	113,493	21,258	(15.4%)	11.2%	(15.6%)	10.2%
2019	115,511	16,792	115,896	16,811	2.2%	(21.0%)	2.1%	(20.9%)
2020	109,126	16,253	109,369	16,248	(5.5%)	(3.2%)	(5.6%)	(3.3%)
2021	101,836	17,741	102,057	17,778	(6.7%)	9.2%	(6.7%)	9.4%

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 six 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 June 2021



Real-Time and Day-Ahead Supply

Table 3-5 presents summary statistics for the first six 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 June, 2020 and 2021

		Day-Ahead					Real-Time		Day-Ahead Less Real-Time	
	Jan-Jun	Generation	INC Offers	Up to Congestion	Imports	Total Supply	Generation	Total Supply	Generation	Supply
Average	2020	87,013	2,562	19,551	243	109,369	87,044	87,861	(31)	21,508
	2021	91,558	2,423	7,855	221	102,057	91,798	92,655	(240)	9,402
Median	2020	84,934	2,513	19,408	225	107,105	84,894	85,598	40	21,507
	2021	89,785	2,320	7,663	150	100,194	89,987	90,713	(202)	9,481
Standard Deviation	2020	14,237	762	3,687	167	16,248	13,308	13,453	929	2,795
	2021	15,954	1,000	2,835	265	17,778	15,382	15,620	571	2,158
Peak Average	2020	94,576	2,818	20,509	217	118,121	93,707	94,552	869	23,568
	2021	98,960	2,895	8,918	199	110,972	98,780	99,718	180	11,255
Peak Median	2020	93,025	2,787	20,287	200	115,771	92,211	93,125	814	22,646
	2021	97,444	2,893	8,668	136	109,026	97,139	97,762	305	11,264
Peak Standard Deviation	2020	12,879	771	3,786	160	15,074	12,323	12,497	556	2,577
	2021	14,160	994	2,613	235	15,214	13,965	14,213	195	1,001
Off-Peak Average	2020	80,335	2,336	18,705	265	101,640	81,160	81,951	(825)	19,689
	2021	85,050	2,007	6,920	241	94,218	85,658	86,445	(609)	7,773
Off-Peak Median	2020	78,680	2,274	18,521	245	100,599	79,813	80,667	(1,132)	19,932
	2021	82,851	1,906	6,632	165	91,433	83,596	84,107	(745)	7,327
Off-Peak Standard Deviation	2020	11,838	677	3,379	169	13,006	11,207	11,335	631	1,671
	2021	14,544	800	2,691	288	16,100	13,880	14,090	664	2,010

Figure 3-7 shows the average cleared volumes of day-ahead supply and real-time supply by hour of the day for the first six 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 June, 2021

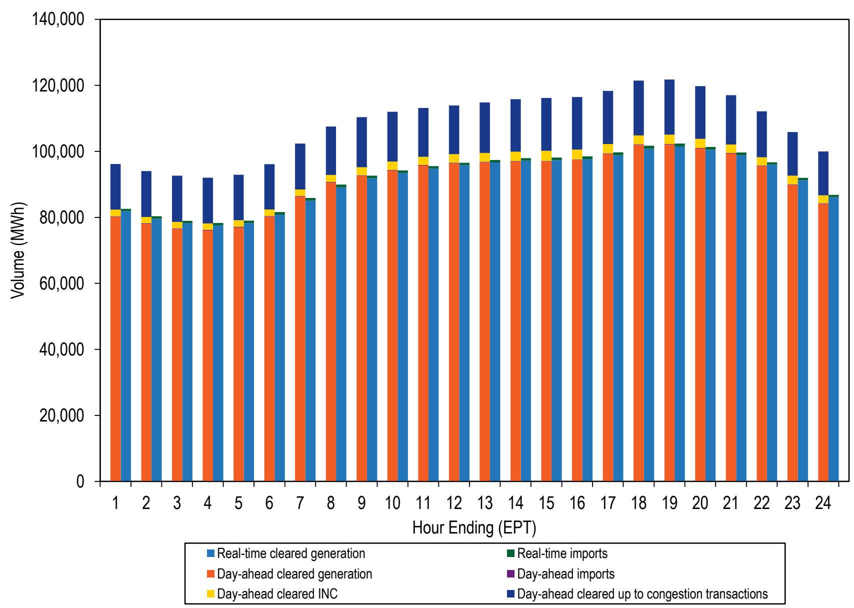
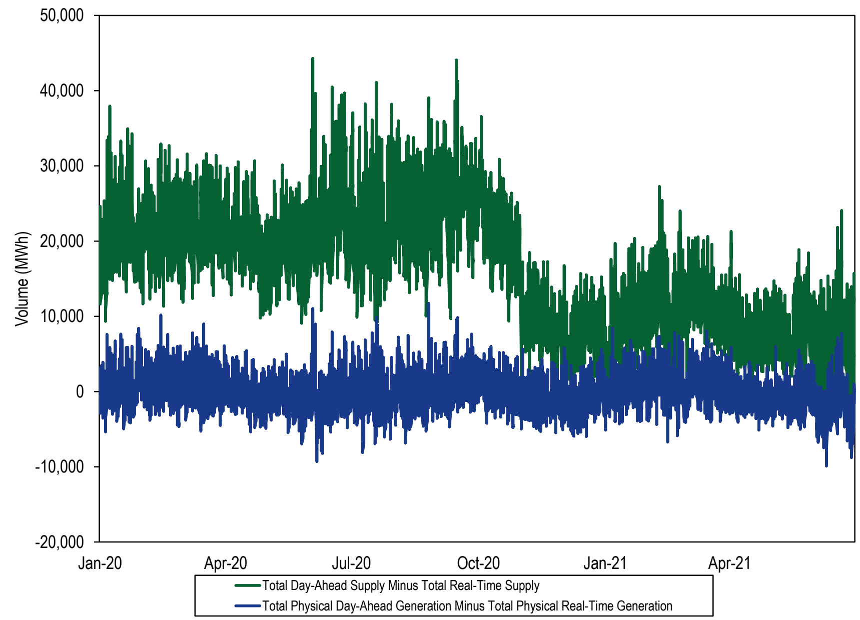


Figure 3-8 shows the difference between the day-ahead and real-time average daily supply in 2020 and the first six months of 2021.

Figure 3-8 Difference between cleared day-ahead and real-time supply (Average daily volumes): January 2020 through June 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.[14]

The PJM system real-time hourly peak load plus exports in the first six months of 2021 was 148,667 MWh in the HE 1700 on June 29, 2021, which was 12,767 MWh, 9.4 percent, higher than the PJM peak load plus exports in the first six months of 2020, which was 135,900 MWh in the HE 1600 on June 10, 2020.

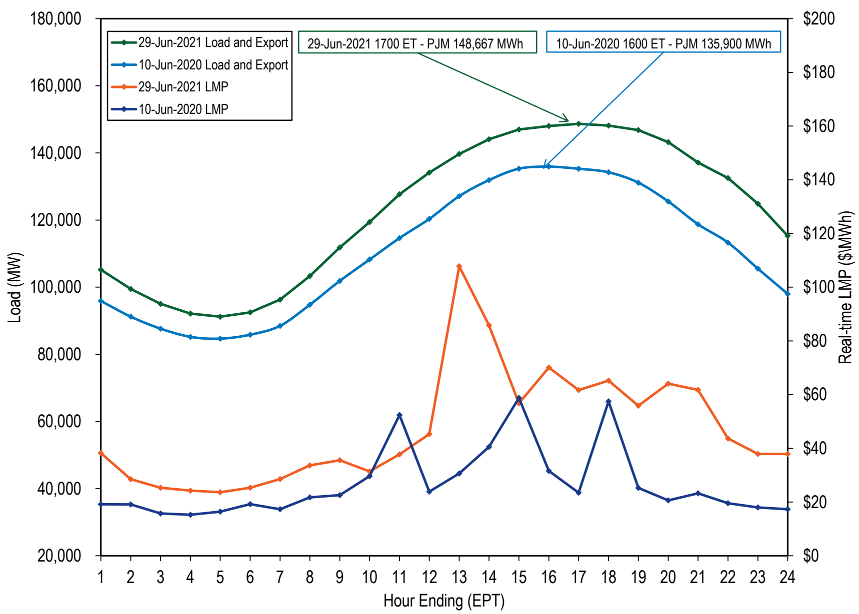
Table 3-6 shows the peak loads plus export for the first six months of 2009 through 2021.

Table 3-6 Actual footprint peak loads plus export: January through June, 2009 through 2021[15 16]

(Jan - Jun)	Date	Hour Ending (EPT)	PJM Load Plus Export (MWh)	Annual Change (MWh)	Annual Change (%)
2009	Fri, January 16	9	128,310	NA	NA
2010	Wed, June 23	17	136,847	8,538	6.7%
2011	Wed, June 08	18	153,559	16,712	12.2%
2012	Fri, June 29	17	156,664	3,105	2.0%
2013	Tue, June 25	16	140,221	(16,443)	(10.5%)
2014	Tue, June 17	18	142,428	2,206	1.6%
2015	Fri, February 20	8	144,850	2,422	1.7%
2016	Mon, June 20	18	137,162	(7,688)	(5.3%)
2017	Mon, June 12	18	142,633	5,471	4.0%
2018	Mon, June 18	17	150,234	7,601	5.3%
2019	Wed, January 30	20	140,037	(10,197)	(6.8%)
2020	Wed, June 10	16	135,900	(4,137)	(3.0%)
2021	Tue, June 29	17	148,667	12,767	9.4%

Figure 3-9 compares prices and demand on the peak load days in the first six months of 2020 and 2021. The average, real-time LMP for June 10, 2021, peak load hour was $31.56 and for June 29, 2021 peak load hour it was $61.71.

Figure 3-9 Peak load and export day comparison: Wednesday, June 10, 2020 and Tuesday, June 29, 2021



14 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.

15 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>.

16 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 average hourly real-time load in the first six months of 2021 increased by 5.8 percent from the first six months of 2020, from 81,255 MWh to 85,958 MWh.[17] PJM average hourly real-time demand including exports in the first six months of 2021 increased by 5.3 percent from the first six months of 2020, from 86,344 MWh to 90,960 MWh.

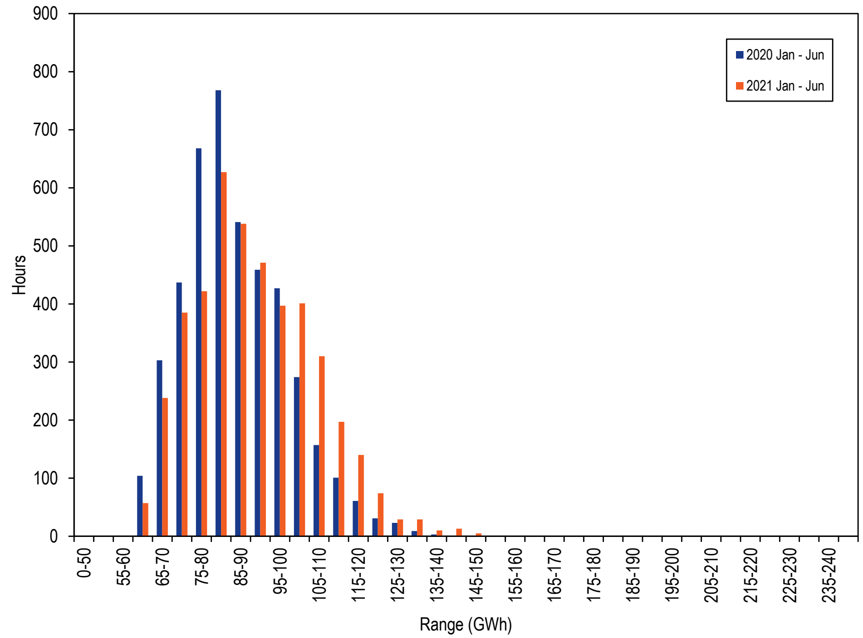
In the PJM Real-Time Energy Market, there are two types of demand:

- **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 hourly PJM real-time load plus exports in the first six months of 2020 and 2021.[18]

Figure 3-10 Distribution of real-time accounting load plus exports: January through June, 2020 and 2021[19]



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

18 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>.

19 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 six months of each year from 2001 through 2021.[20]

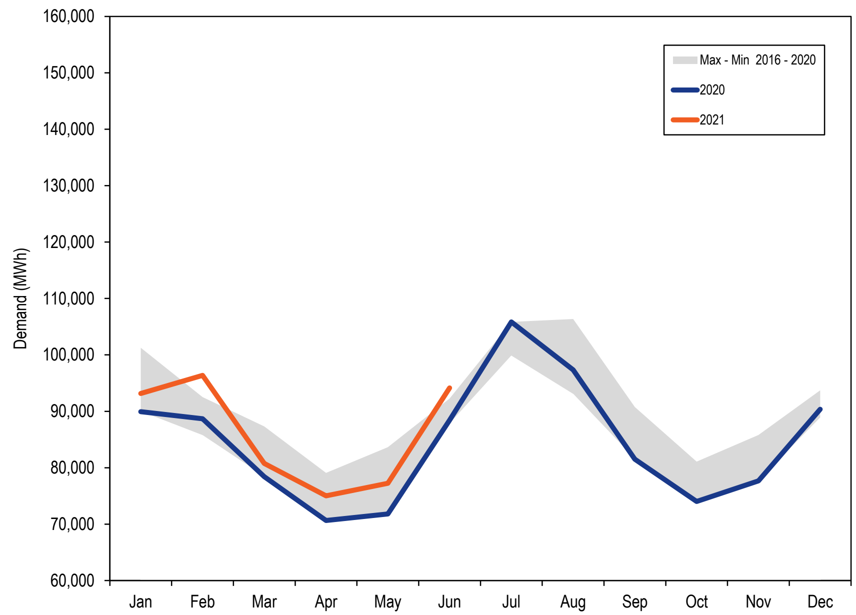
Table 3-7 Real-time average hourly load and load plus exports: January through June, 2001 through 2021

	PJM Real-Time Demand (MWh)				Year to Year Change			
	Load		Load Plus Exports		Load		Load Plus Exports	
Jan-Jun	Load	Standard Deviation	Demand	Standard Deviation	Load	Standard Deviation	Demand	Standard Deviation
2001	30,180	5,274	32,041	5,103	NA	NA	NA	NA
2002	32,678	6,457	33,969	6,557	8.3%	22.4%	6.0%	28.5%
2003	36,727	6,428	38,775	6,554	12.4%	(0.4%)	14.1%	(0.0%)
2004	41,787	8,999	44,808	10,033	13.8%	40.0%	15.6%	53.1%
2005	71,939	13,603	78,745	13,798	72.2%	51.2%	75.7%	37.5%
2006	77,232	12,003	83,606	12,377	7.4%	(11.8%)	6.2%	(10.3%)
2007	81,110	13,499	86,557	13,819	5.0%	12.5%	3.5%	11.6%
2008	78,685	12,819	85,819	13,242	(3.0%)	(5.0%)	(0.9%)	(4.2%)
2009	75,991	12,899	81,062	13,253	(3.4%)	0.6%	(5.5%)	0.1%
2010	78,106	13,643	83,758	14,227	2.8%	5.8%	3.3%	7.3%
2011	78,823	13,931	84,288	14,046	0.9%	2.1%	0.6%	(1.3%)
2012	84,946	13,941	89,638	13,848	7.8%	0.1%	6.3%	(1.4%)
2013	86,897	13,871	91,199	13,848	2.3%	(0.5%)	1.7%	0.0%
2014	90,529	16,266	96,189	16,147	4.2%	17.3%	5.5%	16.6%
2015	90,586	16,192	94,782	16,589	0.1%	(0.5%)	(1.5%)	2.7%
2016	85,800	14,517	89,746	14,798	(5.3%)	(10.3%)	(5.3%)	(10.8%)
2017	84,569	13,670	89,477	13,638	(1.4%)	(5.8%)	(0.3%)	(7.8%)
2018	88,847	14,683	92,352	14,818	5.1%	7.4%	3.2%	8.7%
2019	86,297	14,038	91,262	14,303	(2.9%)	(4.4%)	(1.2%)	(3.5%)
2020	81,255	13,191	86,344	13,133	(5.8%)	(6.0%)	(5.4%)	(8.2%)
2021	85,958	14,269	90,960	15,221	5.8%	8.2%	5.3%	15.9%

PJM Real-Time, Monthly Average Load

Figure 3-11 compares the real-time, monthly average load plus exports in 2020 and the first six 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.

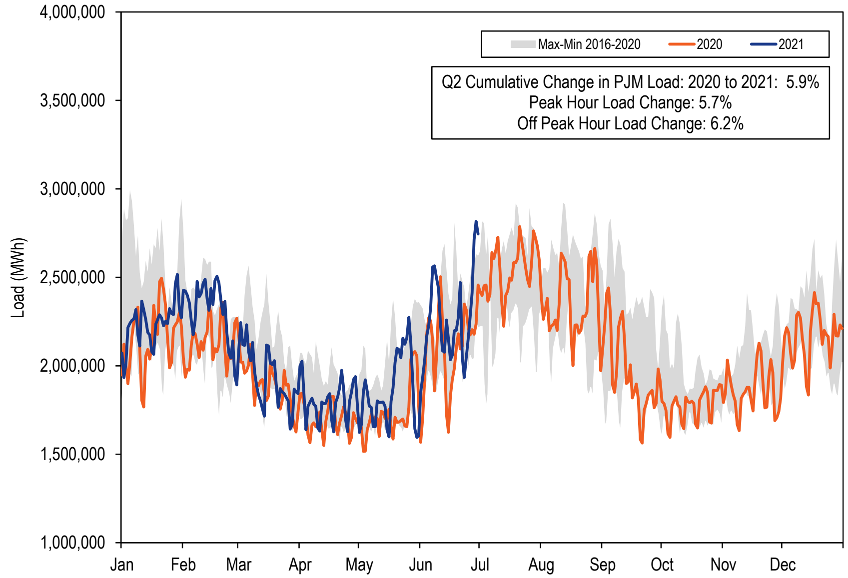
Figure 3-11 Real-time monthly average hourly load plus exports: January 2020 through June 2021



20 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 six months of 2021, with the historic five year range.

Figure 3-12 Real-time daily load: January 2020 through June 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 six months of 2021.[21] Heating degree days increased 9.7 percent, and cooling degree days increased 16.1 percent compared to the first six months of 2020.

Table 3-8 Heating and cooling degree days: January 2020 through June 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				
Aug	0	342				
Sep	13	120				
Oct	139	1				
Nov	313	0				
Dec	719	0				
Jan-Jun	2,118	321	2,323	373	9.7%	16.1%

Figure 3-13 shows the real-time daily load and the weather normalized load for 2020 through the first six months of 2021.

Weather normalized load is calculated using the historic relationship between PJM daily load and HDD, CDD, and time of year for 2015 through 2018. Figure 3-13 shows that from March through May 2020, the actual load was significantly less than the weather normalized load. The difference was a result of changes in the pattern and level of activity due to COVID-19 and associated policy responses.

21 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.

Figure 3-13 Real-time daily load and weather normalized load: January 2020 through June 2021

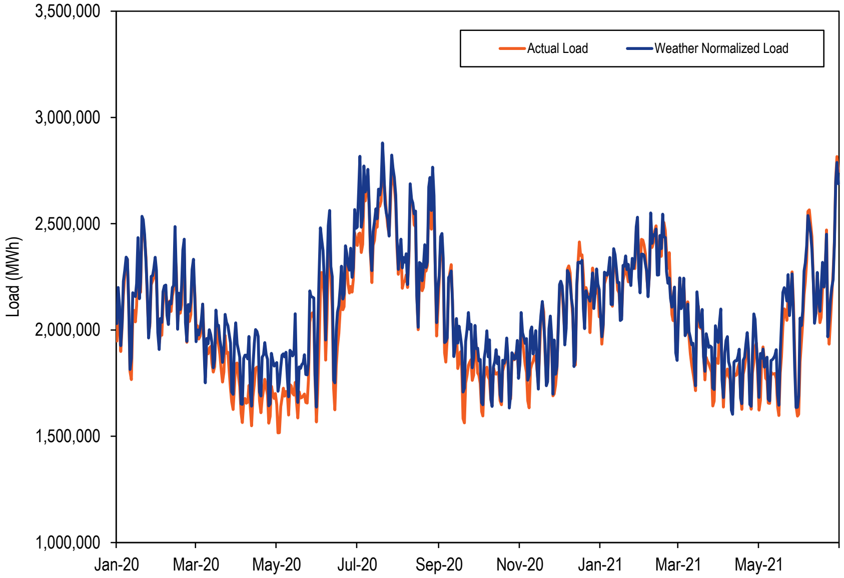


Table 3-9 compares the total monthly actual load and weather normalized load. The gap between actual load and weather normalized load in the first six months of 2021 is significantly smaller than in the first six months of 2020.

Table 3-9 Actual load and weather normalized load: January 2020 through June 2021

	2020			2021		
	Actual Load	Weather Normalized Load	Percent Difference	Actual Load	Weather Normalized Load	Percent Difference
Jan	66,905,774	68,256,113	(2.0%)	69,303,496	69,689,108	(0.6%)
Feb	61,717,353	62,471,212	(1.2%)	64,761,103	64,275,946	0.8%
Mar	58,258,178	60,459,812	(3.6%)	60,002,018	61,459,726	(2.4%)
Apr	50,864,950	55,116,626	(7.7%)	54,010,529	55,580,210	(2.8%)
May	53,430,088	57,904,128	(7.7%)	57,460,157	59,183,412	(2.9%)
Jun	63,666,037	67,406,845	(5.5%)	67,779,457	68,488,450	(1.0%)
Jul	78,749,183	80,856,404	(2.6%)			
Aug	72,425,029	74,173,773	(2.4%)			
Sep	58,683,018	60,988,913	(3.8%)			
Oct	55,061,813	56,572,150	(2.7%)			
Nov	55,993,432	57,678,640	(2.9%)			
Dec	67,232,280	67,074,317	0.2%			
Jan - Jun	354,842,381	371,614,736	(4.5%)	373,316,760	378,676,852	(1.4%)

Day-Ahead Demand

PJM average hourly day-ahead demand in the first six months of 2021, including DECs and UTCs, decreased by 6.8 percent from the first six months of 2020, from 104,164 MWh to 97,083 MWh. When exports are added, PJM average hourly day-ahead demand in the first six months of 2021 decreased by 6.7 percent from the first six months of 2020, from 107,293 MWh to 100,060 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.

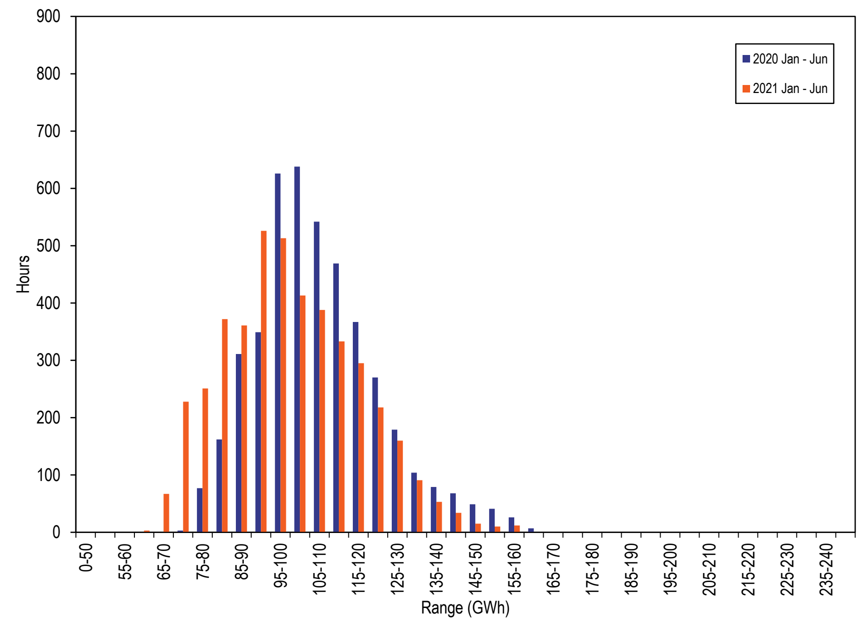
- **Decrement Bid (DEC).** Financial bid to purchase a defined MWh level of energy up to a specified LMP, above which the bid is zero.
- **Up to Congestion Transaction (UTC).** A conditional transaction that permits a market participant to specify a maximum price spread between the transaction source 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 3-14 shows the hourly distribution of PJM day-ahead demand for the first six months of 2020 and 2021.

Figure 3-14 Distribution of day-ahead demand plus exports: January through June, 2020 and 2021[22]



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

PJM Day-Ahead, Average Demand

Table 3-10 shows day-ahead hourly demand for the first six months of 2001 through 2021. The monthly average hourly demand in first six months of 2021, with and without exports, is lower than any year since 2010, as a result of the reduction in UTC transaction volumes.

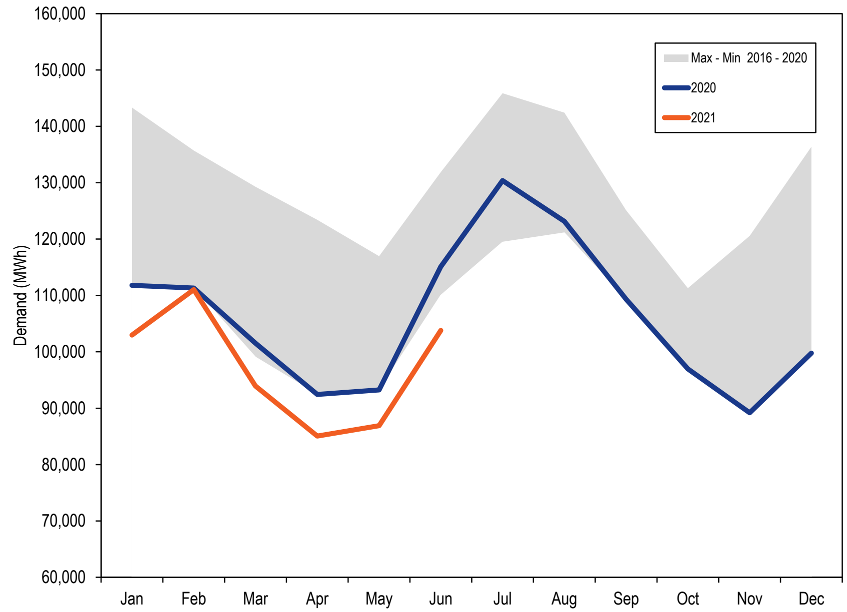
Table 3-10 Average hourly day-ahead demand and day-ahead demand plus exports: January through June, 2001 through 2021

	PJM Day-Ahead Demand (MWh)				Year to Year Change			
	Demand		Demand Plus Exports		Demand		Demand Plus Exports	
Jan-Jun	Demand	Standard Deviation	Demand	Standard Deviation	Demand	Standard Deviation	Demand	Standard Deviation
2001	32,425	6,014	33,075	5,857	NA	NA	NA	NA
2002	37,561	8,293	37,607	8,311	15.8%	37.9%	13.7%	41.9%
2003	44,391	7,717	44,503	7,704	18.2%	(6.9%)	18.3%	(7.3%)
2004	50,161	10,304	50,596	10,557	13.0%	33.5%	13.7%	37.0%
2005	86,890	14,677	89,388	14,827	73.2%	42.4%	76.7%	40.4%
2006	94,470	12,925	97,460	13,303	8.7%	(11.9%)	9.0%	(10.3%)
2007	104,737	15,019	107,647	15,269	10.9%	16.2%	10.5%	14.8%
2008	100,948	14,255	104,499	14,461	(3.6%)	(5.1%)	(2.9%)	(5.3%)
2009	95,130	15,878	98,001	15,972	(5.8%)	11.4%	(6.2%)	10.4%
2010	99,691	18,097	103,573	18,366	4.8%	14.0%	5.7%	15.0%
2011	105,071	16,452	108,756	16,578	5.4%	(9.1%)	5.0%	(9.7%)
2012	129,881	15,268	133,046	15,436	23.6%	(7.2%)	22.3%	(6.9%)
2013	145,280	15,552	148,414	15,588	11.9%	1.9%	11.6%	1.0%
2014	160,805	13,872	164,740	13,800	10.7%	(10.8%)	11.0%	(11.5%)
2015	111,750	18,076	115,117	18,477	(30.5%)	30.3%	(30.1%)	33.9%
2016	124,542	19,750	127,461	19,991	11.4%	9.3%	10.7%	8.2%
2017	128,690	18,440	131,976	18,746	3.3%	(6.6%)	3.5%	(6.2%)
2018	108,950	20,548	111,451	20,718	(15.3%)	11.4%	(15.6%)	10.5%
2019	110,890	15,994	113,738	16,323	1.8%	(22.2%)	2.1%	(21.2%)
2020	104,164	15,680	107,293	15,845	(6.1%)	(2.0%)	(5.7%)	(2.9%)
2021	97,083	16,637	100,060	17,277	(6.8%)	6.1%	(6.7%)	9.0%

PJM Day-Ahead, Monthly Average Demand

Figure 3-15 compares the day-ahead, monthly average hourly demand, including decrement bids and up to congestion transactions in 2020 and first six months of 2021 with the historic five-year range.

Figure 3-15 Day-ahead monthly average hourly demand plus exports: January 2020 through June 2021



Real-Time and Day-Ahead Demand

Table 3-11 presents summary statistics for the first six months of 2020 and 2021 day-ahead and real-time demand. The last two columns of Table 3-11 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 3-11 Cleared day-ahead and real-time demand (MWh): January through June, 2020 and 2021

		Day-Ahead						Real-Time		Day-Ahead Less Real-Time	
Jan-Jun	Year	Fixed Demand	Price Sensitive	DEC Bids	Up-to Congestion	Exports	Total Demand	Load	Total Demand	Load	Demand
Average	2020	79,908	1,099	3,606	19,551	3,129	107,293	81,255	86,344	(248)	20,950
	2021	83,617	1,393	4,218	7,855	2,977	100,060	85,958	90,960	(948)	9,100
Median	2020	78,276	1,112	3,186	19,408	3,121	105,117	79,059	84,151	329	20,967
	2021	82,387	1,408	3,758	7,663	2,661	98,249	84,601	89,037	(806)	9,212
Standard Deviation	2020	12,832	226	1,864	3,687	687	15,845	13,191	13,133	(133)	2,712
	2021	13,492	250	1,878	2,835	1,123	17,277	14,269	15,221	(527)	2,056
Peak Average	2020	86,653	1,199	4,277	20,509	3,225	115,864	87,790	92,884	62	22,980
	2021	90,361	1,537	4,774	8,918	3,192	108,782	92,597	97,893	(699)	10,889
Peak Median	2020	86,061	1,233	3,878	20,287	3,200	113,650	86,855	91,479	438	22,172
	2021	89,582	1,560	4,406	8,668	2,828	106,857	91,304	96,030	(162)	10,827
Peak Standard Deviation	2020	11,337	247	2,038	3,786	682	14,672	12,120	12,195	(536)	2,477
	2021	11,522	222	1,879	2,613	1,228	14,753	12,773	13,823	(1,029)	930
Off-Peak Average	2020	73,950	1,011	3,014	18,705	3,044	99,724	75,484	80,567	(523)	19,157
	2021	77,688	1,267	3,729	6,920	2,787	92,391	80,121	84,864	(1,167)	7,527
Off-Peak Median	2020	72,546	1,027	2,721	18,521	3,044	98,774	74,111	79,275	(538)	19,500
	2021	75,540	1,291	3,317	6,632	2,565	89,728	78,191	82,624	(1,360)	7,104
Off-Peak Standard Deviation	2020	10,997	161	1,458	3,379	681	12,672	11,268	11,061	(111)	1,610
	2021	12,258	200	1,737	2,691	984	15,619	12,901	13,712	(442)	1,906

Figure 3-16 shows the average hourly cleared volumes of day-ahead demand and real-time demand for the first six 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 3-16 Day-ahead and real-time demand (Average hourly volumes): January through June, 2021

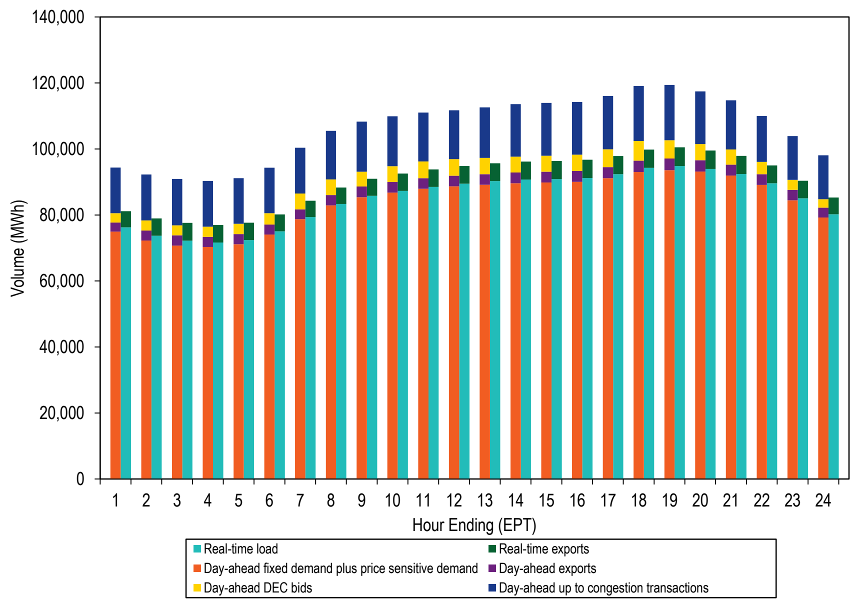
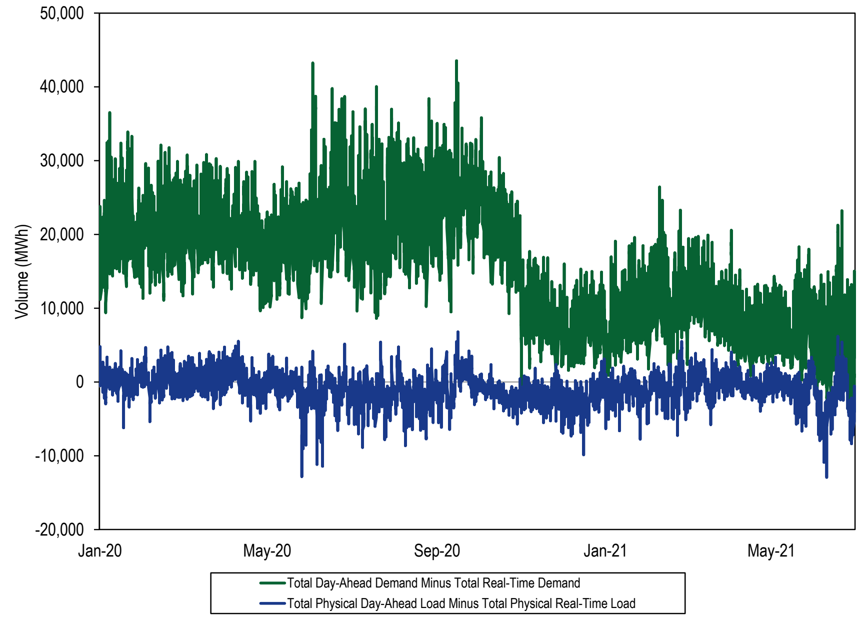


Figure 3-17 shows the difference between the day-ahead and real-time average daily demand for 2020 and the first six months of 2021.

Figure 3-17 Difference between day-ahead and real-time demand (Average daily volumes): January 2020 through June 2021



Market Behavior

Generator Offers

Generators indicate the commitment status and the dispatch status of their units in the day-ahead through their offers. For example, units that select must run status in the offer will run the unit in the day-ahead market regardless of market signals. Units may commit at economic minimum and permit the balance to be dispatchable or block load the full output of the unit. If units do not select must run status, the day-ahead market will commit and dispatch them based on their offers.

The Must Run column in Table 3-12 is the economic minimum MW of units offering with must run commitment status. The Eco Min column in Table 3-12 is the economic minimum MW of units offering with economic commitment status. The dispatchable range of Table 3-12 shows the percent of MW offered by price range, between the economic minimum MW and economic maximum MW. Units can designate all or a portion of their capacity as emergency MW. Table 3-12 shows that 0.6 percent of offered MW are emergency MW. In some cases, higher shares of emergency MW is a result of offer behavior and does not necessarily represent the actual availability of the emergency MW in real time. Some units, like wind and solar, offer a dispatchable range in the day-ahead market although their availability in real time is determined by the presence of sun and wind and are therefore generally not capable of following dispatch across the entire range in real-time.

In the day-ahead market in the first six months of 2021, 19.6 percent of MW were offered as must run, 28.0 percent were the economic minimum MW for dispatchable units, 51.7 percent were offered as a dispatchable range, and 0.6 percent were offered as emergency maximum MW.

Table 3-12 Dispatchable status of day-ahead energy offers: January through June, 2021

			Dispatchable Range											
Unit Type	Must Run	Eco Min	($300) - $0	$0 - $25	$25 - $50	$50 - $75	$75 - $100	$100 - $200	$200 - $400	$400 - $600	$600 - $800	$800 - $1000	Emergency MW	Dispatchable Percent
CC	6.7%	30.5%	0.0%	32.5%	20.3%	3.2%	1.7%	3.7%	0.7%	0.0%	0.0%	0.0%	0.6%	62.2%
CT	0.3%	53.4%	0.0%	3.4%	18.9%	4.4%	1.6%	12.5%	3.9%	0.4%	0.0%	0.0%	1.2%	45.1%
Diesel	0.0%	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Hydro	89.9%	0.0%	6.8%	3.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	10.1%
Nuclear	83.2%	6.3%	4.1%	6.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	10.5%
Solar	18.0%	0.1%	62.5%	18.4%	0.2%	0.3%	0.0%	0.5%	0.0%	0.0%	0.0%	0.0%	0.0%	81.9%
Steam - Coal	20.5%	19.2%	0.0%	30.9%	24.7%	2.3%	0.5%	0.2%	0.1%	1.0%	0.0%	0.0%	0.6%	59.6%
Steam - Other	4.1%	22.8%	1.1%	3.5%	32.9%	1.9%	1.0%	23.9%	8.3%	0.0%	0.0%	0.0%	0.4%	72.8%
Wind	6.3%	0.9%	84.3%	7.0%	1.3%	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	92.8%
Other	18.3%	41.7%	2.9%	7.6%	3.0%	3.1%	1.2%	15.0%	3.4%	0.0%	0.0%	0.0%	3.8%	36.2%
Total	19.6%	28.0%	2.1%	19.3%	18.6%	2.6%	1.1%	6.0%	1.8%	0.3%	0.0%	0.0%	0.6%	51.7%

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 3-13 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 six months of 2021, an average of 318 units per day made hourly offers, an increase of 18 units from 2020. In the first six months of 2021, 425 units opted in for intraday offer updates, an increase of 30 units from 2020. In the first six months of 2021, an average of 134 units made intraday offer updates each day, an increase of six units from 2020.

Table 3-13 Daily average number of units making hourly offers, opted in for intraday offers and making intraday offer updates: January through June, 2020 and 2021

	Fuel Type	2020	2021	Difference
Hourly Offers	Natural Gas	283	296	13
	Other Fuels	17	22	5
	Total	300	318	18
Opt In	Natural Gas	347	362	15
	Other Fuels	48	63	15
	Total	395	425	30
Intraday Offer Updates	Natural Gas	123	129	6
	Other Fuels	5	5	0
	Total	128	134	6

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.[23] 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.

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 3-14 shows average hourly MW, for each month, that violated the ICAP must offer requirement in the first six months of 2021. On average for all hours, 1,759 MW did not meet the ICAP must offer requirement, but for 10 percent of the hours 3,805 MW did not meet the must offer requirement. These MW levels are larger than the reserve shortages that triggered scarcity pricing in the first six months of 2021 and larger than most supply contingencies that led to synchronized reserve events in the first six months of 2021.

23 OA Schedule 1 § 1.10.1A(d).

Table 3-14 Average hourly estimated capacity (MW) failing the ICAP must offer requirement: January through June, 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	1,949	1,221	628
2021	3,805	1,759	311

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.[24]

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.[25]

The MMU recommends that capacity resources not be allowed to offer any portion of their capacity market obligation as maximum emergency energy.[26] 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 3-15 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 January 2021 had maximum emergency MW greater than or equal to 2,966 MW while 10 percent of hours in January 2021 had maximum emergency MW less than 1,778 MW. The hourly average, in the first six months of 2021, was 2,115 MW offered as maximum emergency, 6.3 percent lower than in 2020.

Table 3-15 Maximum emergency MW by month: January through June, 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
2021	2,830	2,115	1,536

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

25 OA Schedule 1 § 1.10.1A (d)

26 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).

Parameter Limited Schedules

Cost-Based Offers

All resources in PJM are required to submit at least one cost-based offer. For the 2020/2021 Delivery Year, PJM procured only capacity performance resources. 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 MMU recommends 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.[27] 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 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. The Commission recognized this flaw in the implementation of market power mitigation in its order to show cause, issued June 17, 2021.[28]

27 *See* Protest of the Independent Market Monitor for PJM, Docket No. ER20-995 (February 25, 2020).
28 See 175 FERC ¶ 61,231 (June 17, 2021).

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 six months of 2021. The analysis includes units with technologies that are subject to parameter limits and offer both price-based and cost-based schedules.[29] Table 3-16 shows the number and percentage of day-ahead unit run hours that failed the TPS test but were committed on price schedules. Table 3-16 shows that 35.1 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 3-16 Parameter mitigation for units failing TPS test: January through June, 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	15,744	35.1%
Committed on price schedule as flexible as cost	3,926	8.8%
Total committed on price schedule without parameter limits	19,670	43.9%
Committed on cost (cost capped)	24,952	55.7%
Committed on price PLS	185	0.4%
Total committed on PLS schedules (cost or price PLS)	25,137	56.1%

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 six months of 2021. PJM declared cold weather alerts on six days and hot weather alerts on six days in the first six months of 2021.[30] 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 3-17 shows that 31.8 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.[31] 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.

29 Nuclear, wind, solar and hydro units are not subject to parameter limits.
30 *2021 Quarterly State of the Market Report for PJM: January through June*, Section 3: Energy Market, at Emergency Procedures.
31 Nuclear, wind, solar and hydro units are not subject to parameter limits.

Table 3-17 Parameter mitigation during weather alerts: January through June, 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	9,796	31.8%
Committed on price schedule as flexible as PLS	2,058	6.7%
Total committed on price schedule without parameter limits	11,854	38.5%
Committed on cost (cost capped)	573	1.9%
Committed on price PLS	18,399	59.7%
Total committed on PLS schedules (cost or price PLS)	18,972	61.5%

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 MMU recommends that in order to ensure effective market power mitigation when the TPS test is failed and during high load conditions such as cold and hot weather alerts or more severe emergencies, the operating parameters in the cost-based offer and the price-based parameter limited schedule (PLS) offer be at least as flexible as the operating parameters in the available non-PLS price-based offer, and that the price-MW pairs in the price-based PLS offer be exactly equal to the price-based non-PLS offer. This recommendation would ensure that market power that results from inflexible parameters is mitigated during high load conditions and when a market seller fails the TPS test, consistent with the goal of having parameter limited schedules.

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 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.[32] 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 3-18 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 3-18 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.[33]

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.[34] 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 unit being committed, making the RTV a mechanism for exercising market power through withholding and for failing to meet the obligations of capacity resources. There were no defined negative consequences to market sellers for the use of real time values to withhold generation in the PJM market rules.

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 real-time values 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.

PJM's proposed RTV mechanism was rejected by the Commission because it would weaken the existing market power mitigation rules including parameter limited schedules.[35] PJM's practice of allowing units to use real time values, which was not a tariff defined mechanism, continued to undermine parameter mitigation by allowing resources to use inflexible parameters on their parameter limited schedules, for economic reasons, without any defined consequence. PJM's practice of units using real time values to increase their notification time continued to allow physical withholding and avoiding

32 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>.
33 175 FERC ¶ 61,171 (2021).

34 See OA Schedule 1 § 3.2.3(e).
35 *Id.* at P 36.

commitment. The MMU recommends that PJM institute rules that would not pay a share of capacity market revenue to resources that choose to submit real-time values that are less flexible than their unit specific parameter limits or approved parameter limit exceptions based on tariff defined reasons.

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.[36] The Commission directed that capacity performance resources with parameters based on nonphysical constraints should receive uplift payments.[37] 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.[38]

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.

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

36 151 FERC ¶ 61,208 at P 437 (2015) (June 9th Order).
37 *Id* at P 439.
38 *Id* at P 440.

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 3-19 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 six months of 2021, there were 54 units in PJM, with a total installed capacity of 7,196 MW that requested a 24 hour minimum run time on their parameter limited schedules based on pipeline restrictions.

Table 3-19 Units with 24 hour minimum run times due to gas pipeline restrictions: January through June, 2017 to 2021[39]

Year (Jan - Jun)	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	54	7,196

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

39 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.

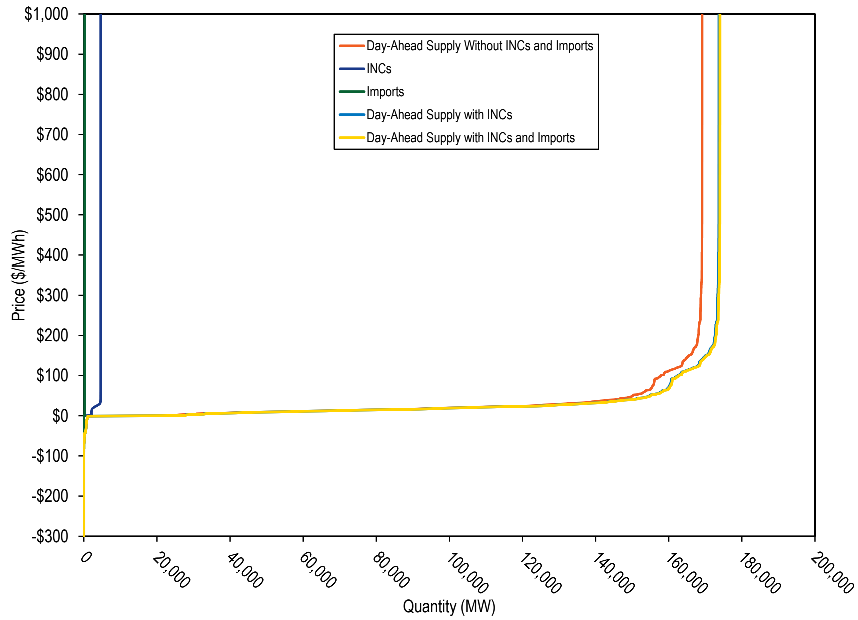
Virtual Offers and Bids

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.[40] Up to congestion transactions may be submitted between any two buses on a list of 47 buses eligible for up to congestion transaction bidding.[41] 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 3-18 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 3-18 Day-ahead aggregate supply curves: 2021 example day



40 162 FERC ¶ 61,139.

41 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 3-20 shows the hourly average number of cleared and submitted increment offers and decrement bids by month for 2020 and the first six months of 2021. The hourly average submitted increment MW decreased by 13.2 percent and cleared increment MW decreased by 4.9 percent in the first six months of 2021 compared to the first six months of 2020. The hourly average submitted decrement MW increased by 29.3 percent and cleared decrement MW increased by 17.5 percent in the first six months of 2021 compared to the first six months of 2020.

Table 3-20 Average hourly number of cleared and submitted INCs and DECs by month: January 2020 through June 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	Jan-Jun	2,423	6,100	255	929	4,218	9,991	244	1,074

Table 3-21 shows the average hourly number of up to congestion transactions and the average hourly MW from by month in 2020 and the first six months of 2021. The hourly average submitted up to congestion bid MW decreased by 50.1 percent and cleared MW decreased by 59.8 percent in the first six months of 2021 compared to the first six months of 2020.

Table 3-21 Average hourly cleared and submitted up to congestion bids by month: January 2020 through June 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	Jan-Jun	7,855	21,396	579	1,116

Table 3-22 shows the average hourly number of day-ahead import and export transactions and the average hourly MW from January 2020 through June 2021. In the first six months of 2021, the average hourly submitted import transaction MW increased by 2.1 percent and the average hourly cleared import transaction MW decreased by 2.8 percent compared to the first six months of 2020. The average hourly submitted and cleared export transaction MW decreased by 3.6 and 4.4 percent compared to the first six months of 2020.

Table 3-22 Hourly average day-ahead number of cleared and submitted import and export transactions by month: January 2020 through June 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	Jan-Jun	249	276	3	3	2,977	3,008	29	29

Table 3-23 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 June 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.[42]

Table 3-23 Type of day-ahead marginal resources: January 2020 through June 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%						
Aug	10.5%	0.0%	55.3%	24.9%	9.2%	0.0%						
Sep	13.1%	0.1%	54.8%	21.9%	10.1%	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%	20.4%	0.2%	36.5%	25.1%	17.7%	0.0%

42 172 FERC ¶ 61,046 (2020).

Figure 3-19 shows the monthly volume of bid and cleared INC, DEC and up to congestion bids by month from 2005 through June 2021.

Figure 3-19 Monthly bid and cleared INCs, DECs and UTCs (GWh): January 2005 through June 2021

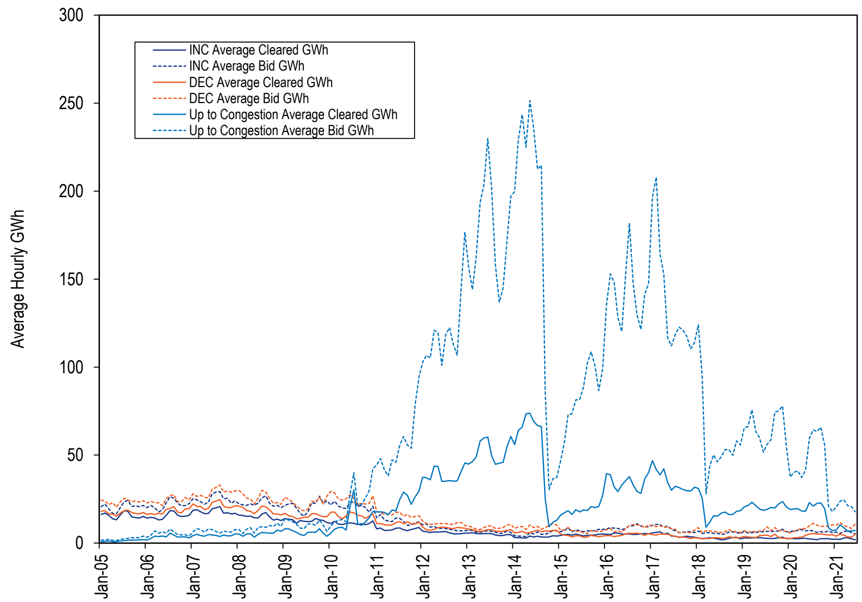
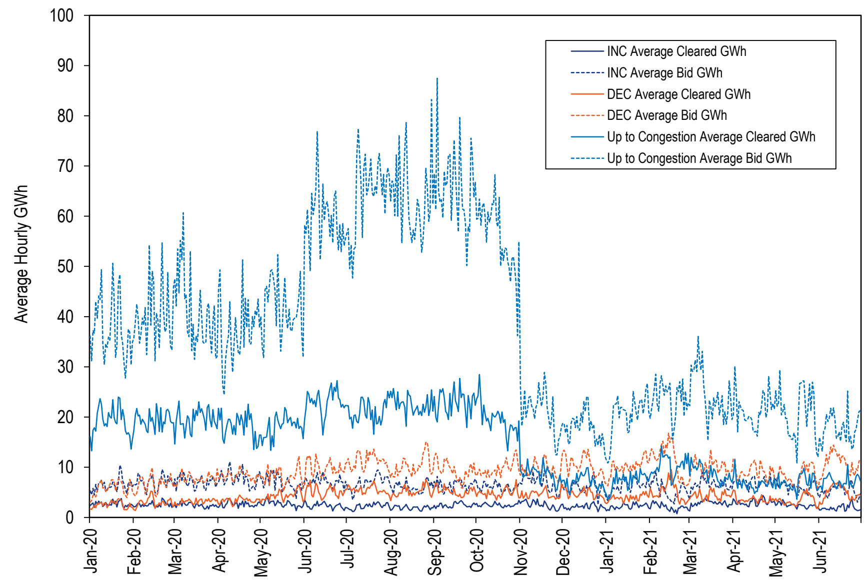


Figure 3-20 shows the daily volume of bid and cleared INC, DEC and up to congestion bids from January 2020 through June 2021.

Figure 3-20 Daily bid and cleared INCs, DECs, and UTCs (GWh): January 2020 through June 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 3-24 shows, in the first six months of 2020 and 2021, the total increment offers and decrement bids and cleared MW by type of parent organization.

Table 3-24 INC and DEC bids and cleared MWh by type of parent organization (MWh): January through June, 2020 and 2021

	2020 (Jan-Jun)				2021 (Jan-Jun)			
Category	Total Virtual Bid MWh	Percent	Total Virtual Cleared MWh	Percent	Total Virtual Bid MWh	Percent	Total Virtual Cleared MWh	Percent
Financial	55,146,844	85.2%	21,943,638	81.6%	63,304,886	90.7%	23,770,687	82.6%
Physical	9,565,968	14.8%	4,950,243	18.4%	6,521,335	9.3%	5,024,155	17.4%
Total	64,712,812	100.0%	26,893,881	100.0%	69,826,221	100.0%	28,794,842	100.0%

Table 3-25 shows, in the first six months of 2020 and 2021, the total up to congestion bids and cleared MWh by type of parent organization.

Table 3-25 Up to congestion transactions by type of parent organization (MWh): January through June, 2020 and 2021

	2020 (Jan-Jun)				2021 (Jan-Jun)			
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	169,950,493	90.9%	76,974,619	90.2%	81,851,857	88.1%	29,264,279	85.8%
Physical	17,057,937	9.1%	8,403,870	9.8%	11,072,051	11.9%	4,850,465	14.2%
Total	187,008,431	100.0%	85,378,488	100.0%	92,923,908	100.0%	34,114,743	100.0%

Table 3-26 shows, in the first six months of 2020 and 2021, the total import and export transactions by whether the parent organization was financial or physical.

Table 3-26 Import and export transactions by type of parent organization (MWh): January through June, 2020 and 2021

		2020 (Jan-Jun)		2021 (Jan-Jun)	
	Category	Total Import and Export MWh	Percent	Total Import and Export MWh	Percent
Day-Ahead	Financial	5,177,737	35.2%	5,217,416	37.6%
	Physical	9,547,594	64.8%	8,669,810	62.4%
	Total	14,725,330	100.0%	13,887,226	100.0%
Real-Time	Financial	7,716,943	29.9%	7,204,786	28.3%
	Physical	18,067,743	70.1%	18,239,479	71.7%
	Total	25,784,687	100.0%	25,444,265	100.0%

Table 3-27 shows increment offers and decrement bids by top 10 locations in the first six months of 2020 and 2021.

Table 3-27 Virtual offers and bids by top 10 locations (MWh): January through June, 2020 and 2021

2020 (Jan-Jun)					2021 (Jan-Jun)				
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	26,971	3,560,904	3,587,875	MISO	INTERFACE	104,469	3,312,282	3,416,752
WESTERN HUB	HUB	369,326	1,083,234	1,452,560	WESTERN HUB	HUB	421,138	946,818	1,367,956
AEP-DAYTON HUB	HUB	161,857	620,286	782,144	LINDENVFT	INTERFACE	29,495	861,018	890,513
BGE_RESID_AGG	RESIDUAL METERED EDC	156,360	609,870	766,230	DOM_RESID_AGG	RESIDUAL METERED EDC	91,306	753,826	845,133
DOM_RESID_AGG	RESIDUAL METERED EDC	94,861	632,232	727,092	AEP-DAYTON HUB	HUB	171,086	595,111	766,197
PECO_RESID_AGG	RESIDUAL METERED EDC	389,685	99,669	489,354	BGE_RESID_AGG	RESIDUAL METERED EDC	98,065	572,407	670,472
NORTHWEST	INTERFACE	364,381	105,376	469,758	NYIS	INTERFACE	328,968	339,596	668,564
N ILLINOIS HUB	HUB	171,493	260,760	432,253	N ILLINOIS HUB	HUB	216,552	399,859	616,411
NYIS	INTERFACE	394,017	31,665	425,681	COMED_RESID_AGG	RESIDUAL METERED EDC	194,003	306,048	500,052
PPL_RESID_AGG	RESIDUAL METERED EDC	330,291	75,809	406,100	HUDSONTP	INTERFACE	25,308	461,869	487,177
Top ten total		2,459,242	7,079,805	9,539,047			1,680,391	8,548,835	10,229,226
PJM total		11,188,379	15,748,543	26,936,922			10,521,283	18,319,319	28,840,602
Top ten total as percent of PJM total		22.0%	45.0%	35.4%			16.0%	46.7%	35.5%

Table 3-28 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 six months of 2020 and 2021. While the total cleared MWh were much lower in the first six months of 2021 compared to the first six months of 2020, total revenues were higher in the first six 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 interface, trades located at these two nodes were among the largest sources of revenue for up to congestion transactions in 2020.[43]

Table 3-28 Cleared up to congestion bids by top 10 source and sink pairs (MWh): January through June, 2020 and 2021

2020 (Jan-Jun)							
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	2,520,539	$2,127,741	($1,137,955)	$989,785
AEP GEN HUB	HUB	AEPOHIO_RESID_AGG	AGGREGATE	2,269,083	($61,990)	$292,072	$230,082
NORTHWEST	INTERFACE	COMED_RESID_AGG	AGGREGATE	2,231,016	$1,459,200	($191,668)	$1,267,532
SMECO_RESID_AGG	AGGREGATE	BGE_RESID_AGG	AGGREGATE	2,213,226	$223,583	($163,412)	$60,170
COMED_RESID_AGG	AGGREGATE	NIPSCO	INTERFACE	1,565,759	$1,394,315	($951,202)	$443,113
NORTHWEST	INTERFACE	CHICAGO GEN HUB	HUB	1,389,204	$1,246,554	($870,092)	$376,461
AEP GEN HUB	HUB	EKPC_RESID_AGG	AGGREGATE	1,328,174	$248,162	$70,501	$318,663
N ILLINOIS HUB	HUB	AEPIM_RESID_AGG	AGGREGATE	1,262,526	$63,265	$367,843	$431,108
NORTHWEST	INTERFACE	MISO	INTERFACE	1,244,193	$1,121,893	($440,648)	$681,245
OVEC_RESID_AGG	AGGREGATE	DAY_RESID_AGG	AGGREGATE	1,195,478	($5,065)	($75,227)	($80,292)
Top ten total				17,219,198	$7,817,658	($3,099,788)	$4,717,870
PJM total				82,425,058	$5,683,587	$7,696,122	$13,379,709
Top ten total as percent of PJM total				20.9%	137.5%	(40.3%)	35.3%
2021 (Jan-Jun)							
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	1,621,626	$1,483,213	($106,309)	$1,376,904
AEP GEN HUB	HUB	EKPC_RESID_AGG	AGGREGATE	1,420,390	$1,407,848	($400,780)	$1,007,068
SMECO_RESID_AGG	AGGREGATE	BGE_RESID_AGG	AGGREGATE	771,915	$1,058,271	($637,060)	$421,211
CHICAGO GEN HUB	HUB	AEPIM_RESID_AGG	AGGREGATE	657,011	$597,719	($2,309)	$595,410
MISO	INTERFACE	AEPIM_RESID_AGG	AGGREGATE	570,105	$936,452	($108,918)	$827,534
CHICAGO GEN HUB	HUB	MISO	INTERFACE	551,742	($559,479)	$804,059	$244,580
N ILLINOIS HUB	HUB	AEPIM_RESID_AGG	AGGREGATE	542,750	$414,036	$94,011	$508,047
CHICAGO GEN HUB	HUB	EKPC_RESID_AGG	AGGREGATE	518,374	$126,149	$132,148	$258,297
AEP GEN HUB	HUB	AEPOHIO_RESID_AGG	AGGREGATE	505,486	$182,672	$122,386	$305,057
COMED_RESID_AGG	HUB	DEOK_RESID_AGG	AGGREGATE	440,675	$480,842	($227,364)	$253,478
Top ten total				7,600,075	$6,127,722	($330,137)	$5,797,585
PJM total				34,114,743	$29,709,923	$2,199,009	$31,908,932
Top ten total as percent of PJM total				22.3%	20.6%	(15.0%)	18.2%

43 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 3-29 shows the average daily number of source-sink pairs that were offered and cleared each month from January 2020 through June 2021. Since November 2020, there has been a decrease in the average number of paths with submitted and cleared bids.

Table 3-29 Number of offered and cleared source and sink pairs: January 2020 through June 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	Jan-Jun	1,301	1,509	1,177	1,379

Table 3-30 and Figure 3-21 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 six months of 2020 and 2021. Total cleared up to congestion transactions decreased by 60.0 percent from 85.4 million MWh in the first six months of 2020 to 34.1 million MWh in the first six months of 2021. Internal up to congestion transactions in the first six months of 2021 were 80.2 percent of all up to congestion transactions compared to 65.5 percent in the first six months of 2020.

Table 3-30 Cleared up to congestion transactions and share of top 10 paths by type (MW): January through June, 2020 and 2021

	2020 (Jan-Jun)				
	Cleared Up to Congestion Bids				
	Import	Export	Wheel	Internal	Total
Top ten total (MW)	9,910,974	5,790,483	4,162,158	13,050,899	32,914,514
PJM total (MW)	16,364,450	8,519,048	4,542,415	55,952,575	85,378,488
Top ten total as percent of PJM total	60.6%	68.0%	91.6%	23.3%	38.6%
PJM total as percent of all up to congestion transactions	19.2%	10.0%	5.3%	65.5%	100.0%
	2021 (Jan-Jun)				
	Cleared Up to Congestion Bids				
	Import	Export	Wheel	Internal	Total
Top ten total (MW)	1,751,494	1,972,647	359,089	7,321,612	11,404,843
PJM total (MW)	3,104,438	3,201,002	445,873	27,363,431	34,114,743
Top ten total as percent of PJM total	56.4%	61.6%	80.5%	26.8%	33.4%
PJM total as percent of all up to congestion transactions	9.1%	9.4%	1.3%	80.2%	100.0%

Figure 3-21 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.[44] 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.[45] 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.[46]

44 See 162 FERC ¶ 61,139 (2018).
45 *Id.*
46 See 172 FERC ¶ 61,046 (2020).

Figure 3-21 Monthly cleared up to congestion transactions by type (MW): January 2005 through June 2021

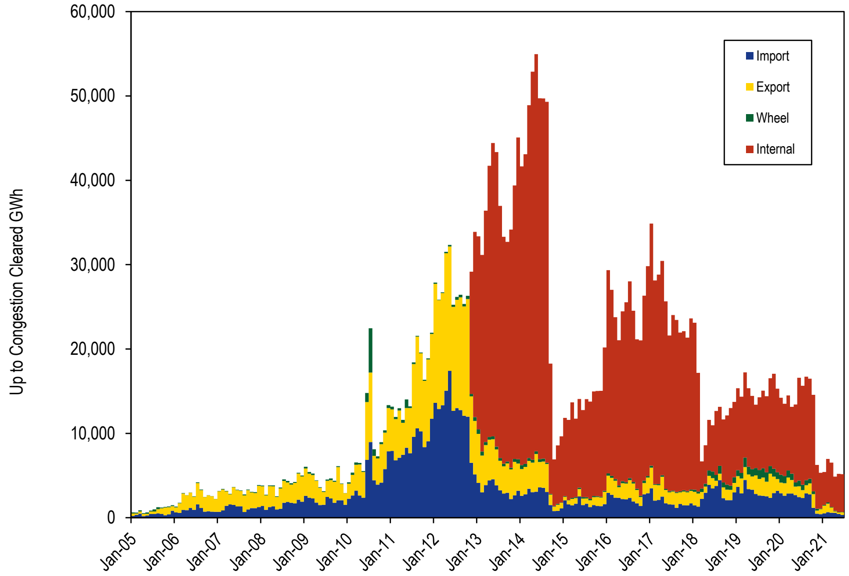
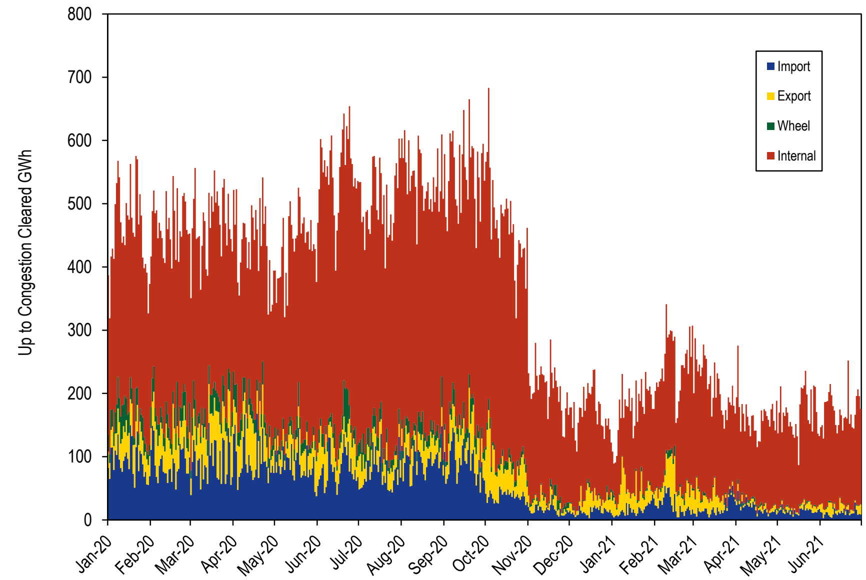


Figure 3-22 shows the daily cleared up to congestion MW by transaction type from January 1, 2020 through June 30, 2021.

Figure 3-22 Daily cleared up to congestion transaction by type (MW): January 2020 through June 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.[47]

47 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.[48] 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.

48 162 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 57.8 percent and 61.2 percent higher in the first six months of 2021 compared to the same time period of 2020.

The average real-time LMP in the first six months of 2021 increased 56.0 percent from the first six months of 2020, from $18.70 per MWh to $29.17 per MWh. The load-weighted average real-time LMP in the first six months of 2021 increased 57.8 percent from the first six months of 2020, from $19.40 per MWh to $30.62 per MWh.

The, load-weighted, average, real-time LMP for the first six months of 2021 was 50.6 percent lower than the fuel-cost adjusted, load-weighted, average, real-time LMP for the first six months of 2021. If fuel and emission costs in the first six months of 2021 had been the same as in the first six months of 2020, holding everything else constant, the load-weighted LMP would have been lower, $20.33 per MWh instead of the observed $30.62 per MWh.

The average day-ahead LMP in the first six months of 2021 increased 58.8 percent from the first six months of 2020, from $18.55 per MWh to $29.46 per MWh. The load-weighted average day-ahead LMP increased 61.2 percent from the first six months of 2020, from $19.23 per MWh to $31.00 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.[49] 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.[50]

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.

Real-Time Average LMP

Real-time, average LMP is the hourly average LMP for the PJM Real-Time Energy Market.[51]

PJM Real-Time, Average LMP

Table 3-31 shows the PJM real-time, average LMP for the first six months of 1998 through 2021.[52]

Table 3-31 Real-time, average LMP (Dollars per MWh): January through June, 1998 through 2021

	Real-Time LMP			Year to Year Change		
Jan-Jun	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$20.13	$15.90	$15.59	NA	NA	NA
1999	$22.94	$17.84	$41.16	14.0%	12.2%	164.0%
2000	$25.38	$18.03	$25.65	10.6%	1.1%	(37.7%)
2001	$33.10	$25.69	$21.11	30.4%	42.5%	(17.7%)
2002	$24.10	$19.64	$13.21	(27.2%)	(23.6%)	(37.4%)
2003	$41.31	$33.74	$27.81	71.4%	71.8%	110.6%
2004	$44.99	$40.75	$22.97	8.9%	20.8%	(17.4%)
2005	$45.71	$39.80	$23.51	1.6%	(2.3%)	2.3%
2006	$49.36	$43.46	$25.26	8.0%	9.2%	7.5%
2007	$55.03	$48.05	$31.42	11.5%	10.6%	24.4%
2008	$70.19	$59.53	$41.77	27.6%	23.9%	33.0%
2009	$40.12	$35.42	$19.30	(42.8%)	(40.5%)	(53.8%)
2010	$43.27	$37.11	$22.20	7.9%	4.8%	15.0%
2011	$45.51	$37.40	$32.52	5.2%	0.8%	46.5%
2012	$29.74	$28.32	$16.10	(34.6%)	(24.3%)	(50.5%)
2013	$36.56	$32.79	$17.18	22.9%	15.8%	6.7%
2014	$62.14	$39.69	$88.87	69.9%	21.0%	417.4%
2015	$38.87	$29.04	$34.04	(37.4%)	(26.8%)	(61.7%)
2016	$25.84	$23.17	$13.61	(33.5%)	(20.2%)	(60.0%)
2017	$28.72	$25.76	$12.03	11.1%	11.2%	(11.6%)
2018	$38.82	$27.21	$38.76	35.2%	5.6%	222.3%
2019	$26.41	$23.81	$15.75	(32.0%)	(12.5%)	(59.4%)
2020	$18.70	$17.54	$8.46	(29.2%)	(26.3%)	(46.3%)
2021	$29.17	$23.89	$21.30	56.0%	36.2%	151.8%

49 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.

50 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).

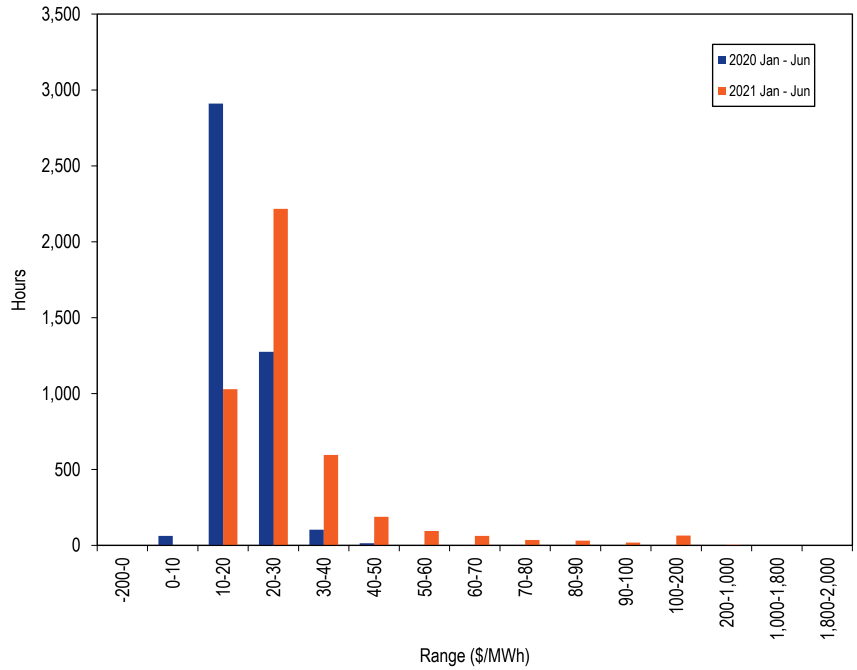
51 See the *Technical Reference for PJM Markets*, at "Calculating Locational Marginal Price," p 16-18 for detailed definition of Real-Time LMP. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

52 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 3-23 shows the hourly distribution of PJM real-time, average LMP for the first six months of 2020 and 2021. There were 2,910 hours with an average LMP between the $10 to $20 per MWh in the first six months of 2020, but only 1,029 hours were in the same range in the first six months of 2021.

Figure 3-23 Average LMP for the real-time energy market: January through June, 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 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 3-32 shows the PJM real-time, load-weighted, average LMP for the first six months of 1998 through 2021.

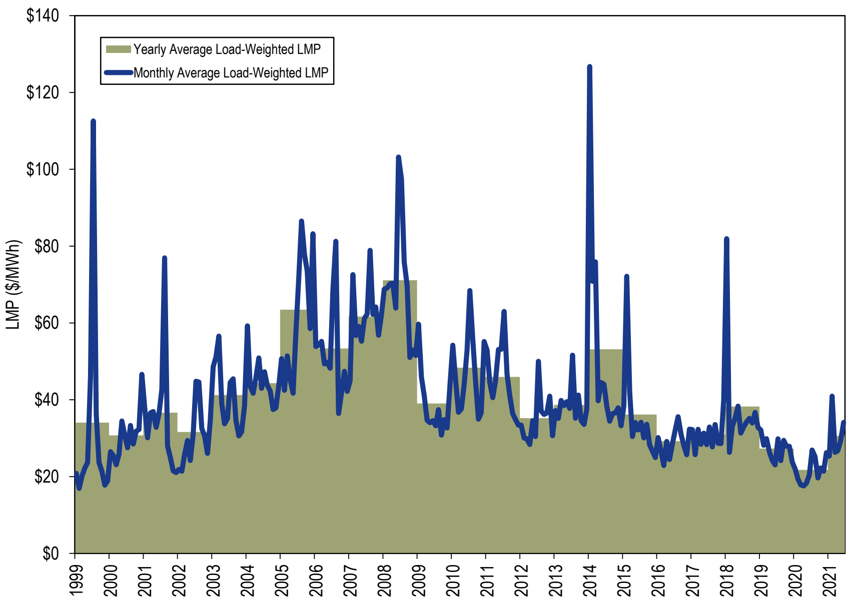
Table 3-32 Real-time, load-weighted, average LMP (Dollars per MWh): January through June, 1998 through 2021

	Real-Time, Load-Weighted, Average LMP			Year to Year Change		
Jan-Jun	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$21.66	$16.80	$18.39	NA	NA	NA
1999	$25.34	$18.59	$52.06	17.0%	10.7%	183.1%
2000	$27.76	$18.91	$29.69	9.5%	1.7%	(43.0%)
2001	$35.27	$27.88	$22.12	27.0%	47.4%	(25.5%)
2002	$25.93	$20.67	$14.62	(26.5%)	(25.9%)	(33.9%)
2003	$44.43	$37.98	$28.55	71.4%	83.8%	95.2%
2004	$47.62	$43.96	$23.30	7.2%	15.8%	(18.4%)
2005	$48.67	$42.30	$24.81	2.2%	(3.8%)	6.5%
2006	$51.83	$45.79	$26.54	6.5%	8.3%	7.0%
2007	$58.32	$52.52	$32.39	12.5%	14.7%	22.1%
2008	$74.77	$64.26	$44.25	28.2%	22.4%	36.6%
2009	$42.48	$36.95	$20.61	(43.2%)	(42.5%)	(53.4%)
2010	$45.75	$38.78	$23.60	7.7%	5.0%	14.5%
2011	$48.47	$38.63	$37.59	5.9%	(0.4%)	59.3%
2012	$31.21	$28.98	$17.69	(35.6%)	(25.0%)	(52.9%)
2013	$37.96	$33.58	$18.54	21.6%	15.9%	4.8%
2014	$69.92	$42.61	$103.35	84.2%	26.9%	457.6%
2015	$42.30	$30.34	$37.85	(39.5%)	(28.8%)	(63.4%)
2016	$27.09	$23.82	$14.49	(36.0%)	(21.5%)	(61.7%)
2017	$29.81	$26.47	$12.88	10.1%	11.1%	(11.1%)
2018	$42.44	$28.36	$43.68	42.4%	7.1%	239.1%
2019	$27.49	$24.40	$16.38	(35.2%)	(14.0%)	(62.5%)
2020	$19.40	$18.13	$8.93	(29.4%)	(25.7%)	(45.5%)
2021	$30.62	$24.61	$22.60	57.8%	35.7%	153.2%

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

Figure 3-24 shows the PJM real-time monthly and annual load-weighted LMP for January 1999 through June 2021.

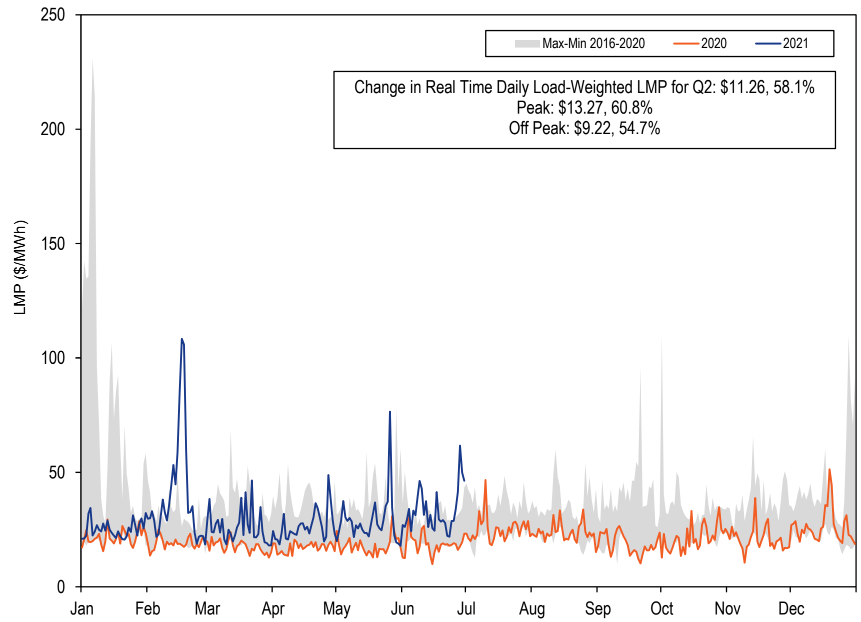
Figure 3-24 Real-time, monthly and annual, load-weighted, average LMP: January 1999 through June 2021



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

Figure 3-25 shows the PJM real-time, daily, load-weighted LMP for 2020 through the first six months of 2021.

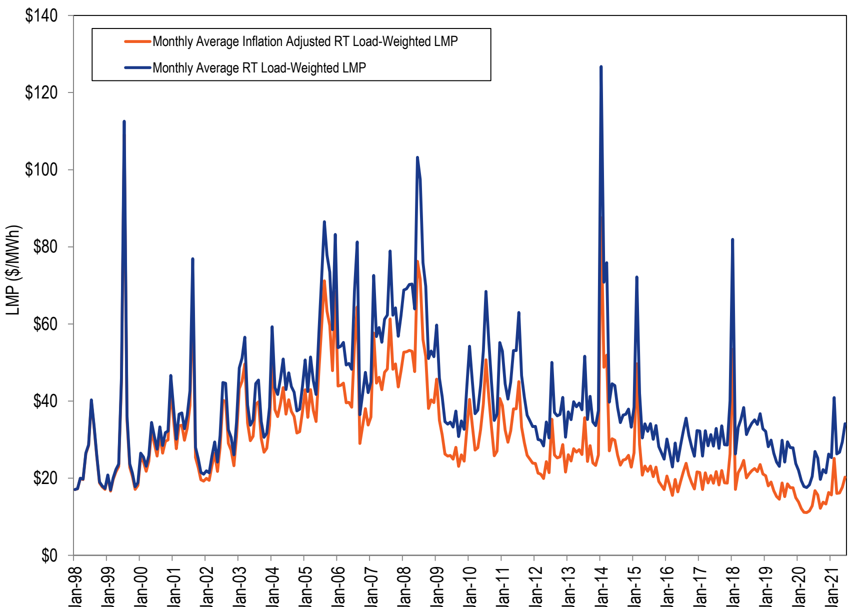
Figure 3-25 Real-time, daily, load-weighted, average LMP: January 2020 through June 2021



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

Figure 3-26 shows the PJM real-time, monthly, load-weighted, average LMP and inflation adjusted, monthly, load-weighted, average LMP from January 1998 through June 2021.[53] Table 3-33 shows the PJM real-time, load-weighted, average LMP and inflation adjusted load-weighted, average LMP for the first six months of every year from 1998 through 2021. The PJM real-time inflation adjusted, load-weighted, average LMP for the first six months of 2021 was the fourth lowest value since PJM real-time markets started on April 1, 1999 at $18.59 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 3-26 Real-time, monthly, load-weighted, average LMP unadjusted and adjusted for inflation: January 1998 through June 2021



53 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 July 13, 2021)

Table 3-33 Real-time, load-weighted, average LMP unadjusted and adjusted for inflation: January through June, 1998 through 2021

	Load-Weighted, Average LMP Jan-Jun	Inflation Adjusted Load-Weighted, Average LMP Jan-Jun
1998	$21.66	$21.54
1999	$25.34	$24.74
2000	$27.76	$26.25
2001	$35.27	$32.27
2002	$25.93	$23.40
2003	$44.43	$39.18
2004	$47.62	$41.02
2005	$48.67	$40.71
2006	$51.83	$41.78
2007	$58.32	$45.83
2008	$74.77	$56.29
2009	$42.48	$32.26
2010	$45.75	$33.99
2011	$48.47	$35.04
2012	$31.21	$22.05
2013	$37.96	$26.40
2014	$69.92	$47.96
2015	$42.30	$28.98
2016	$27.09	$18.34
2017	$29.81	$19.74
2018	$42.44	$27.48
2019	$27.49	$17.48
2020	$19.40	$12.17
2021	$30.62	$18.59

Real-Time Dispatch and Pricing

Currently, real-time dispatch and pricing are 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).[54] The final real-time LMPs and ancillary service clearing prices are determined for every five minute interval by LPC.

54 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 six 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 3-34 shows, on a monthly basis in the first six months of 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.

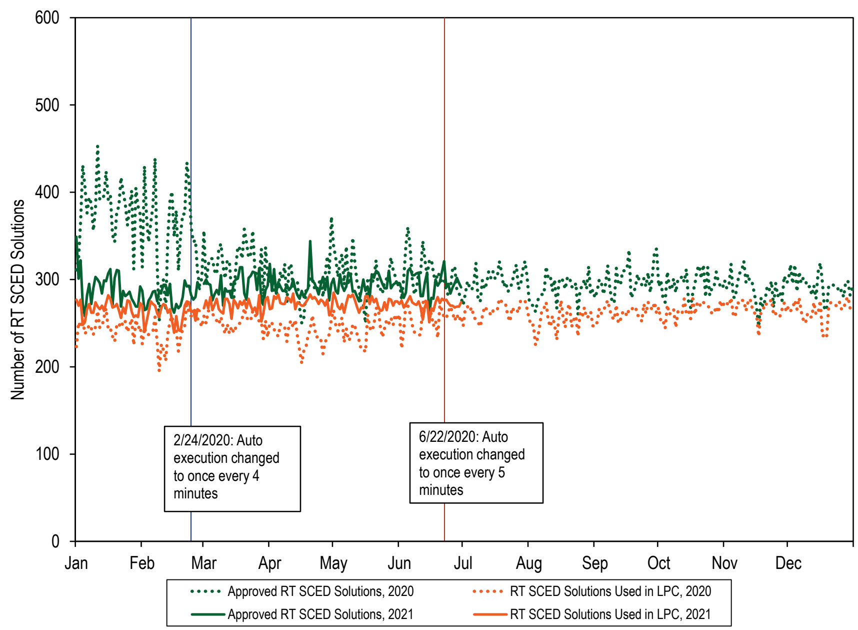
Table 3-34 shows that in the first six months of 2021, 92.5 percent of approved RT SCED solutions that were used to send dispatch signals to generators were used in calculating real-time energy market prices. The percent of approved solutions used for pricing increased in 2020 with the decrease in the frequency of executed RT SCED cases.

Figure 3-27 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 six months of 2021, and the dates when the frequency of RT SCED auto execution was changed in 2020. Figure 3-27 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 six months of 2021 relative to the first six months of 2020.

Table 3-34 RT SCED cases solved, approved and used in pricing: January through June, 2021

Month (2021)	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	31,395	9,022	8,276	91.7%
Feb	30,489	7,888	7,308	92.6%
Mar	32,456	9,069	8,372	92.3%
Apr	29,586	8,798	8,220	93.4%
May	30,438	9,124	8,468	92.8%
Jun	46,184	8,847	8,133	91.9%
Total	200,548	52,748	48,777	92.5%

Figure 3-27 Daily RT SCED solutions approved for dispatch signals and solutions used in pricing: January 2020 through June 2021



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 six 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 apply at the time when resources receive and follow that dispatch signal.[55] For example, the LPC case that calculates prices for the interval ending 10:05 EPT uses 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. There is still a mismatch between the MW dispatch and real-time LMPs that undermines generators' incentive to follow dispatch. The timing remains incorrect until all three (the pricing interval, the dispatch interval, and the RT SCED target time) all correspond to one another.

The extent to which dispatch instructions from approved SCED solutions are reflected in concurrent prices in the PJM Real-Time Energy Market can be

55 See Docket No. ER19-2573-000.

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 3-35 shows the average duration of the period when dispatch instructions corresponded to the prevailing prices in the first six 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 correspond to the dispatch instructions. Table 3-35 shows that during the first six months of 2021, the dispatch instructions were consistent with prevailing prices for only 34 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 reflect the dispatch signals from an approved RT SCED solution, dispatchers have approved a new solution, and resources are instructed to follow new dispatch signals that do not align with the LMPs used to settle the current five minute interval. In other words, prices consistently lag dispatch instructions by five minutes, except in cases where dispatchers have not approved a new SCED solution five minutes after a previously approved solution.

Table 3-35 Dispatch instructions reflected in prices: January through June, 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 - Jun 30, 2021	Every 5 minutes	00:34	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.[56] 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.[57] Under this proposal, RT SCED 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

56 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).
57 *See* PJM, "Enhancements to PJM Dispatch and Pricing – The 'Long-Term' Reforms," Docket No. ER21 – 1919 (May 17, 2021).

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.[58]

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.[59] Table 3-36 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 six months of 2021. In the first six months of 2021, PJM recalculated LMPs for 874 five minute intervals or 1.68 percent of the total 52,116 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 3-36 Number of five minute interval real-time prices recalculated: January 2020 through June 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	-	-
August	8,928	251	-	-
September	8,640	20	-	-
October	8,928	37	-	-
November	8,652	22	-	-
December	8,928	80	-	-
Total	105,408	943	52,116	874

58 The implementation of fast start pricing planned for September 1, 2021, will result in much more significant misalignment between price and dispatch signals.
59 OA Schedule 1 § 1.10.8(e).

Day-Ahead Average LMP

Day-ahead, average LMP is the hourly average LMP for the PJM Day-Ahead Energy Market.[60]

PJM Day-Ahead, Average LMP

Table 3-37 shows the PJM day-ahead, average LMP for the first six months of 2001 through 2021.

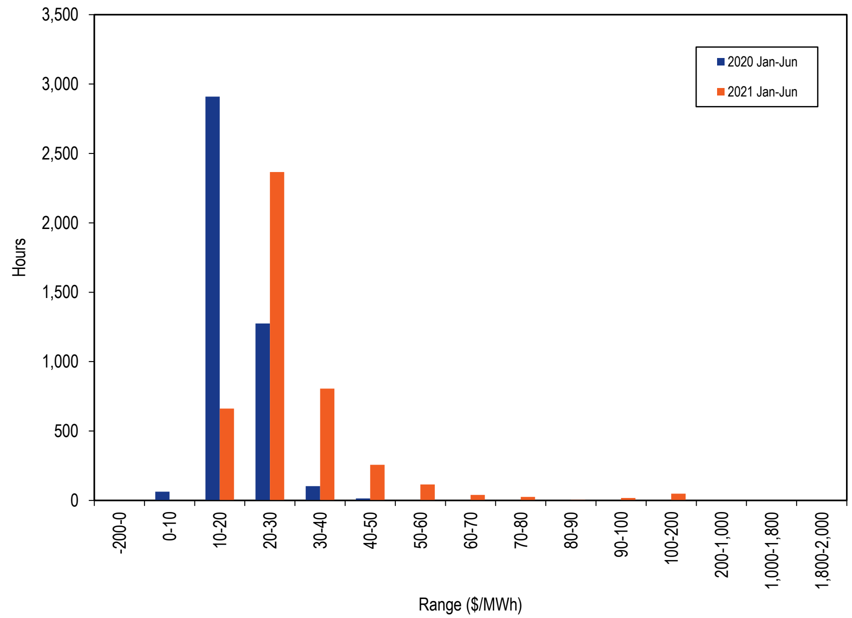
Table 3-37 Day-ahead, average LMP (Dollars per MWh): January through June, 2001 through 2021

	Day-Ahead LMP			Year to Year Change		
Jan-Jun	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2001	$35.02	$31.34	$17.43	NA	NA	NA
2002	$24.76	$21.28	$12.49	(29.3%)	(32.1%)	(28.4%)
2003	$42.83	$39.18	$23.52	73.0%	84.1%	88.3%
2004	$44.02	$43.14	$18.33	2.8%	10.1%	(22.0%)
2005	$45.63	$42.51	$18.35	3.7%	(1.5%)	0.1%
2006	$48.33	$47.07	$16.02	5.9%	10.7%	(12.7%)
2007	$53.03	$51.08	$22.91	9.7%	8.5%	43.0%
2008	$70.12	$66.09	$31.98	32.2%	29.4%	39.6%
2009	$40.01	$37.46	$15.38	(42.9%)	(43.3%)	(51.9%)
2010	$43.81	$40.64	$15.66	9.5%	8.5%	1.8%
2011	$44.75	$40.85	$19.53	2.1%	0.5%	24.8%
2012	$30.44	$29.64	$11.77	(32.0%)	(27.4%)	(39.8%)
2013	$37.11	$35.19	$10.42	21.9%	18.7%	(11.4%)
2014	$63.52	$44.42	$69.93	71.2%	26.2%	571.1%
2015	$39.98	$31.93	$28.76	(37.1%)	(28.1%)	(58.9%)
2016	$26.24	$24.95	$8.54	(34.4%)	(21.9%)	(70.3%)
2017	$29.03	$27.26	$8.87	10.6%	9.3%	3.9%
2018	$37.90	$30.08	$29.14	30.5%	10.3%	228.6%
2019	$26.86	$25.31	$9.56	(29.1%)	(15.8%)	(67.2%)
2020	$18.55	$18.20	$4.92	(30.9%)	(28.1%)	(48.6%)
2021	$29.46	$25.58	$15.30	58.8%	40.5%	211.3%

PJM Day-Ahead Average LMP Duration

Figure 3-28 shows the hourly distribution of PJM day-ahead, average LMP in the first six months of 2020 and 2021.

Figure 3-28 Average LMP for the day-ahead energy market: January through June, 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.

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

PJM Day-Ahead, Load-Weighted, Average LMP

Table 3-38 shows the PJM day-ahead, load-weighted, average LMP in the first six months of 2001 through 2021.

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

	Day-Ahead, Load-Weighted, Average LMP			Year to Year Change		
Jan-Jun	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2001	$37.08	$33.91	$18.11	NA	NA	NA
2002	$26.88	$23.00	$14.36	(27.5%)	(32.2%)	(20.7%)
2003	$45.62	$42.01	$23.96	69.7%	82.7%	66.8%
2004	$46.12	$45.45	$18.62	1.1%	8.2%	(22.3%)
2005	$48.12	$44.88	$19.24	4.3%	(1.3%)	3.3%
2006	$50.21	$48.67	$16.23	4.3%	8.5%	(15.7%)
2007	$55.70	$54.26	$23.47	10.9%	11.5%	44.7%
2008	$73.71	$69.33	$33.95	32.3%	27.8%	44.7%
2009	$42.21	$38.83	$16.16	(42.7%)	(44.0%)	(52.4%)
2010	$46.12	$42.50	$16.54	9.3%	9.5%	2.3%
2011	$47.12	$42.58	$22.34	2.2%	0.2%	35.1%
2012	$31.84	$30.35	$13.94	(32.4%)	(28.7%)	(37.6%)
2013	$38.23	$36.19	$11.03	20.1%	19.3%	(20.8%)
2014	$70.67	$47.04	$79.85	84.8%	30.0%	623.8%
2015	$43.26	$33.45	$32.23	(38.8%)	(28.9%)	(59.6%)
2016	$27.33	$25.92	$8.89	(36.8%)	(22.5%)	(72.4%)
2017	$30.02	$28.21	$9.38	9.8%	8.8%	5.6%
2018	$40.96	$31.44	$32.70	36.5%	11.4%	248.5%
2019	$27.97	$26.10	$10.59	(31.7%)	(17.0%)	(67.6%)
2020	$19.23	$18.73	$5.14	(31.3%)	(28.2%)	(51.4%)
2021	$31.00	$26.63	$16.73	61.2%	42.1%	225.4%

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

Figure 3-29 shows the PJM day-ahead, monthly and annual, load-weighted LMP from January 2001 through June 2021.

Figure 3-29 Day-ahead, monthly and annual, load-weighted, average LMP: January 2001 through June 2021

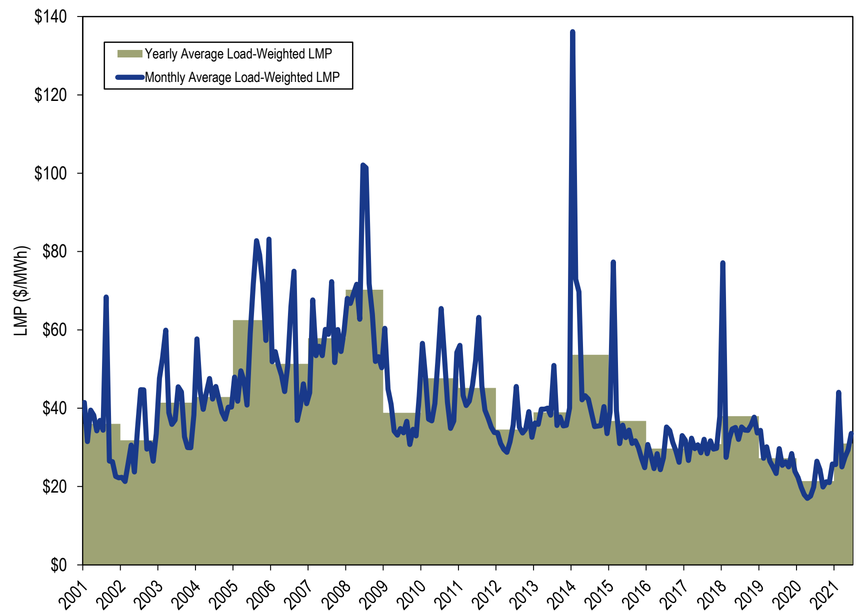
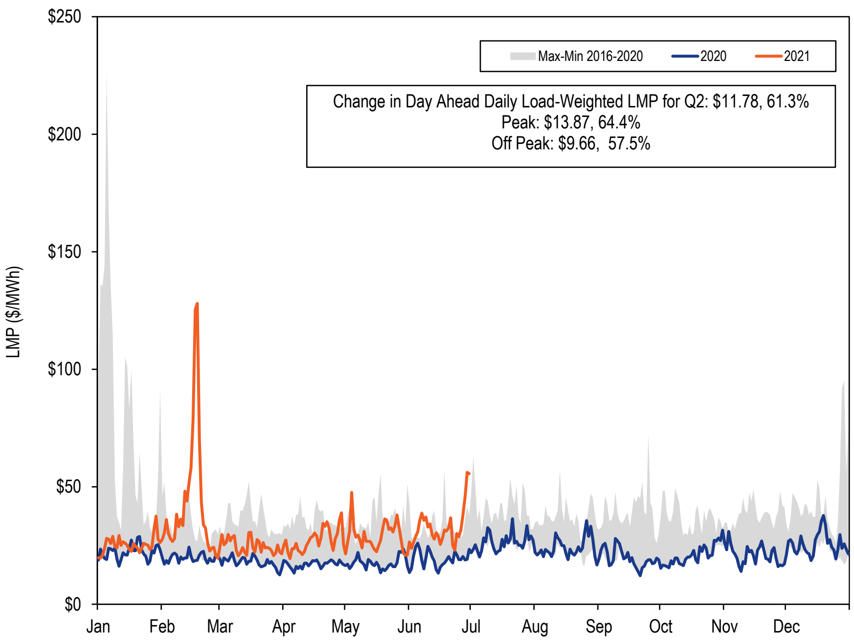


Figure 3-30 shows the PJM day-ahead daily, load-weighted, LMP in 2020 through the first six months 2021 compared to the historic five year price range.

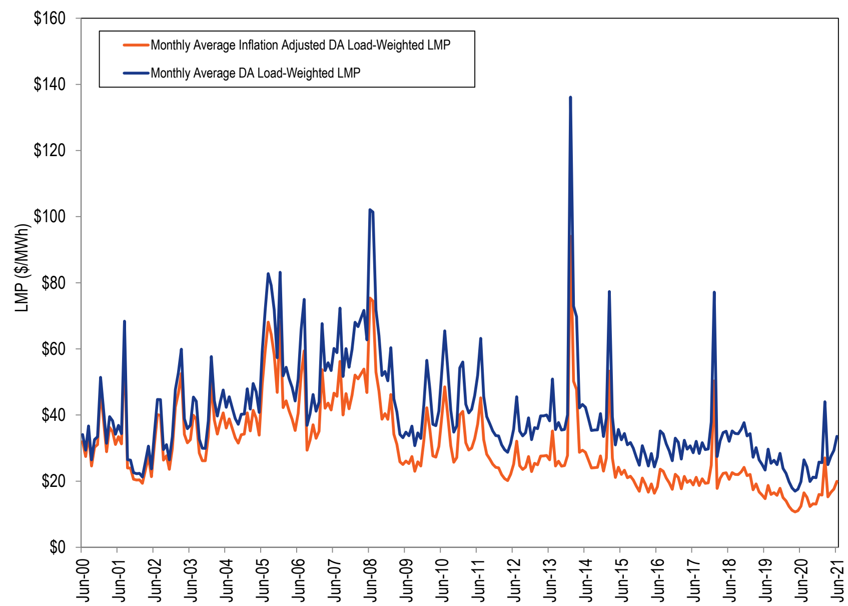
Figure 3-30 Day-ahead, daily, load-weighted, average LMP: January 2020 through June 2021



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

Figure 3-31 shows the PJM day-ahead, monthly, load-weighted, average LMP and inflation adjusted monthly day-ahead, load-weighted, average LMP for June 2000 through June 2021.[61] Table 3-39 shows the PJM day-ahead, load-weighted, average LMP and inflation adjusted load-weighted, average LMP for the first six months of every year from 2000 through 2021. The PJM day-ahead, inflation adjusted, load-weighted, average LMP for the first six months of 2021 was the fourth lowest ($18.82 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 3-31 Day-ahead, monthly, load-weighted, average LMP unadjusted and inflation adjusted: June 2000 through June 2021



61 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 July 13, 2021).

Table 3-39 Day-ahead, yearly, load-weighted, average LMP unadjusted and inflation adjusted: January through June, 2001 through 2021

	Load-Weighted, Average LMP Jan-Jun	Inflation Adjusted Load-Weighted, Average LMP Jan-Jun
2000	$34.12	$31.98
2001	$37.08	$33.94
2002	$26.88	$24.25
2003	$45.62	$40.23
2004	$46.12	$39.73
2005	$48.12	$40.24
2006	$50.21	$40.47
2007	$55.70	$43.76
2008	$73.71	$55.49
2009	$42.21	$32.06
2010	$46.12	$34.28
2011	$47.12	$34.08
2012	$31.84	$22.49
2013	$38.23	$26.59
2014	$70.67	$48.48
2015	$43.26	$29.64
2016	$27.33	$18.51
2017	$30.02	$19.88
2018	$40.96	$26.52
2019	$27.97	$17.79
2020	$19.23	$12.06
2021	$31.00	$18.82

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.

Table 3-40 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 six months of 2020 and 2021. In the first six months of 2021, 47.6 percent of all cleared UTC transactions received positive net revenues before uplift charges. Of cleared UTC transactions, 69.5 percent received positive revenues on the source side and 31.2 percent received positive revenues on the sink side, but only 8.0 percent received positive revenues on both the source and sink side.

Table 3-40 Cleared UTC count with positive revenues by source and sink point before uplift charges: January through June, 2020 and 2021[62]

(Jan-Jun)	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	4,872,175	2,540,498	3,025,710	1,866,187	356,062	52.1%	62.1%	38.3%	7.3%
2021	2,516,220	1,196,821	1,747,789	785,574	201,425	47.6%	69.5%	31.2%	8.0%

Table 3-41 shows the number of cleared INC and DEC transactions and the number of cleared transactions with positive revenues before uplift charges in the first six months of 2020 and 2021. Of cleared INC and DEC transactions in the first six months of 2021, 69.0 percent of INCs had positive revenues and 32.2 percent of DECs had positive revenues.

Table 3-41 Cleared INC and DEC count with positive revenues: January through June, 2020 and 2021

(Jan-Jun)	Cleared INC	Positive Revenue INC	Positive Revenue INC Share	Cleared DEC	Positive Revenue DEC	Positive Revenue DEC Share
2020	1,122,070	718,460	64.0%	1,187,461	475,213	40.0%
2021	1,108,541	764,682	69.0%	1,058,084	340,939	32.2%

62 Calculations exclude PJM administrative charges.

Figure 3-32 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 six months of 2021.

Figure 3-32 UTC daily positive, negative, and net revenues before uplift charges: January through June, 2021[63]

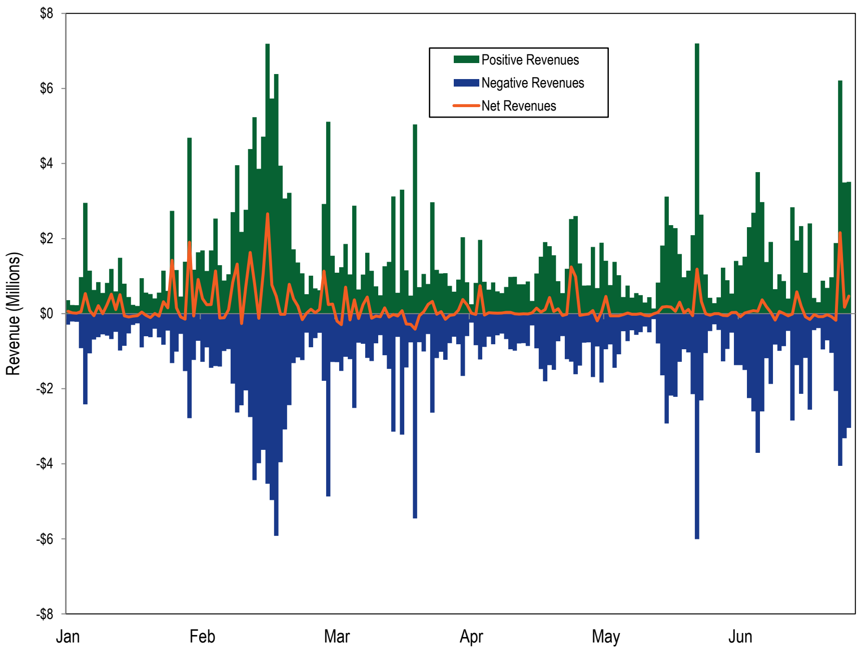
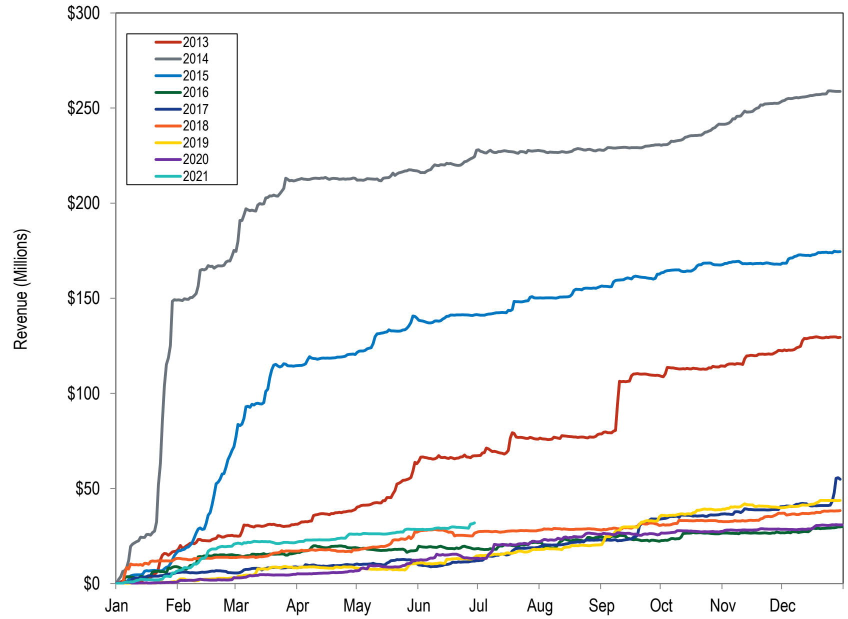


Figure 3-33 shows the cumulative UTC daily total net revenues before operating reserve charges for each year from 2013 through the first six months of 2021.

Figure 3-33 Cumulative daily UTC net revenues before operating reserve charges: January 2013 through June 2021



63 Calculations exclude PJM administrative charges.

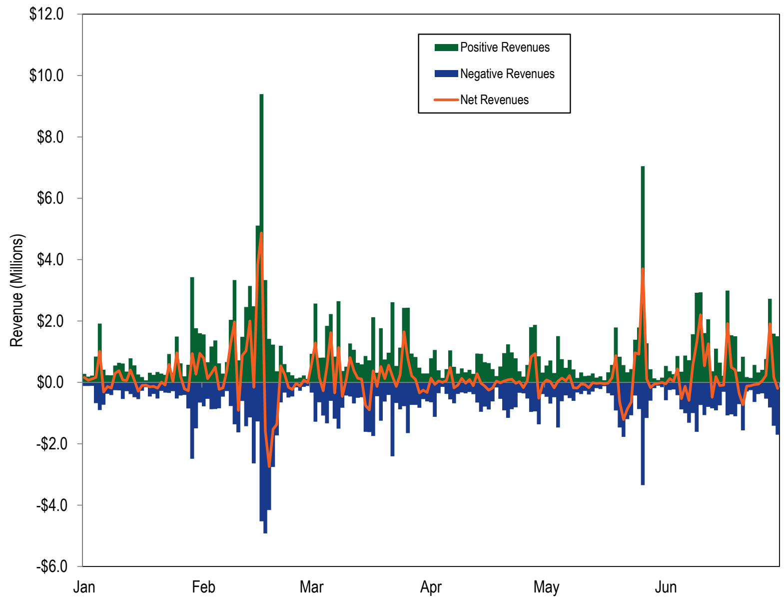
Table 3-42 shows UTC revenues before operating reserve charges by month for January 2013 through June 2021. May 2016, September 2016, February 2017, June 2018 and September 2020 were the only months in this seven year period in which monthly net revenues were negative.

Table 3-42 UTC net revenues before operating reserve charges by month: January 2013 through June 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							$31,908,932

Figure 3-34 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 six months of 2021.

Figure 3-34 INC and DEC daily positive, negative, and total revenues before uplift charges: January through June, 2021[64]



64 Calculations exclude PJM administrative charges.

Figure 3-35 shows total INC daily gross positive and negative revenues and net revenues before uplift charges in the first six months of 2021.

Figure 3-35 INC daily positive, negative, and total net revenues before uplift charges January through June, 2021[65]

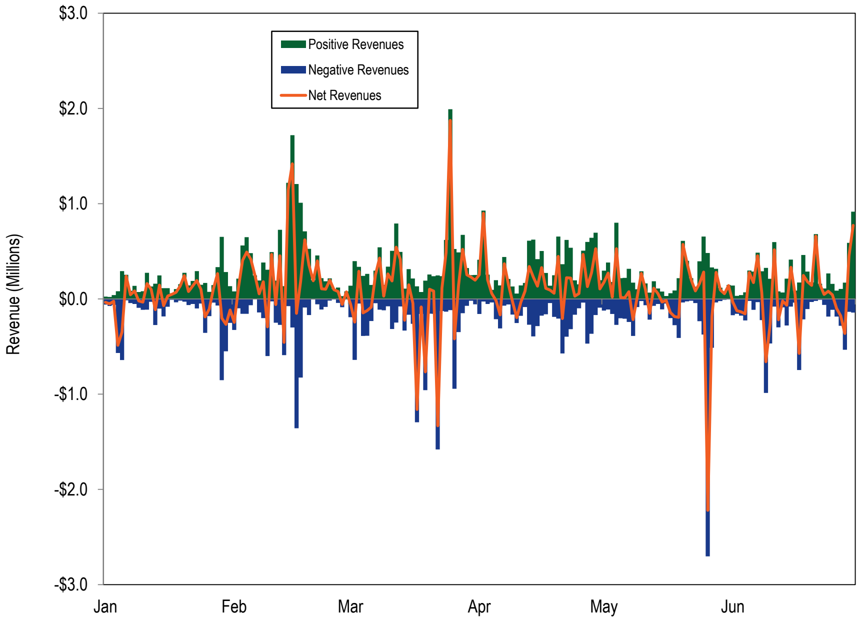
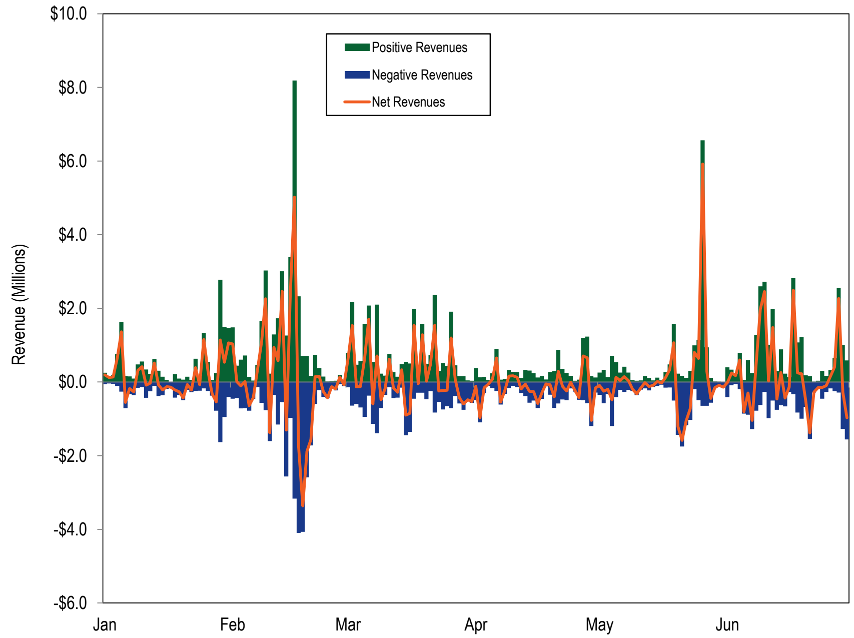


Figure 3-36 shows total DEC daily gross positive and negative revenues and net revenues before uplift charges in the first six months of 2021.

Figure 3-36 DEC daily positive, negative, and total net revenues before uplift charges: January through June, 2021[66]



65 Calculations exclude PJM administrative charges.

66 Calculations exclude PJM administrative charges.

Figure 3-37 shows the cumulative INC and DEC daily revenues before uplift charges for the first six months of 2021.

Figure 3-37 Cumulative daily INC and DEC revenues before uplift charges: January through June, 2021

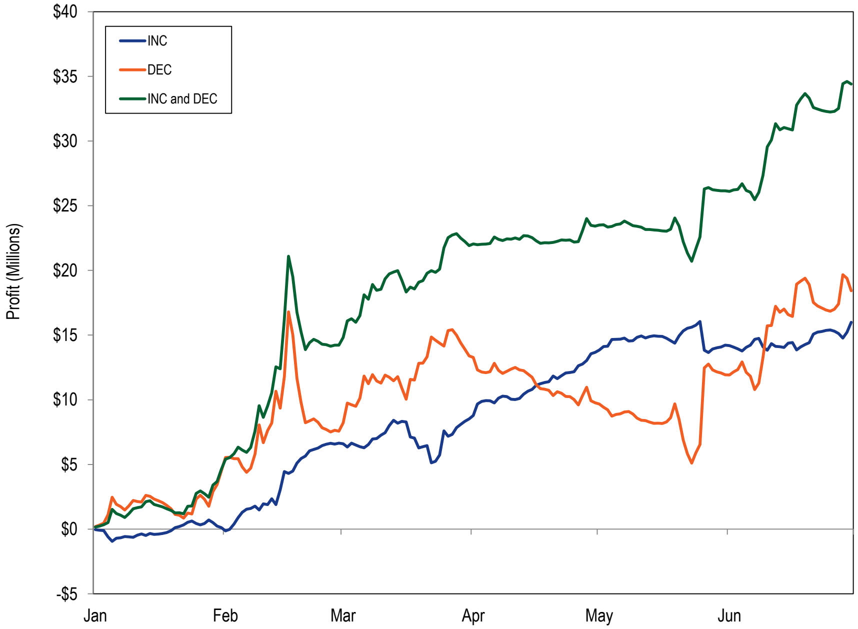


Table 3-43 shows INC and DEC revenues before uplift charges by month for the first six months of 2021.

Table 3-43 INC and DEC revenues before uplift charges by month: January through June, 2021

	January	February	March	April	May	June	Total
INCs	$116,313	$6,534,110	$1,874,664	$5,140,992	$554,421	$1,767,917	$15,988,416
DECs	$4,506,985	$3,060,102	$5,820,332	($3,623,933)	$2,168,601	$6,490,068	$18,422,156
INCs and DECs	$4,623,297	$9,594,212	$7,694,996	$1,517,059	$2,723,022	$8,257,985	$34,410,572

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.

Table 3-44 shows that the difference between the average real-time price and the average day-ahead price.

Table 3-44 Day-ahead and real-time average LMP (Dollars per MWh): January through June, 2020 and 2021[67]

	2020				2021			
Jan-Jun	Day-Ahead	Real-Time	Difference	Percent of Real Time	Day-Ahead	Real-Time	Difference	Percent of Real Time
Average	$18.55	$18.70	$0.15	0.8%	$29.46	$29.17	($0.29)	(1.0%)
Median	$18.20	$17.54	($0.66)	(3.8%)	$25.58	$23.89	($1.69)	(7.1%)
Standard deviation	$4.92	$8.46	$3.54	41.9%	$15.30	$21.30	$6.00	28.2%
Peak average	$21.09	$21.38	$0.30	1.4%	$34.13	$33.88	($0.24)	(0.7%)
Peak median	$20.07	$19.35	($0.72)	(3.7%)	$28.90	$26.48	($2.42)	(9.1%)
Peak standard deviation	$4.68	$10.05	$5.36	53.4%	$18.29	$26.71	$8.43	31.5%
Off peak average	$16.32	$16.33	$0.02	0.1%	$25.37	$25.03	($0.33)	(1.3%)
Off peak median	$16.03	$15.74	($0.29)	(1.9%)	$22.51	$21.65	($0.86)	(3.9%)
Off peak standard deviation	$3.93	$5.79	$1.86	32.1%	$10.49	$13.72	$3.23	23.6%

The price difference between the real-time and the day-ahead energy markets results in part, from conditions in the real-time energy market that are difficult, or impossible, to anticipate in the day-ahead energy market.

Table 3-45 shows the difference between the real-time load-weighted and the day-ahead load-weighted energy market prices for the first six months of 2001 through 2021.

Table 3-45 Day-ahead load-weighted and real-time loadeighted, average LMP (Dollars per MWh): January through June, 2001 through 2021

	Load-Weighted Average LMP			
Jan-Jun	Day-Ahead	Real-Time	Difference	Percent of Real Time
2001	$35.02	$33.10	($1.92)	(5.5%)
2002	$24.76	$24.10	($0.66)	(2.7%)
2003	$42.83	$41.31	($1.53)	(3.6%)
2004	$44.02	$44.99	$0.97	2.2%
2005	$45.63	$45.71	$0.07	0.2%
2006	$48.33	$49.36	$1.03	2.1%
2007	$53.03	$55.03	$2.00	3.8%
2008	$70.12	$70.19	$0.08	0.1%
2009	$40.01	$40.12	$0.11	0.3%
2010	$43.81	$43.27	($0.54)	(1.2%)
2011	$44.75	$45.51	$0.76	1.7%
2012	$30.44	$29.74	($0.69)	(2.3%)
2013	$37.11	$36.56	($0.55)	(1.5%)
2014	$63.52	$62.14	($1.38)	(2.2%)
2015	$39.98	$38.87	($1.11)	(2.8%)
2016	$26.24	$25.84	($0.40)	(1.5%)
2017	$29.03	$28.72	($0.31)	(1.1%)
2018	$37.90	$38.82	$0.93	2.4%
2019	$26.86	$26.41	($0.45)	(1.7%)
2020	$18.55	$18.70	$0.15	0.8%
2021	$29.46	$29.17	($0.29)	(1.0%)

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

Table 3-46 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 six months of 2020 and 2021.

Table 3-46 Frequency distribution by hours of real-time, load-weighted LMP minus day-ahead, load-weighted LMP (Dollars per MWh): January through June, 2020 and 2021

	2020 (Jan-Jun)		2021(Jan-Jun)	
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	0.14%	6	0.00%
($50) to $0	2,759	69.01%	2,991	63.18%
$0 to $50	1,598	98.92%	1,299	99.77%
$50 to $100	8	99.77%	37	99.95%
$100 to $200	2	99.91%	6	100.00%
$200 to $400	0	99.98%	3	100.00%
$400 to $800	0	100.00%	1	100.00%
>= $800	0	100.00%	0	100.00%

Figure 3-38 shows the hourly differences between day-ahead and real-time hourly LMP in the first six months of 2021.

Figure 3-38 Real-time hourly, LMP minus day-ahead hourly LMP: January through June, 2021

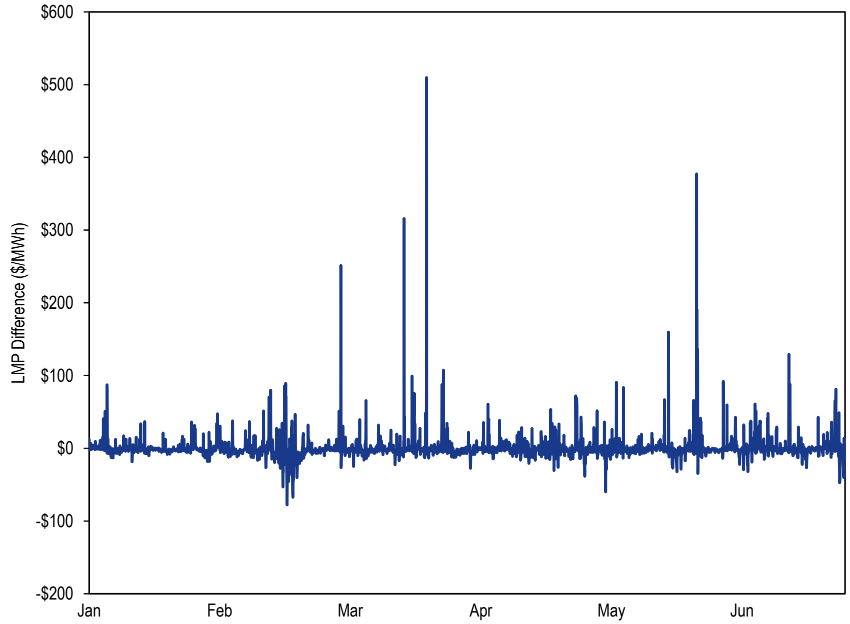
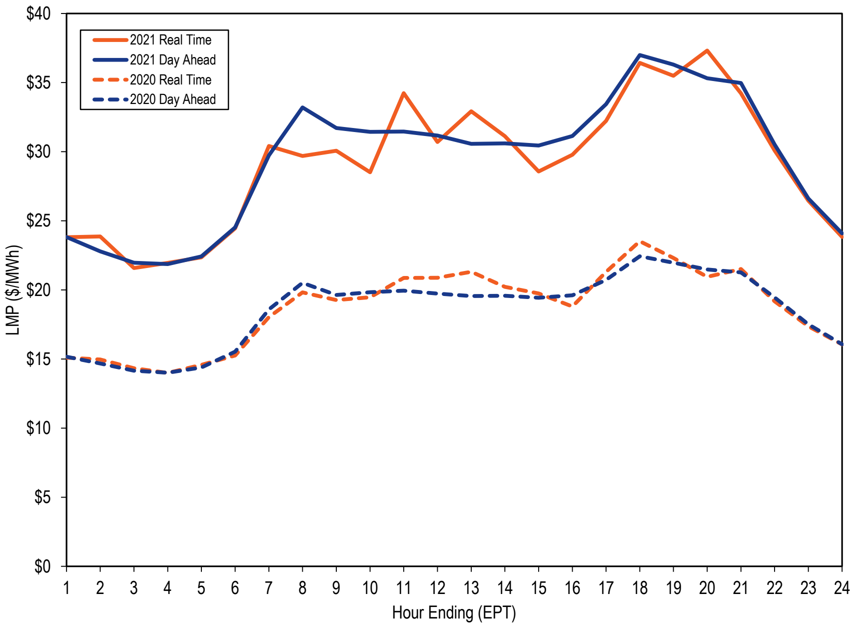


Figure 3-39 shows day-ahead and real-time, load-weighted, average hourly LMP for the first six months of 2020 and 2021.

Figure 3-39 System hourly average LMP: January through June, 2020 and 2021



Zonal LMP and Dispatch

Table 3-47 shows zonal real-time, and real-time, load-weighted, average LMP in the first six months of 2020 and 2021.

Table 3-47 Zonal real-time and real-time, load-weighted, average LMP (Dollars per MWh): January through June, 2020 and 2021

	Real-Time Average LMP			Real-Time, Load-Weighted, Average LMP		
Zone	2020 Jan-Jun	2021 Jan-Jun	Percent Change	2020 Jan-Jun	2021 Jan-Jun	Percent Change
ACEC	$17.31	$24.96	44.2%	$17.99	$26.61	47.9%
AEP	$19.27	$29.82	54.7%	$19.93	$31.12	56.1%
APS	$19.38	$28.94	49.3%	$20.06	$30.26	50.9%
ATSI	$19.54	$28.10	43.8%	$20.25	$29.29	44.6%
BGE	$20.25	$33.60	65.9%	$21.29	$35.61	67.3%
COMED	$17.15	$27.54	60.6%	$18.01	$29.22	62.2%
DAY	$20.14	$31.49	56.4%	$20.96	$33.33	59.0%
DUKE	$19.33	$30.64	58.5%	$20.08	$32.49	61.8%
DOM	$19.54	$32.38	65.7%	$20.35	$34.10	67.6%
DPL	$17.38	$31.42	80.8%	$18.10	$33.56	85.4%
DUQ	$19.70	$28.06	42.5%	$20.47	$29.43	43.8%
EKPC	$19.26	$29.73	54.4%	$20.10	$31.90	58.7%
JCPLC	$17.71	$24.79	40.0%	$18.53	$26.46	42.9%
MEC	$17.81	$26.89	51.0%	$18.57	$28.41	53.0%
OVEC	$18.90	$28.40	50.3%	$19.08	$28.79	50.9%
PECO	$17.04	$24.71	45.0%	$17.64	$26.17	48.4%
PE	$18.26	$26.94	47.5%	$18.81	$27.96	48.6%
PEPCO	$19.60	$31.52	60.9%	$20.55	$33.57	63.4%
PPL	$16.95	$25.56	50.8%	$17.56	$26.77	52.5%
PSEG	$17.52	$27.70	58.1%	$18.11	$29.39	62.3%
REC	$17.68	$30.70	73.7%	$18.39	$33.02	79.6%
PJM	$18.70	$29.17	56.0%	$19.40	$30.62	57.8%

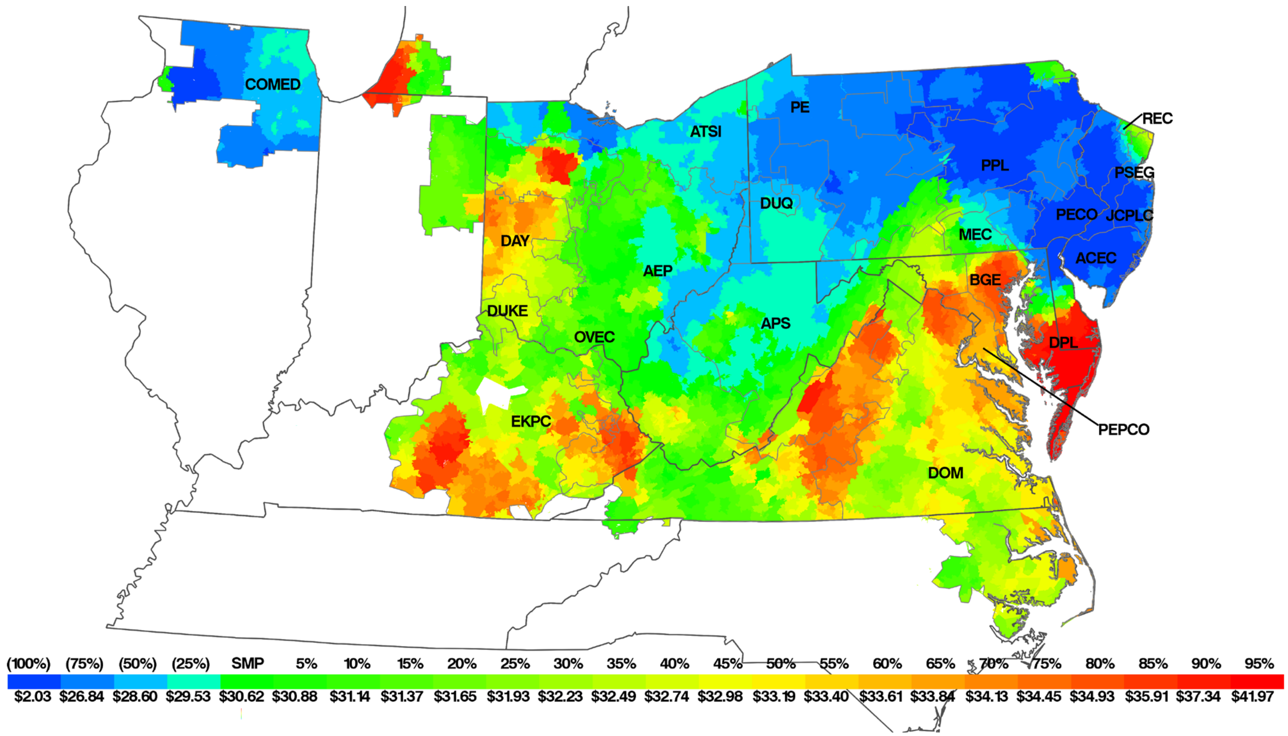
Table 3-48 shows zonal day-ahead, and day-ahead, load-weighted, average LMP in the first six months of 2020 and 2021.

Table 3-48 Zonal day-ahead and day-ahead, load-weighted, average LMP (Dollars per MWh): January through June, 2020 and 2021

	Day-Ahead Average LMP			Day-Ahead, Load-Weighted, Average LMP		
Zone	2020 Jan-Jun	2021 Jan-Jun	Percent Change	2020 Jan-Jun	2021 Jan-Jun	Percent Change
ACEC	$16.94	$25.61	51.2%	$17.53	$27.21	55.2%
AEP	$19.15	$30.02	56.7%	$19.81	$31.48	58.9%
APS	$19.12	$29.43	54.0%	$19.77	$30.73	55.4%
ATSI	$19.39	$29.37	51.5%	$20.03	$30.53	52.4%
BGE	$20.42	$33.76	65.3%	$21.45	$35.71	66.5%
COMED	$17.34	$27.74	59.9%	$18.08	$29.30	62.1%
DAY	$20.13	$32.00	58.9%	$20.94	$33.82	61.5%
DUKE	$19.38	$31.32	61.7%	$20.15	$33.16	64.6%
DOM	$19.31	$32.07	66.0%	$20.14	$33.97	68.7%
DPL	$17.30	$29.82	72.4%	$18.17	$32.34	78.0%
DUQ	$19.49	$28.94	48.5%	$20.21	$30.20	49.5%
EKPC	$19.10	$29.90	56.6%	$20.09	$32.27	60.6%
JCPLC	$17.16	$25.76	50.1%	$17.85	$27.27	52.8%
MEC	$17.50	$27.67	58.1%	$18.19	$29.15	60.3%
OVEC	$18.80	$29.01	54.3%	$19.52	$31.43	61.0%
PECO	$16.67	$25.24	51.4%	$17.24	$26.56	54.1%
PE	$18.31	$28.11	53.5%	$19.05	$29.45	54.6%
PEPCO	$19.66	$31.90	62.2%	$20.65	$33.87	64.0%
PPL	$16.70	$26.28	57.3%	$17.26	$27.45	59.1%
PSEG	$17.18	$26.99	57.1%	$17.75	$28.57	60.9%
REC	$17.52	$29.18	66.5%	$18.32	$32.25	76.1%
PJM	$18.55	$29.46	58.8%	$19.23	$31.00	61.2%

Figure 3-40 is a map of the real-time, load-weighted, average LMP in the first six 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 3-40 Real-time, load-weighted, average LMP: January through June, 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 3-49 shows the frequency and average shadow price of transmission constraints in PJM. In the first six months of 2021, there were 82,911 transmission constraint intervals in the real-time market with a nonzero shadow price. For nearly seven percent of these transmission constraint intervals, the line limit was violated, meaning that the flow exceeded the facility limit.[68] In the first six months of 2021, the average shadow price of transmission constraints when the line limit was violated was nearly 12.0 times higher than when the transmission constraint was binding at its limit.

Table 3-49 Frequency and average shadow price of transmission constraints: January through June, 2020 and 2021

	Frequency (Constraint Intervals)		Average Shadow Price	
Description	2020 (Jan - Jun)	2021 (Jan - Jun)	2020 (Jan - Jun)	2021 (Jan - Jun)
PJM Internal Violated Transmission Constraints	1,289	5,783	$1,745.42	$1,911.65
PJM Internal Binding Transmission Constraints	64,364	51,901	$63.68	$158.99
Market to Market Transmission Constraints	17,595	25,227	$238.31	$394.94
All Transmission Constraints	83,248	82,911	$126.63	$353.03

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 3-50 shows the frequency of changes to the transmission constraints for binding and violated transmission constraints in the PJM real-time market. In the first six months of 2021, there were 5,597 or 97 percent of 5,783 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 six months of 2021, among the constraints with reduced constraint limits, the constraint limit was reduced on average by 7.1 percent.

68 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 3-50 Frequency of reduction in line ratings (constraint intervals): January through June, 2020 and 2021

	Frequency (Constraint Intervals)		Constraints with Reduced Line Limits (Constraint Intervals)		Average Reduction (Percentage)	
Description	2020 (Jan - Jun)	2021 (Jan - Jun)	2020 (Jan - Jun)	2021 (Jan - Jun)	2020 (Jan - Jun)	2021 (Jan - Jun)
PJM Internal Violated Transmission Constraints	1,289	5,783	1,185	5,597	14.8%	6.6%
PJM Internal Binding Transmission Constraints	64,364	51,901	63,278	51,259	10.7%	7.5%
Market to Market Transmission Constraints	17,595	25,227	3,751	11,429	7.1%	5.6%
All Transmission Constraints	83,248	82,911	68,214	68,285	10.6%	7.1%

Table 3-51 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 six months of 2021, there were 5,161 or 89 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 3-51 Frequency of changes to the magnitude of transmission penalty factor (constraint intervals): January through June, 2020 and 2021

	2020 (Jan - Jun)			2021 (Jan - Jun)		
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	1,085	-	204	5,161	182	440
PJM Internal Binding Transmission Constraints	59,378	-	4,986	51,070	26	805
Market to Market Transmission Constraints	1,430	-	16,165	3,176	-	22,051
All Transmission Constraints	61,893	-	21,355	59,407	208	23,296

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 uses CT pricing logic to force otherwise uneconomic resources to be marginal and set price in the day-ahead and real-time market solutions. In the event PJM commits a resource that is uneconomic and/or offered with inflexible parameters, PJM uses 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.[69] Frequently, PJM dispatchers also manually override 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 3-52 shows the frequency of CT pricing logic used in the PJM Real-Time Energy Market. In the first six months of 2021, there were 6,421 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 is inconsistent with the efficient market dispatch and pricing. For that reason, in 2019 FERC declared CT pricing logic to be unjust and unreasonable.[70] PJM should discontinue the use of CT pricing logic, regardless of whether the new fast-start pricing process is in place.

69 PJM dispatchers generally log the resources paired with a constraint in the CT pricing logic. The data presented is based on PJM dispatcher logs.
70 167 FERC ¶ 61,058 at P 69 (2019).

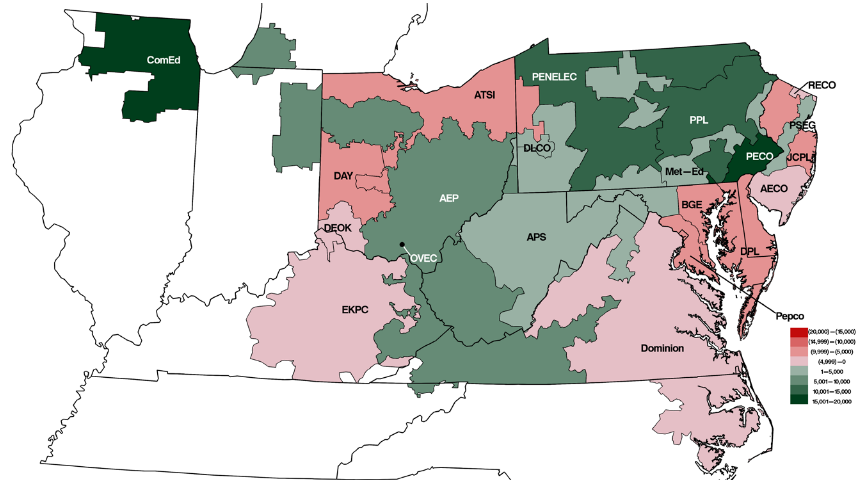
Table 3-52 Frequency of CT pricing logic used in the real-time market (constraint intervals): January 2020 through June 2021

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	-
Aug	1,189	-
Sep	1,982	-
Oct	2,017	-
Nov	956	-
Dec	1,404	-
Total	10,540	6,421

Net Generation by Zone

Figure 3-41 shows the difference between the PJM real-time generation and real-time load by zone in the first six months of 2021. Figure 3-41 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 3-53 shows the difference between the PJM real-time generation and real-time load by zone in the first six months of 2020 and 2021.

Figure 3-41 Map of real-time generation, less real-time load, by zone: January through June, 2021[71]



71 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 3-53 Real-time generation less real-time load by zone (GWh): January through June, 2020 and 2021

Zonal Generation and Load (GWh)						
Jan-Jun	2020			2021		
Zone	Generation	Load	Net	Generation	Load	Net
ACEC	1,647.5	4,184.7	(2,537.2)	1,061.6	4,473.6	(3,412.0)
AEP	66,795.0	58,633.4	8,161.6	69,916.7	61,567.8	8,348.8
APS	22,273.9	22,972.4	(698.6)	26,435.1	23,953.6	2,481.4
ATSI	20,277.9	30,114.8	(9,836.8)	23,828.9	31,403.2	(7,574.3)
BGE	7,529.4	14,029.0	(6,499.6)	8,723.6	14,756.3	(6,032.7)
COMED	62,501.6	43,419.8	19,081.7	63,646.5	44,533.0	19,113.6
DAY	333.0	7,855.2	(7,522.2)	537.0	8,240.7	(7,703.7)
DUKE	8,129.8	12,180.4	(4,050.6)	7,949.5	12,694.8	(4,745.3)
DOM	52,076.6	46,527.4	5,549.2	48,432.0	51,327.3	(2,895.3)
DPL	2,222.6	8,314.2	(6,091.6)	1,706.3	8,869.4	(7,163.1)
DUQ	7,511.6	6,095.9	1,415.7	8,003.4	6,300.9	1,702.5
EKPC	3,405.3	6,037.1	(2,631.8)	5,223.6	6,493.1	(1,269.5)
JCPLC	3,706.6	9,813.1	(6,106.5)	2,494.6	10,352.9	(7,858.3)
MEC	10,300.9	7,188.1	3,112.7	8,752.9	7,561.2	1,191.7
OVEC	3,931.6	57.9	3,873.8	5,201.9	58.5	5,143.4
PECO	36,855.0	17,642.7	19,212.3	35,169.8	18,510.7	16,659.1
PE	17,808.6	8,063.9	9,744.7	22,205.5	8,260.9	13,944.5
PEPCO	5,291.3	12,832.9	(7,541.6)	6,060.3	13,397.6	(7,337.3)
PPL	27,329.1	19,152.1	8,177.0	32,620.2	19,976.2	12,644.0
PSEG	20,195.4	19,096.2	1,099.1	20,708.5	19,921.4	787.2
RECO	0.0	631.1	(631.1)	0.0	663.5	(663.5)

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 3-54 shows PJM generation by fuel source in GWh for the first six months of 2020 and 2021. In the first six months of 2021, generation from coal units increased 39.7 percent, generation from natural gas units decreased 4.6 percent, and generation from oil increased 22.1 percent compared to the first six months of 2020. Wind and solar output rose by 12.8 percent compared to the first six months of 2020, supplying 4.6 percent of PJM energy in the first six months of 2021.

Table 3-54 Generation (By fuel source (GWh)): January through June, 2020 and 2021[72 73 74]

	2020 Jan - Jun		2021 Jan - Jun		Change in
	GWh	Percent	GWh	Percent	Output
Coal	67,844.9	17.6%	94,782.2	23.5%	39.7%
Bituminous	62,576.2	16.2%	84,715.1	21.0%	35.4%
Sub Bituminous	2,840.9	0.7%	7,161.9	1.8%	152.1%
Other Coal	2,427.8	0.6%	2,905.2	0.7%	19.7%
Nuclear	136,376.3	35.4%	133,383.6	33.0%	(2.2%)
Gas	151,835.5	39.4%	144,803.0	35.9%	(4.6%)
Natural Gas CC	143,212.5	37.2%	135,757.2	33.6%	(5.2%)
Natural Gas CT	5,588.7	1.5%	6,695.6	1.7%	19.8%
Natural Gas Other Units	1,981.6	0.5%	1,455.9	0.4%	(26.5%)
Other Gas	1,052.7	0.3%	894.3	0.2%	(15.0%)
Hydroelectric	9,155.7	2.4%	8,391.0	2.1%	(8.4%)
Pumped Storage	2,221.4	0.6%	2,205.8	0.5%	(0.7%)
Run of River	6,296.9	1.6%	5,613.2	1.4%	(10.9%)
Other Hydro	637.4	0.2%	572.0	0.1%	(10.3%)
Wind	14,497.6	3.8%	15,281.3	3.8%	5.4%
Waste	2,145.3	0.6%	2,241.1	0.6%	4.5%
Oil	931.5	0.2%	1,137.2	0.3%	22.1%
Heavy Oil	0.0	0.0%	0.3	0.0%	NA
Light Oil	55.2	0.0%	319.9	0.1%	479.9%
Diesel	9.5	0.0%	13.2	0.0%	38.7%
Other Oil	866.8	0.2%	803.7	0.2%	(7.3%)
Solar, Net Energy Metering	1,872.7	0.5%	3,183.5	0.8%	70.0%
Battery	17.1	0.0%	19.9	0.0%	16.6%
Biofuel	438.3	0.1%	565.9	0.1%	29.1%
Total	385,115.0	100.0%	403,788.6	100.0%	4.8%

Table 3-55 Monthly generation (By fuel source (GWh)): January through June, 2021

	Jan	Feb	Mar	Apr	May	Jun	Total
Coal	17,819.0	21,469.5	13,310.1	11,172.7	12,362.1	18,648.7	94,782.2
Bituminous	16,369.6	18,774.2	12,427.5	10,305.2	10,666.7	16,171.8	84,715.1
Sub Bituminous	901.4	2,124.5	312.7	610.2	1,239.6	1,973.5	7,161.9
Other Coal	548.0	570.7	570.0	257.3	455.9	503.4	2,905.2
Nuclear	25,133.4	22,125.3	21,217.1	19,692.2	21,841.2	23,374.4	133,383.6
Gas	26,011.3	22,670.8	23,925.8	21,904.3	22,545.8	27,745.0	144,803.0
Natural Gas CC	25,125.8	21,754.8	23,076.4	20,077.2	20,964.3	24,758.6	135,757.2
Natural Gas CT	616.1	579.9	569.5	1,465.1	1,131.2	2,333.8	6,695.6
Natural Gas Other Units	108.9	198.0	120.1	221.1	296.3	511.5	1,455.9
Other Gas	160.6	138.1	159.8	140.8	154.0	141.0	894.3
Hydroelectric	1,481.8	1,299.8	1,682.6	1,317.5	1,295.9	1,313.5	8,391.0
Pumped Storage	398.4	354.0	311.9	244.7	357.1	539.8	2,205.8
Run of River	994.9	847.5	1,282.8	1,004.4	865.0	618.6	5,613.2
Other Hydro	88.5	98.3	87.9	68.4	73.8	155.1	572.0
Wind	2,507.3	2,618.9	3,445.2	2,746.0	2,187.5	1,776.5	15,281.3
Waste	386.1	316.6	391.6	369.1	389.6	388.0	2,241.1
Oil	159.7	254.1	151.5	166.4	205.6	200.0	1,137.2
Heavy Oil	0.0	0.0	0.3	0.0	0.0	0.0	0.3
Light Oil	7.0	136.5	23.2	12.2	51.2	89.9	319.9
Diesel	1.4	2.8	1.2	3.6	0.2	4.0	13.2
Other Oil	151.4	114.8	126.8	150.6	154.1	106.1	803.7
Solar, Net Energy Metering	283.1	255.8	532.7	649.8	737.6	724.6	3,183.5
Battery	2.7	3.3	3.2	4.0	3.7	3.0	19.9
Biofuel	97.4	81.4	63.7	72.1	131.6	119.6	565.9
Total	73,881.8	71,095.4	64,723.4	58,094.1	61,700.6	74,293.3	403,788.6

72 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.

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

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

Table 3-56 Share of generation by fuel source: January 2008 through June 2021

Jan - Jun	Natural Gas	Coal	Nuclear	Other Fuel Type
2008	6.1%	56.0%	34.5%	3.4%
2009	9.1%	51.1%	36.1%	3.8%
2010	9.0%	50.9%	35.6%	4.5%
2011	12.8%	47.5%	34.9%	4.8%
2012	19.4%	40.3%	35.3%	5.0%
2013	16.0%	44.1%	35.1%	4.8%
2014	16.1%	45.8%	33.1%	5.0%
2015	21.0%	38.9%	34.6%	5.5%
2016	25.4%	32.2%	36.4%	6.0%
2017	24.8%	32.4%	36.2%	6.6%
2018	28.2%	29.7%	35.0%	7.1%
2019	33.5%	24.8%	34.4%	7.3%
2020	39.2%	17.6%	35.4%	7.8%
2021	35.6%	23.5%	33.0%	7.9%

Fuel Diversity

Figure 3-42 shows the fuel diversity index (FDI_e) for PJM energy generation.[75] 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 3-55 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 33.1 percent from 2012 through June 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.[76] 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 56.0 percent for for the first six months of 2008 and 23.5 percent for the first six months of 2021. Natural gas generation as a share of total generation was 6.1 percent for for the first six months of 2008 and 35.6 percent for the first six months of 2021. Wind generation as a share of total generation was 0.5 percent for for the first six months of 2008 and 3.8 percent for the first six months of 2021.

The FDI_e increased 2.8 percent for the first six months of 2021 compared to first six months of 2020. The increase in FDI_e is primarily due to an increase in coal generation in the first six months of 2021 compared to the first six 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.[77] Generation owners that intend to retire a generator are required by the tariff to notify PJM at least 90 days in advance.[78] There are 10,161.0 MW of generation that have requested retirement after June 30, 2021.[79] The at risk units and other generators with deactivation notices generated 25,631.1 GWh in the first six months of 2021. The dashed line in Figure 3-42 shows a counterfactual result for FDI_e assuming the 25,631.1 GWh of generation from at risk units and other generators with deactivation notices were replaced by gas, wind and solar generation.[80] The FDI_e for the first six months of 2021 under the counterfactual assumption would have been 0.9 percent lower than the actual FDI_e.

75 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.

76 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.

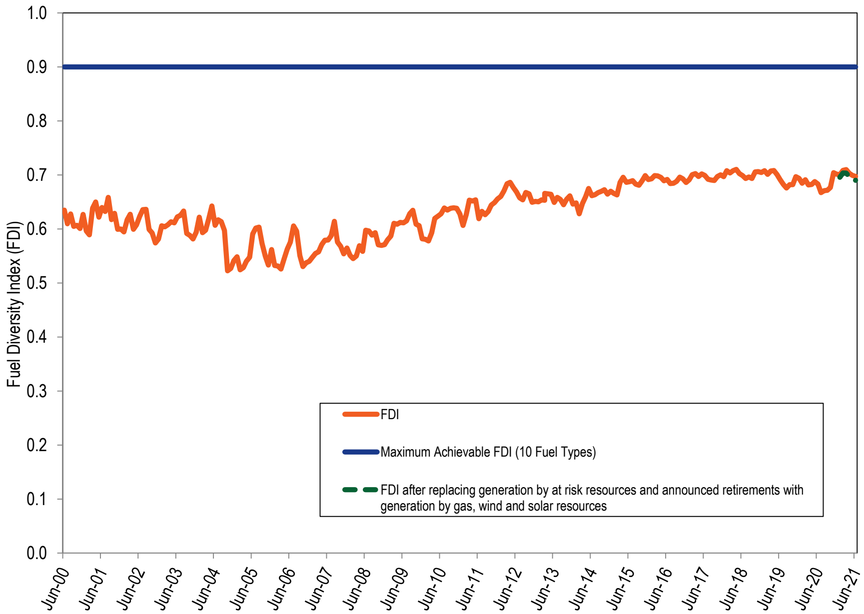
77 See Table 7-47 in the *2020 State of the Market Report for PJM*, Volume 2, Section 7: Net Revenue.

78 See PJM. OATT: § V "Generation Deactivation."

79 See *2021 State of the Market Report for PJM: January through June*, Section 12: Generation and Transmission Planning, Table 12-11.

80 It is assumed that 3,561.2 GWh of the replacement energy is from new wind and solar units. This value represents the increase over 2021 levels in renewable generation through June 30, 2021 that is required by RPS in the first six months of 2022. The split between solar and wind, 874.0 GWh solar and 2,687.2 GWh wind, is based on queue data.

Figure 3-42 Fuel diversity index for monthly generation: June 2000 through June 2021



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 six 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 3-57 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 six months of 2021, coal units were 16.8 percent and natural gas units were 68.7 percent of marginal resources. In the first six months of 2021, natural gas combined cycle units were 61.1 percent of marginal resources. In the first six months of 2020, coal units were 16.4 percent and natural gas units were 74.3 percent of the total marginal resources. In the first six months of 2020, natural gas combined cycle units were 70.1 percent of the total marginal resources. In the first six months of 2021, 87.1 percent of the wind marginal units had negative offer prices, 12.2 percent had zero offer prices and 0.7 percent of the wind marginal units had positive offer prices. In the first six months of 2020, 95.8 percent of the wind marginal units had negative offer prices, 4.2 percent had zero offer prices and none had positive offer prices.

The proportion of marginal nuclear units decreased from 1.29 percent in the first six months of 2020 to 0.80 percent in the first six 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.

Table 3-57 Type of fuel used and technology (By real-time marginal units): January through June, 2017 through 2021[81]

		(Jan - Jun)				
Fuel	Technology	2017	2018	2019	2020	2021
Gas	CC	44.11%	53.21%	63.09%	70.12%	61.12%
Coal	Steam	33.47%	29.65%	26.57%	16.41%	16.81%
Wind	Wind	9.81%	3.71%	3.47%	7.36%	11.59%
Gas	CT	3.78%	5.85%	4.19%	2.90%	6.50%
Other	Solar	0.15%	0.11%	0.07%	0.51%	1.31%
Uranium	Steam	0.96%	1.12%	0.67%	1.29%	0.80%
Gas	Steam	2.56%	1.34%	0.77%	0.99%	0.76%
Oil	CT	4.24%	3.19%	0.43%	0.05%	0.49%
Gas	RICE	0.30%	0.52%	0.00%	0.25%	0.30%
Other	Steam	0.16%	0.23%	0.07%	0.06%	0.13%
Oil	Steam	0.01%	0.55%	0.01%	0.01%	0.07%
Oil	RICE	0.37%	0.14%	0.00%	0.02%	0.06%
Oil	CC	0.00%	0.25%	0.03%	0.00%	0.04%
Municipal Waste	Steam	0.01%	0.05%	0.03%	0.01%	0.01%
Landfill Gas	CT	0.00%	0.00%	0.01%	0.01%	0.01%
Municipal Waste	RICE	0.00%	0.05%	0.00%	0.00%	0.00%
Municipal Waste	CT	0.00%	0.03%	0.00%	0.00%	0.00%
Landfill Gas	Steam	0.02%	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%

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

Figure 3-43 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 3-43 Type of fuel used (By real-time marginal units): January through June, 2004 through 2021

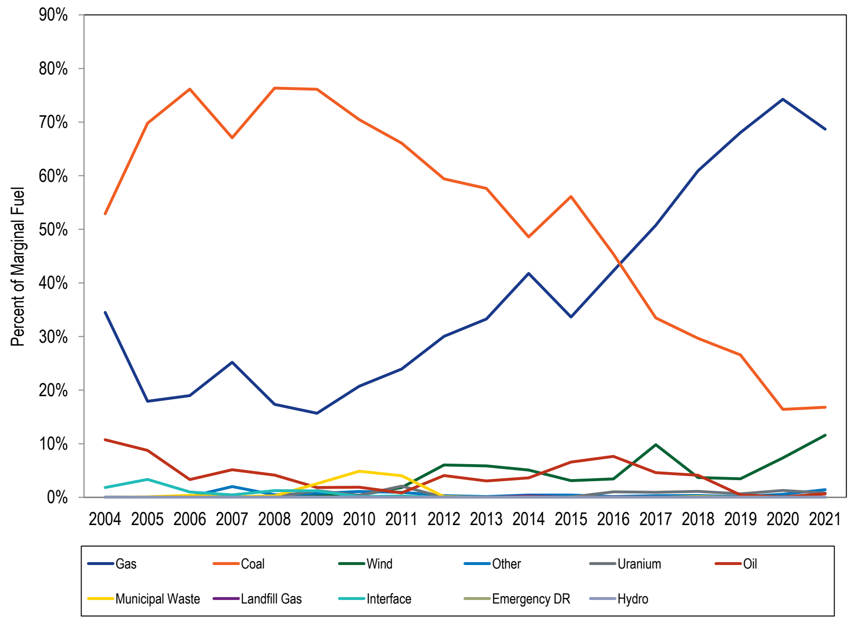


Table 3-58 shows the type of fuel used and technology where relevant, of marginal resources in the day-ahead energy market. In the first six months of 2021, up to congestion transactions were 36.5 percent of marginal resources. Up to congestion transactions were 52.3 percent of marginal resources in the first six months of 2020. In the first six months of 2021, virtual transactions were 79.3 percent of marginal resources. Virtual transactions were 80.8 percent of marginal resources in the first six months of 2020.

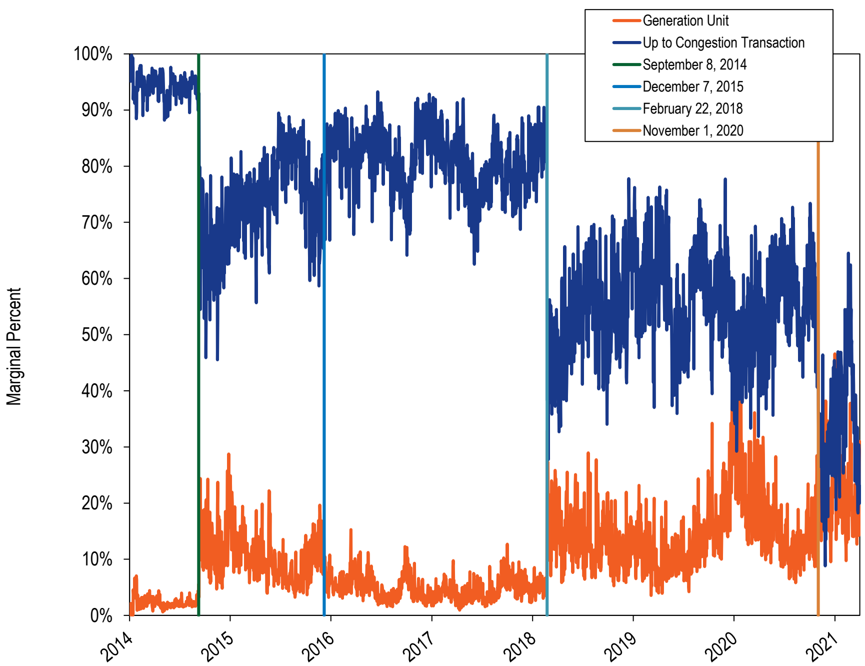
Table 3-58 Day-ahead marginal resources by type/fuel used and technology: January through June, 2017 through 2021

		(Jan - Jun)				
Type/Fuel	Technology	2017	2018	2019	2020	2021
Up to Congestion Transaction	NA	80.59%	66.89%	57.80%	52.29%	36.46%
DEC	NA	9.63%	14.65%	18.22%	14.21%	25.10%
INC	NA	5.33%	8.38%	13.33%	14.26%	17.75%
Gas	CC	1.94%	4.91%	5.80%	12.66%	11.90%
Coal	Steam	1.61%	4.15%	4.19%	5.32%	6.82%
Wind	Wind	0.23%	0.18%	0.11%	0.40%	0.94%
Gas	Steam	0.32%	0.26%	0.26%	0.31%	0.38%
Dispatchable Transaction	NA	0.03%	0.11%	0.11%	0.07%	0.20%
Gas	CT	0.04%	0.17%	0.07%	0.08%	0.13%
Gas	RICE	0.02%	0.04%	0.04%	0.02%	0.07%
Price Sensitive Demand	NA	0.00%	0.01%	0.00%	0.00%	0.05%
Other	Steam	0.00%	0.01%	0.01%	0.09%	0.04%
Municipal Waste	RICE	0.00%	0.00%	0.01%	0.01%	0.04%
Other	Solar	0.00%	0.03%	0.01%	0.02%	0.04%
Uranium	Steam	0.03%	0.08%	0.02%	0.23%	0.04%
Oil	Steam	0.00%	0.05%	0.00%	0.00%	0.02%
Oil	CT	0.21%	0.04%	0.01%	0.03%	0.01%
Oil	RICE	0.02%	0.00%	0.00%	0.00%	0.01%
Oil	CC	0.00%	0.03%	0.00%	0.00%	0.01%
Water	Hydro	0.00%	0.00%	0.00%	0.00%	0.00%
Total		100.00%	100.00%	100.00%	100.00%	100.00%

Figure 3-44 shows, for the day-ahead energy market from January 2014 through June 2021, the daily proportion of marginal resources that were up to congestion transactions and/or generation units. The UTC share decreased from 52.3 percent in the first six months of 2020 to 36.5 percent in the first six months of 2021.

Up to congestion transaction volumes decreased following the allocation of uplift charges on November 1, 2020.[82]

Figure 3-44 Day-ahead marginal up to congestion transaction and generation units: January 2014 through June 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 3-45 shows fuel prices in PJM for 2012 through June 2021. Natural gas prices increased in the first six months of 2021 compared to the first six months of 2020, as a result of very high gas prices in mid February. 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 six months of 2021, the price of production gas was 55.8 percent higher than in the first six months of 2020, the price of eastern natural gas was 77.2 percent higher and the price of western natural gas was 168.1 percent higher. The price of Northern Appalachian coal was 10.4 percent higher; the price of Central Appalachian coal was 32.8 percent higher; and the price of Powder River Basin coal was 1.2 percent lower.[83] The price of ULSD NY Harbor Barge was 78.6 percent higher.

82 172 FERC ¶ 61,046 (2020).

83 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.

Figure 3-45 Spot average fuel price comparison: 2012 through June 2021[84] ($/MMBtu)

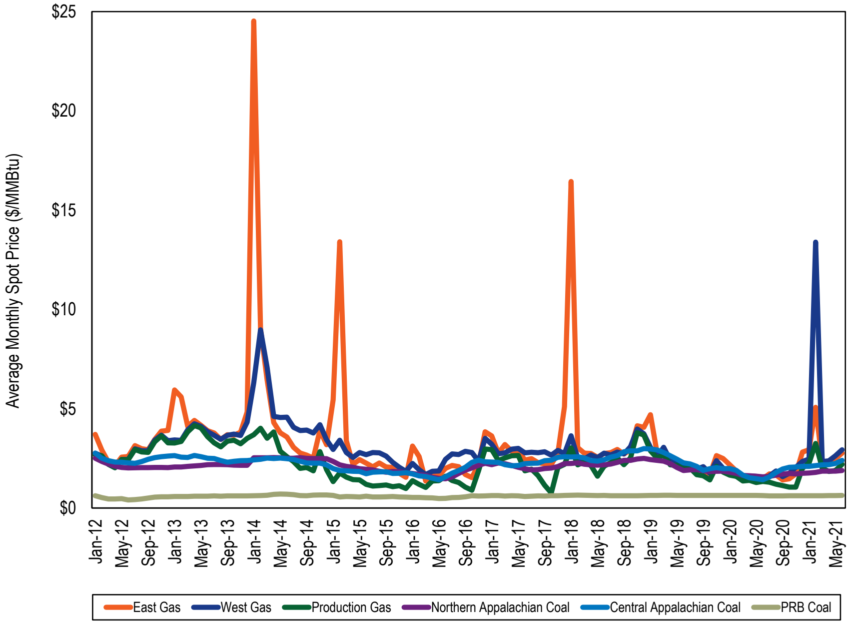


Table 3-59 compares the PJM real-time fuel-cost adjusted, load-weighted, average LMP in the first six months of 2021 to the load-weighted, average LMP in the first six months of 2020.[85] The real-time, load-weighted average LMP in the first six months of 2021 increased by $11.22 or 57.8 percent from the real-time load-weighted, average LMP in the first six months of 2020. The real-time load-weighted, average LMP for the first six months of 2021 was 50.6 percent higher than the real-time, fuel-cost adjusted, load-weighted average LMP for the first six months of 2021. The real-time, fuel-cost adjusted, load-weighted, average LMP for the first six months of 2021 was 4.8 percent higher than the real-time, load-weighted, average LMP for the first six months of 2020. If fuel and emissions costs in the first six months of 2021 had been the same as in the first six months of 2020, holding the market dispatch constant, the real-time, load-weighted, average LMP in the first six months of 2021 would have been lower, $20.33 per MWh, than the observed $30.62 per MWh. Almost all, 91.7 percent of the increase in real-time, load-weighted, average LMP, $10.29 per MWh out of $11.22 per MWh, is directly attributable to fuel costs. Contributors to the other $0.93 per MWh are increased load, adjusted dispatch, including adjustments to dispatch due to changes in relative fuel costs among units, and lower markups.

84 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.

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

Table 3-59 Real-time, fuel-cost adjusted, load-weighted average LMP (Dollars per MWh): January through June, 2020 and 2021

	2021 Fuel-Cost Adjusted, Load-Weighted LMP	2021 Load-Weighted LMP	Change	Percent Change
Average	$20.33	$30.62	$10.29	50.6%
	2020 Load-Weighted LMP	2021 Fuel-Cost Adjusted, Load-Weighted LMP	Change	Percent Change
Average	$19.40	$20.33	$0.93	4.8%
	2020 Load-Weighted LMP	2021 Load-Weighted LMP	Change	Change
Average	$19.40	$30.62	$11.22	57.8%

Table 3-60 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 six months of 2021. Table 3-60 shows that lower natural gas prices explain 89.7 percent of the fuel-cost related decrease in the real-time annual, load-weighted, average LMP in the first six months of 2021 from 2020.

Table 3-60 Share of change in fuel-cost adjusted LMP ($/MWh) by fuel type: January through June, 2021 adjusted to 2020 fuel prices

Fuel Type	Share of Change in Fuel Cost Adjusted, Load Weighted LMP	Percent
Gas	$9.23	89.7%
Coal	$0.98	9.5%
Oil	$0.08	0.8%
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	$10.29	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.[86] 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.

The components of LMP are shown in Table 3-61, including markup using unadjusted cost-based offers.[87] Table 3-61 shows that in the first six months of 2021, 14.0 percent of the load-weighted LMP was the result of coal costs, 51.7 percent was the result of gas costs and 2.7 percent was the result of the cost of carbon emission allowances. Using unadjusted cost-based offers, negative markup was -6.3 percent of the load-weighted LMP. Using unadjusted cost-based offers, positive markup was 5.9 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 six months of 2021, 11.2 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 six months of 2021 and 2020.

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

87 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 3-61 Components of real-time (Unadjusted), load-weighted, average LMP: January through June, 2020 and 2021

	2020 (Jan - Jun)		2021 (Jan - Jun)		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change in Percent
Gas	$7.94	40.9%	$15.83	51.7%	10.8%
Coal	$5.25	27.1%	$4.30	14.0%	(13.0%)
Constraint Violation Adder	$0.77	4.0%	$3.44	11.2%	7.3%
Ten Percent Adder	$1.58	8.2%	$2.04	6.6%	(1.5%)
Positive Markup	$1.85	9.5%	$1.81	5.9%	(3.6%)
Variable Maintenance	$1.44	7.4%	$1.15	3.8%	(3.7%)
NA	$0.53	2.7%	$0.83	2.7%	(0.0%)
Variable Operations	$0.83	4.3%	$0.83	2.7%	(1.6%)
CO_2 Cost	$0.36	1.8%	$0.82	2.7%	0.8%
LPA-SCED Differential	$0.01	0.1%	$0.72	2.3%	2.3%
Ancillary Service Redispatch Cost	$0.03	0.1%	$0.33	1.1%	0.9%
Scarcity Adder	$0.03	0.2%	$0.29	1.0%	0.8%
Oil	$0.03	0.1%	$0.28	0.9%	0.8%
NO_x Cost	$0.00	0.0%	$0.16	0.5%	0.5%
Opportunity Cost Adder	$0.02	0.1%	$0.07	0.2%	0.1%
Increase Generation Adder	$0.06	0.3%	$0.05	0.2%	(0.2%)
Landfill Gas	($0.01)	(0.1%)	$0.01	0.0%	0.1%
Market-to-Market Adder	$0.00	0.0%	$0.01	0.0%	0.0%
Other	$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	($0.01)	(0.0%)	$0.00	0.0%	0.0%
Decrease Generation Adder	($0.02)	(0.1%)	($0.02)	(0.1%)	0.0%
LPA Rounding Difference	$0.22	1.1%	($0.37)	(1.2%)	(2.3%)
Negative Markup	($1.50)	(7.7%)	($1.93)	(6.3%)	1.4%
Total	$19.40	100.0%	$30.62	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 3-61 and Table 3-64) markup is the difference between the price offer and the cost-based offer (unadjusted markup). In the second approach (Table 3-62 and Table 3-65), 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 3-62, including markup using adjusted cost-based offers.

Table 3-62 Components of real-time (Adjusted), load-weighted, average LMP: January through June, 2020 and 2021

	2020 (Jan - Jun)		2021 (Jan - Jun)		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change in Percent
Gas	$7.94	40.9%	$15.83	51.7%	10.8%
Coal	$5.25	27.1%	$4.30	14.0%	(13.0%)
Constraint Violation Adder	$0.77	4.0%	$3.44	11.2%	7.3%
Positive Markup	$2.70	13.9%	$2.84	9.3%	(4.7%)
Variable Maintenance	$1.44	7.4%	$1.15	3.8%	(3.7%)
NA	$0.53	2.7%	$0.83	2.7%	(0.0%)
Variable Operations	$0.83	4.3%	$0.83	2.7%	(1.6%)
CO_2 Cost	$0.36	1.8%	$0.82	2.7%	0.8%
LPA-SCED Differential	$0.01	0.1%	$0.72	2.3%	2.3%
Ancillary Service Redispatch Cost	$0.03	0.1%	$0.33	1.1%	0.9%
Scarcity Adder	$0.03	0.2%	$0.29	1.0%	0.8%
Oil	$0.03	0.1%	$0.28	0.9%	0.8%
NO_x Cost	$0.00	0.0%	$0.16	0.5%	0.5%
Opportunity Cost Adder	$0.02	0.1%	$0.07	0.2%	0.1%
Increase Generation Adder	$0.06	0.3%	$0.05	0.2%	(0.2%)
Landfill Gas	($0.01)	(0.1%)	$0.01	0.0%	0.1%
Market-to-Market Adder	$0.00	0.0%	$0.01	0.0%	0.0%
Other	$0.00	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	($0.01)	(0.0%)	$0.00	0.0%	0.0%
Decrease Generation Adder	($0.02)	(0.1%)	($0.02)	(0.1%)	0.0%
LPA Rounding Difference	$0.22	1.1%	($0.37)	(1.2%)	(2.3%)
Negative Markup	($0.78)	(4.0%)	($0.93)	(3.0%)	1.0%
Total	$19.40	100.0%	$30.62	100.0%	0.0%

Table 3-63 shows the components of the load weighted LMP, using unadjusted cost based offers, for the seven days between February 13, 2021, and February 18, 2021, when gas prices were high in the PJM region. Table 3-63 shows that in the seven days of 2021 with the highest gas prices, 1.9 percent of the load-weighted LMP was the result of coal costs, 66.3 percent was the result of gas costs and 13.6 percent was the result of transmission constraint penalty factors. The transmission constraints that were violated during this period included the high voltage constraints: AP South reactive transfer interface; Broadford 765 kV Transformer; Kyger Creek to Department of Energy, 345 kV transmission line; and Cedar substation to William, 230 kV transmission line. Negative markup was -7.5 percent of the load-weighted LMP.

Table 3-63 Components of real-time (Unadjusted), load-weighted, average LMP: February 13, 2021 through February 18, 2021

	13 February - 18 February	
	Contribution to LMP	Percent
Gas	$50.83	66.3%
Constraint Violation Adder	$10.42	13.6%
Positive Markup	$5.64	7.4%
Ten Percent Adder	$5.07	6.6%
Oil	$4.73	6.2%
Coal	$1.43	1.9%
Variable Maintenance	$1.09	1.4%
CO_2 Cost	$1.03	1.3%
Variable Operations	$0.62	0.8%
NA	$0.43	0.6%
Ancillary Service Redispatch Cost	$0.42	0.6%
LPA Rounding Difference	$0.27	0.3%
LPA-SCED Differential	$0.15	0.2%
Opportunity Cost Adder	$0.15	0.2%
Increase Generation Adder	$0.14	0.2%
Market-to-Market Adder	$0.03	0.0%
NO_x Cost	$0.00	0.0%
SO_2 Cost	$0.00	0.0%
Decrease Generation Adder	($0.03)	(0.0%)
Negative Markup	($5.72)	(7.5%)
Total	$76.61	100.0%

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, day-ahead scheduling reserve (DASR) adder and the 10 percent cost offer adder. INC offers, DEC bids and up to congestion transactions are dispatchable injections and withdrawals in the day-ahead energy market with an offer price that cannot be decomposed. Using identified marginal resource offers and the components of unit offers, it is possible to decompose PJM system LMP using the components of unit offers and sensitivity factors.

Table 3-64 shows the components of the PJM day-ahead, annual, load-weighted, average LMP. In the first six months of 2021, 27.7 percent of the load-weighted LMP was the result of gas costs, 14.3 percent of the load-weighted LMP was the result of coal costs, 28.3 percent was the result of DEC bid costs, 12.4 percent was the result of INC bid costs and 2.2 percent was the result of the up to congestion transaction costs.

Table 3-64 Components of day-ahead, (unadjusted), load-weighted, average LMP (Dollars per MWh): January through June, 2020 and 2021

	2020 (Jan - Jun)		2021 (Jan - Jun)		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change in Percent
DEC	$3.55	18.4%	$8.78	28.3%	9.9%
Gas	$3.63	18.9%	$8.59	27.7%	8.9%
Coal	$5.58	29.0%	$4.43	14.3%	(14.7%)
INC	$2.69	14.0%	$3.84	12.4%	(1.6%)
Ten Percent Cost Adder	$1.12	5.8%	$1.52	4.9%	(0.9%)
Variable Operating Cost	$0.74	3.9%	$0.72	2.3%	(1.5%)
Variable Maintenance Cost	$0.99	5.2%	$0.72	2.3%	(2.8%)
Up to Congestion Transaction	$0.62	3.2%	$0.67	2.2%	(1.1%)
CO_2	$0.21	1.1%	$0.67	2.2%	1.1%
Dispatchable Transaction	$0.09	0.5%	$0.42	1.4%	0.9%
Price Sensitive Demand	$0.00	0.0%	$0.23	0.7%	0.7%
Markup	($0.14)	(0.7%)	$0.22	0.7%	1.4%
NO_x	$0.01	0.0%	$0.14	0.5%	0.4%
Municipal Waste	($0.00)	(0.0%)	$0.10	0.3%	0.3%
Oil	($0.01)	(0.0%)	$0.06	0.2%	0.2%
Constrained Off	$0.07	0.4%	$0.02	0.0%	(0.3%)
DASR Offer Adder	$0.00	0.0%	$0.00	0.0%	0.0%
SO_2	$0.00	0.0%	$0.00	0.0%	(0.0%)
Other	$0.00	0.0%	$0.00	0.0%	(0.0%)
DASR LOC Adder	$0.01	0.0%	($0.02)	(0.1%)	(0.1%)
Wind	($0.00)	(0.0%)	($0.21)	(0.7%)	(0.7%)
Uranium	$0.00	0.0%	$0.00	0.0%	(0.0%)
NA	$0.07	0.4%	$0.10	0.3%	(0.0%)
Total	$19.23	100.0%	$31.00	100.0%	0.0%

Table 3-65 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 3-65 Components of day-ahead, (adjusted), load-weighted, average LMP (Dollars per MWh): January through June, 2020 and 2021

	2020 (Jan - Jun)		2021 (Jan - Jun)		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change in Percent
DEC	$3.55	18.4%	$8.78	28.3%	9.9%
Gas	$3.63	18.9%	$8.59	27.7%	8.9%
Coal	$5.58	29.0%	$4.43	14.3%	(14.7%)
INC	$2.69	14.0%	$3.84	12.4%	(1.6%)
Markup	$0.98	5.1%	$1.75	5.6%	0.5%
Variable Operating Cost	$0.74	3.9%	$0.72	2.3%	(1.5%)
Variable Maintenance Cost	$0.99	5.2%	$0.72	2.3%	(2.8%)
Up to Congestion Transaction	$0.62	3.2%	$0.67	2.2%	(1.1%)
CO_2	$0.21	1.1%	$0.67	2.2%	1.1%
Dispatchable Transaction	$0.09	0.5%	$0.42	1.4%	0.9%
Price Sensitive Demand	$0.00	0.0%	$0.23	0.7%	0.7%
NO_x	$0.01	0.0%	$0.14	0.5%	0.4%
Municipal Waste	($0.00)	(0.0%)	$0.10	0.3%	0.3%
Oil	($0.01)	(0.0%)	$0.06	0.2%	0.2%
Constrained Off	$0.07	0.4%	$0.02	0.0%	(0.3%)
DASR Offer Adder	$0.00	0.0%	$0.00	0.0%	0.0%
Ten Percent Cost Adder	($0.00)	(0.0%)	$0.00	0.0%	0.0%
SO_2	$0.00	0.0%	$0.00	0.0%	(0.0%)
Other	$0.00	0.0%	$0.00	0.0%	(0.0%)
DASR LOC Adder	$0.01	0.0%	($0.02)	(0.1%)	(0.1%)
Wind	($0.00)	(0.0%)	($0.21)	(0.7%)	(0.7%)
Uranium	$0.00	0.0%	$0.00	0.0%	(0.0%)
NA	$0.07	0.4%	$0.10	0.3%	(0.0%)
Total	$19.23	100.0%	$31.00	100.0%	0.0%

Shortage

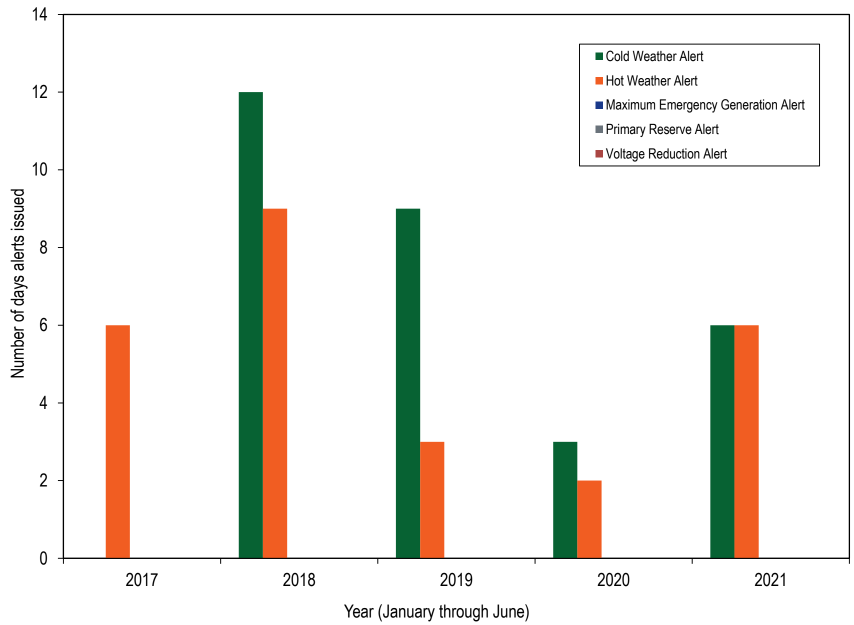
PJM's energy market experienced five minute shortage pricing for ten 5 minute intervals on seven days in the first six months of 2021. Table 3-66 shows a summary of the number of days emergency alerts, warnings and actions were declared in PJM in the first six months of 2020 and 2021. In the first six 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 3-66 Summary of emergency events declared: January through June, 2020 and 2021

	Number of days events declared	
Event Type	2020 (Jan - Jun)	2021 (Jan - Jun)
Cold Weather Alert	3	6
Hot Weather Alert	2	6
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	7
Energy export recalls from PJM capacity resources	0	0

Figure 3-46 shows the number of days that weather and capacity emergency alerts were issued in PJM in the first six months of 2017 through 2021.

Figure 3-46 Declared emergency alerts: January through June, 2017 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 3-67 provides a description of PJM declared emergency procedures.[88] [89] [90] [91]

Table 3-67 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.

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

Table 3-68 shows the dates when emergency alerts and warnings were declared and when emergency actions were implemented in the first six months of 2021.

Table 3-68 Declared emergency alerts, warnings and actions: January through June, 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												

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.[92] 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

92 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.

energy; a process for the recall of energy from capacity resources; and the minimum level of synchronized reserves that would trigger load shedding.The average energy component of LMP in that 5 minute interval (on March 22) with artificially increased supply to satisfy the power balance constraint was $3,685.20 per MWh.

Table 3-69 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 six months of 2021, there was one 5 minute interval using an RT SCED solution with a violated power balance constraint. The average energy component of LMP in that 5 minute interval (on March 22) with artificially increased supply to satisfy the power balance constraint was $3,685.20 per MWh.[93]

Table 3-69 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 - Jun)	1	$3,685.20

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 1.0 MW of demand response.[94] 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.[95] 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.[96] 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 ten and thirty minute nonspinning reserves.[97] Reserve shortages are determined based on a predefined reserve requirement, and the reserve calculation that is embedded in the real-time dispatch tool.

93 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.

94 See *2018 State of the Market Report for PJM*, Volume II, Section 3: Energy Market, at Scarcity, pp. 201 – 202.

95 *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?>.

96 OATT Definitions at "Emergency Action".

97 ISO New England Inc. Internal Market Monitor, "2018 Annual Markets Report," (May 23, 2019) at 156 (§ 6.2.2 (Pay-for-Performance Outcomes)).

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, Dominion and Pepco Zones based on anticipated high load relative to the available supply. The actual load was significantly lower than forecasted.[98]

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.[99] 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.[100] 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 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 six months of 2021, there were ten 5 minute intervals with shortage pricing that occurred on seven 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.[101] 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.

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.[102]

98 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>.

99 *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).

100 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.

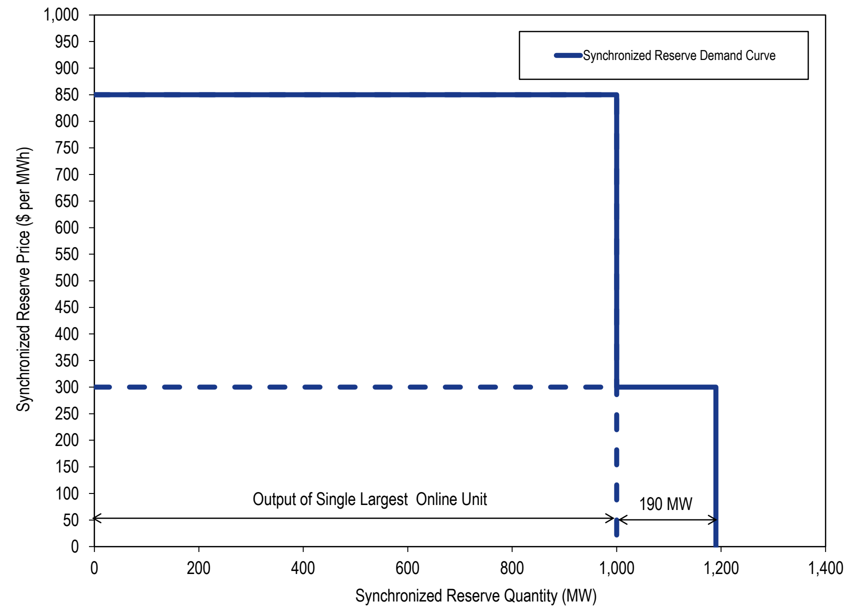
101 *Settlement Intervals and Shortage Pricing in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Order No. 825, 155 FERC ¶ 61,276 at P 162 (2016).

102 *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).

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 3-47 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.

Figure 3-47 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 3-47 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.[103] The $1,700 per MWh penalty applies any time PJM initiates a manual load dump action or voltage reduction action.[104]

Table 3-70 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 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.[105]

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.

103 *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.

104 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.

105 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.

Table 3-70 Additive penalty factors under reserve shortage and transmission constraint violations: Status Quo

		Synchronized Reserve Penalty Factor		Primary Reserve Penalty Factor			System Marginal Price			Total LMP	
Scenario	Marginal Unit Offer Price	RTO	MAD	RTO	MAD	Transmission Constraint Penalty Factor in SMP	MAD Marginal	RTO Marginal	Transmission Constraint Penalty Factor in CLMP	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.[106] 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 3-71 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 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.[107]

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.

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

107 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.

Table 3-71 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

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 May 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.[108] 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 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.

108 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>.

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.

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.[109] [110] On June 3, 2021, PJM updated RT SCED to solve two additional scenarios, or a total of five solutions per case. In the first six 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 3-72 shows, for each month of 2020 and the first six 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 3-72 shows that, in the first six months of 2021, 1,301 target times, or 2.5 percent of all five minute target times, had at least one RT SCED solution showing a shortage of reserves, and 333 target times, or 0.6 percent of all five minute target times, had more than one RT SCED solution showing a shortage of reserves. In the first six months of 2020, there were 874 target times, or 1.7 percent of all five minute target times, that had at least one RT SCED solution showing a shortage of reserves, and 364 target times, or 0.7 percent of all five minute target times, that had more than one RT SCED solution showing a shortage of reserves.

109 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.
110 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 3-72 Five minute SCED target times and pricing intervals with shortage: January 2020 through June 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%
2021 Total	52,116	1,301	2.5%	333	0.6%	10	0.8%

In the first six months of 2021, there were ten 5 minute intervals with shortage pricing, while there were 333 five minute target times for which multiple RT SCED solutions showed a shortage of reserves. In the first six months of 2020, there were two 5 minute intervals with shortage pricing, while 364 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 ten 5 minute intervals with shortage pricing in the first six months of 2021, compared to two intervals in the first six months of 2020, in PJM. Table 3-73 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 ten intervals with shortage pricing due to synchronized reserve shortage. Table 3-74 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 ten intervals with shortage pricing due to synchronized reserve shortage. Table 3-75 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 four intervals with shortage pricing due to primary reserve shortage. Table 3-76 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 three 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.[111] 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 ten intervals in the first six months of 2021 with shortage pricing, both the RTO Zone and the MAD Subzone cleared with synchronized reserves less than their extended requirement. In four out of the ten intervals, the synchronized reserves in the RTO Zone were short of the minimum reserve requirement, resulting in an $850 per MWh penalty factor. In six out of the ten 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.

111 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 3-73 RTO synchronized reserve shortage intervals: January through June, 2021

Interval (EPT)	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

Table 3-74 MAD synchronized reserve shortage intervals: January through June, 2021

Interval (EPT)	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

Table 3-75 RTO primary reserve shortage intervals: January through June, 2021

Interval (EPT)	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

Table 3-76 MAD primary reserve shortage intervals: January through June, 2021

Interval (EPT)	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

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.[112]

System Marginal Price Cap

In the PJM real time 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

112 OA Schedule 1, Section 3.2.3A(d) and Section 3.2.3A.001(c).

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 market.

Table 3-77 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 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 3-78 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.[113] The SMP, without the use of the capping logic, would have been at least $3,965.08 per MWh.[114]

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.

Table 3-77 Five minute intervals based on approved SCED cases that used SMP capping logic: January 2018 through June 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

113 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.

114 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 3-78 Components of SMP for five minute intervals based on approved SCED cases that used SMP capping logic: January 2018 through June 2021

		Components of Final SMP				
Five Minute Interval	Lower bound 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.[115]
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).[116] [117] 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.

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.

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

116 *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.

117 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).

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. 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.[118]

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 six 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 six months of 2021 was unconcentrated on average (Table 3-79).[119] 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 3-79 Hourly energy market HHI: January through June, 2020 and 2021

By offering supplier	Hourly Market HHI (Jan - Jun, 2020)	Hourly Market HHI (Jan - Jun, 2021)
Average	788	751
Minimum	567	574
Maximum	1126	1118
Highest market share (One hour)	28%	27%
Average of the highest hourly market share	20%	19%
# Hours	4,367	4,343
# Hours HHI > 1800	0	0
% Hours HHI > 1800	0%	0%

Table 3-80 includes HHI values by supply curve segment, including base, intermediate and peaking plants for the first six 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.[120] High concentration levels, particularly in the peaking segment, increase the probability that a generation owner will be pivotal in the aggregate market.

118 See *Inquiry Concerning the Commission's Merger Policy under the Federal Power Act: Policy Statement*, 77 FERC ¶ 61,263 *mimeo* at 80 (1996).

119 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.

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

Table 3-80 Generation segment HHI: January through June, 2020 and 2021

	2020 (Jan - Jun)			2021 (Jan - Jun)		
By offering supplier	Minimum	Average	Maximum	Minimum	Average	Maximum
Base	645	827	1181	634	799	1131
Intermediate	698	1791	9222	665	1384	9067
Peak	646	5798	10000	722	5727	10000

Figure 3-48 shows the total installed capacity (ICAP) MW of units in the baseload, intermediate and peaking segments by fuel source in the first six months of 2021.[121]

Figure 3-48 Fuel source distribution in unit segments: January through June, 2021[122]

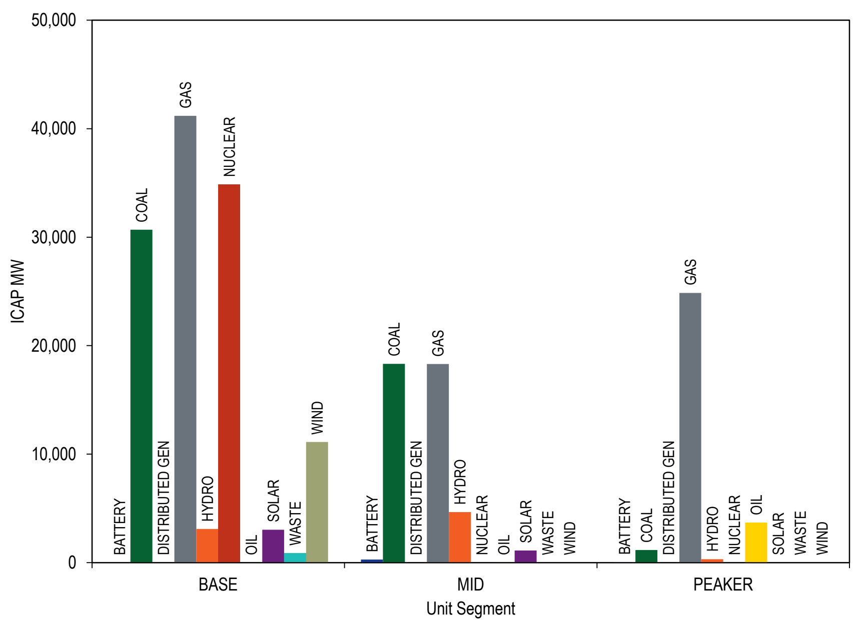
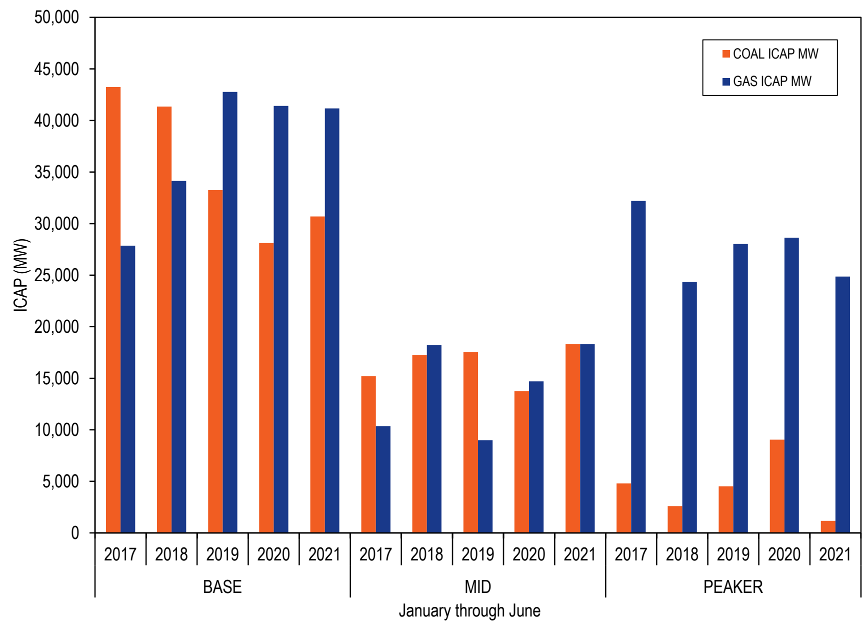


Figure 3-49 shows the ICAP of coal fired and gas fired units in PJM that are classified as baseload, intermediate and peaking in the first six months from 2017 through 2021. Figure 3-49 shows that the total ICAP of coal fired units in PJM classified as baseload generally decreased from 2017 through 2021, 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.

Figure 3-49 Unit segment classification by fuel: January through June, 2017 through 2021

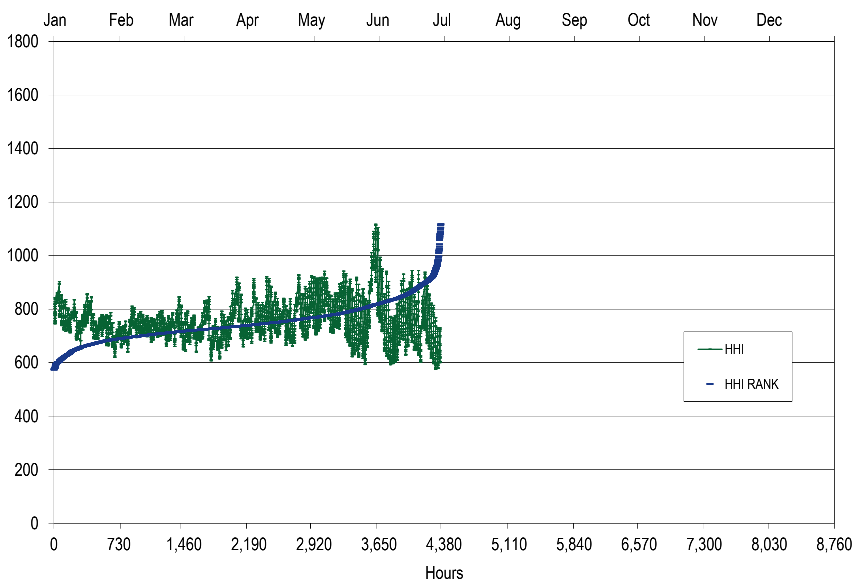


121 The installed capacity (ICAP) used for wind and solar units here is their nameplate capacity in MW. In PJM's Capacity Market, the ICAP value of wind and solar units is derated from the nameplate capacity to reflect their effective load carrying capability.

122 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 3-50 presents the hourly HHI values in chronological order and an HHI duration curve for the first six 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.

Figure 3-50 Hourly energy market HHI: January through June, 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 – 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 – 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.[123]

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).[124] 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.[125] 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.[126] [127]

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."[128]

123 *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").
124 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>.
125 See, e.g., Protest of the Independent Market Monitor for PJM, Docket No. ER10-1556 (August 28, 2020).
126 See 175 FERC ¶ 61,231 (June 17, 2021).
127 See 174 FERC ¶ 61,212 (March 18, 2021).
128 18 U.S.C. § 824b.

FERC applies tests set forth in the 1996 Merger Policy Statement.[129] [130]

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.[131]

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.[132] The MMU has proposed that FERC adopt this approach when evaluating mergers in PJM.[133] FERC has considered the MMU's analysis in reviewing mergers.[134]

129 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).

130 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.

131 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)

132 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).

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

134 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).

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 3-81 shows transactions that involved an entire generation unit or unit owner that were completed in the first six months of 2021, as reported to the Commission. Table 3-82 shows transactions that involved transfers of partial unit ownership that were completed in the first six months of 2021, as reported to the Commission.[135]

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

Table 3-81 Completed transfers of entire resources: January through June, 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

Table 3-82 Completed transfers of partial ownership of resources: January through June, 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

The MMU has also facilitated settlements for mitigation of market power, in cases where market power concerns have been identified.[136] 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.

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.[137] 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.[138] 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 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'

136 See 138 FERC ¶ 61,167 at P 19.

137 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).

138 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.

available economic capacity in the peak hour of the operating day in order to meet demand.

Figure 3-51 shows the number of days in 2020 and the first six 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 on February 15, 2021. Two suppliers were jointly pivotal on 128 days in 2020 and on 60 days in the first six months of 2021. Three suppliers were jointly pivotal on 301 days in 2020 and on 150 days in the first six months of 2021, despite average HHIs at persistently unconcentrated levels. In 2020, 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 3-51 Days with pivotal suppliers and numbers of pivotal suppliers in the day-ahead energy market by quarter

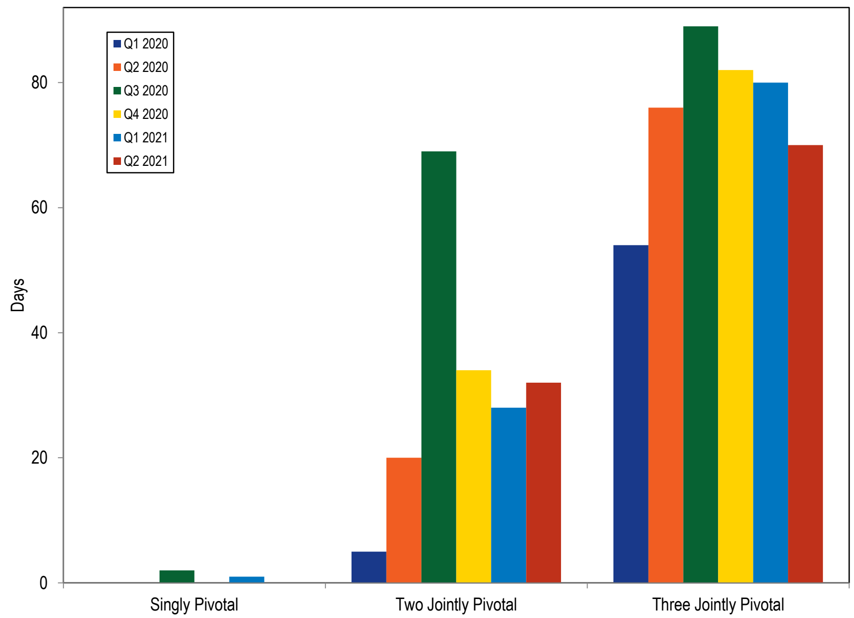


Table 3-83 provides the frequency with which each of the top 10 pivotal suppliers was singly or jointly pivotal for the day-ahead energy market in the first six months of 2021. The largest pivotal supplier was singly pivotal on one day in the first six months of 2021. All of the top 10 suppliers were one of two pivotal suppliers on at least seven days in the first six months of 2021. All of the top 10 suppliers were one of three pivotal suppliers on at least 88 days in the first six months of 2021.

Table 3-83 Day-ahead market pivotal supplier frequency: January through June, 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	1	0.6%	57	31.5%	150	82.9%
2	0	0.0%	56	30.9%	149	82.3%
3	0	0.0%	46	25.4%	150	82.9%
4	0	0.0%	32	17.7%	143	79.0%
5	0	0.0%	24	13.3%	134	74.0%
6	0	0.0%	12	6.6%	120	66.3%
7	0	0.0%	11	6.1%	105	58.0%
8	0	0.0%	9	5.0%	103	56.9%
9	0	0.0%	7	3.9%	94	51.9%
10	0	0.0%	7	3.9%	88	48.6%

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.[139] 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 six months of 2021, the 500 kV system, 12 zones, and MISO experienced congestion resulting from one or more constraints binding for 50 or more hours, or resulting from a binding interface constraint (Table 3-84).[140] Table 3-84 shows that the 500 kV system, three zones and MISO experienced congestion resulting from one or more constraints binding for 50 or more hours or resulting from a binding interface constraint in every year from January through June, 2009 through 2021. Three control zones did not experience congestion resulting from one or more constraints binding for 50 or more hours or resulting from any binding interface constraint in any year from January through June, 2009 through 2021.

Table 3-84 Congestion hours resulting from one or more constraints binding for 50 or more hours or from an interface constraint: January through June, 2009 through 2021

	(Jan - Jun)												
	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
500 kV System	2,026	2,861	2,650	369	720	1,370	722	700	341	458	1,216	1,767	1,116
ACEC	149	69	88	0	0	0	0	383	0	0	136	0	0
AEP	932	355	1,409	322	811	1,773	1,902	471	456	1,020	137	739	1,370
APS	198	410	52	113	51	170	451	79	0	81	0	333	111
ATSI	101	0	0	1	70	403	464	0	483	1,866	237	263	460
BGE	90	154	184	1,556	316	1,142	3,079	4,923	772	1,861	205	2,458	1,572
COMED	576	1,406	153	845	1,678	1,729	1,727	2,910	748	564	283	923	897
DAY	0	0	0	0	0	0	0	0	0	0	0	0	0
DLCO	156	342	0	209	0	281	747	0	0	57	0	0	0
DOM	310	589	659	200	0	52	1,422	759	80	136	0	584	498
DPL	0	0	0	126	142	560	1,199	1,399	326	295	0	0	144
DUKE	0	0	0	58	0	0	69	0	0	68	0	0	174
DUQ	0	0	0	0	0	0	0	0	0	0	0	0	0
EKPC	0	0	0	0	0	65	0	0	0	159	0	0	0
EXT	0	0	0	0	0	0	0	0	743	0	56	53	0
JCPLC	0	0	0	0	0	0	79	0	0	0	0	0	0
MEC	0	0	0	68	73	0	182	0	0	1,235	182	564	295
MISO	3,554	1,879	3,749	7,080	8,549	10,367	6,570	7,191	3,871	4,224	3,058	2,194	2,158
NYISO	0	0	0	0	167	121	149	1,374	332	0	0	0	0
OVEC	0	0	0	0	0	0	0	0	0	0	0	0	0
PE	55	0	0	0	0	1,441	1,385	551	1,537	1,127	1,009	1,940	52
PECO	59	0	130	53	256	944	485	732	852	130	187	0	0
PEPCO	0	0	59	203	85	39	0	0	0	0	0	0	0
PPL	176	0	52	146	188	147	0	0	741	177	682	836	921
PSEG	438	479	605	316	1,462	2,023	2,591	220	159	334	248	0	1,506
REC	0	0	0	0	0	0	0	0	0	0	0	0	0

139 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>.

140 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.

In the PJM Day-Ahead Energy Market, the TPS test is performed in PROBE, as part of the unit commitment process. Table 3-85 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.

Table 3-85 Day-ahead three pivotal supplier test details for interface constraints: January through June, 2021

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
BC Pepco	Peak	187	1,129	21	18	3
	Off Peak	1,061	1,189	15	0	15
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

Table 3-86 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 PJM Day-Ahead Energy Market, the TPS test evaluates each constraint that was binding for each hour during the operating day.

Table 3-86 Day-ahead three pivotal supplier test details for top 10 congested constraints: January through June, 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
Cedar Grove Sub - William	Peak	209	156	8	0	8
	Off Peak	167	72	7	0	7
Bagley - Raphael Road	Peak	322	421	22	6	17
	Off Peak	250	341	22	8	13
Nottingham	Peak	285	274	21	6	15
	Off Peak	167	218	19	8	11
East Lima - Haviland	Peak	103	148	11	1	10
	Off Peak	101	129	10	0	9
Three Mile Island	Peak	349	229	18	1	17
	Off Peak	242	172	15	1	14
Harwood - Susquehanna	Peak	120	189	10	1	9
	Off Peak	119	143	9	0	9
Face Rock	Peak	125	133	10	1	9
	Off Peak	74	97	8	0	8
Vienna	Peak	291	263	6	0	6
	Off Peak	327	285	5	0	5
Ramapo (ConEd) - S Mahwah (RECO)	Peak	21	2	2	0	2
	Off Peak	NA	NA	NA	NA	NA

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 2020.[141] While the real-time constraint hours include constraints that were binding in the five minute real-time pricing solution (LPC), 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. 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.

141 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>.

Table 3-87 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 3-88 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 3-87 and Table 3-88 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.

Table 3-87 Three pivotal supplier test details for interface constraints: January through June, 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	32	81	5	1	5
	Off Peak	14	154	5	1	4

Table 3-88 Three pivotal supplier test details for top 10 congested constraints: January through June, 2021

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
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
Brighton	Peak	187	330	19	10	8
	Off Peak	127	230	16	7	9
Northwest Tap - Purdue	Peak	35	50	2	0	2
	Off Peak	25	42	2	0	2
Nottingham	Peak	71	108	10	2	8
	Off Peak	51	84	9	1	7
East Lima - Haviland	Peak	27	32	1	0	1
	Off Peak	27	28	1	0	1
Harwood - Susquehanna	Peak	33	38	4	0	4
	Off Peak	20	30	3	0	3
North Coulterville	Peak	26	16	3	0	3
	Off Peak	18	13	2	0	2
Sandburg	Peak	25	12	3	0	3
	Off Peak	23	13	3	0	3
Bagley - Graceton	Peak	105	210	11	6	6
	Off Peak	81	150	10	4	6

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.[142] 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

142 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.

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 3-89 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 3-89 shows that 7.9 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 3-89 Day-ahead committed units that cleared real-time: January through June, 2020 and 2021

(Jan - Jun)	Day Ahead Price Based Unit Hours That Cleared Real-Time on Cost	Day Ahead Price Based Unit Hours That Cleared Real-Time on Price	Day Ahead Price Based Unit Hours That Failed Real-Time TPS and Cleared Real-Time on Price	Percent Day Ahead Price Based Unit Hours That Cleared Real-Time on Cost	Percent Day Ahead Price Based Unit Hours That Failed Real-Time TPS and Cleared Real-Time on Price
2020	3,528	1,233,994	80,764	0.3%	6.5%
2021	11,404	1,284,844	102,382	0.9%	7.9%

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 3-90 and Table 3-91 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.

Table 3-90 Summary of three pivotal supplier tests applied for interface constraints: January through June, 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	104	102	98%	4	4%	4%
	Off Peak	205	177	86%	3	1%	2%

Table 3-91 Summary of three pivotal supplier tests applied for top 10 congested constraints: January through June, 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
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	6,282	5,353	85%	55	1%	1%
Brighton	Peak	8,137	8,134	100%	279	3%	3%
	Off Peak	8,053	8,053	100%	113	1%	1%
Northwest Tap - Purdue	Peak	11,943	1,503	13%	0	0%	0%
	Off Peak	6,444	591	9%	0	0%	0%
Nottingham	Peak	8,060	7,877	98%	62	1%	1%
	Off Peak	5,211	5,034	97%	43	1%	1%
East Lima - Haviland	Peak	4,868	34	1%	0	0%	0%
	Off Peak	4,861	18	0%	0	0%	0%
Harwood - Susquehanna	Peak	3,663	2,863	78%	17	0%	1%
	Off Peak	2,183	1,384	63%	3	0%	0%
North Coulterville	Peak	140	2	1%	0	0%	0%
	Off Peak	1,177	54	5%	0	0%	0%
Sandburg	Peak	2,665	263	10%	0	0%	0%
	Off Peak	2,658	427	16%	8	0%	2%
Bagley - Graceton	Peak	5,178	5,107	99%	33	1%	1%
	Off Peak	4,262	4,219	99%	29	1%	1%

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. This is consistent with the day-ahead energy market objective of clearing resources (including physical and virtual resources) to meet the total demand (including physical and virtual demand) at the lowest bid production cost for the system over the 24 hour period. 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.[143]

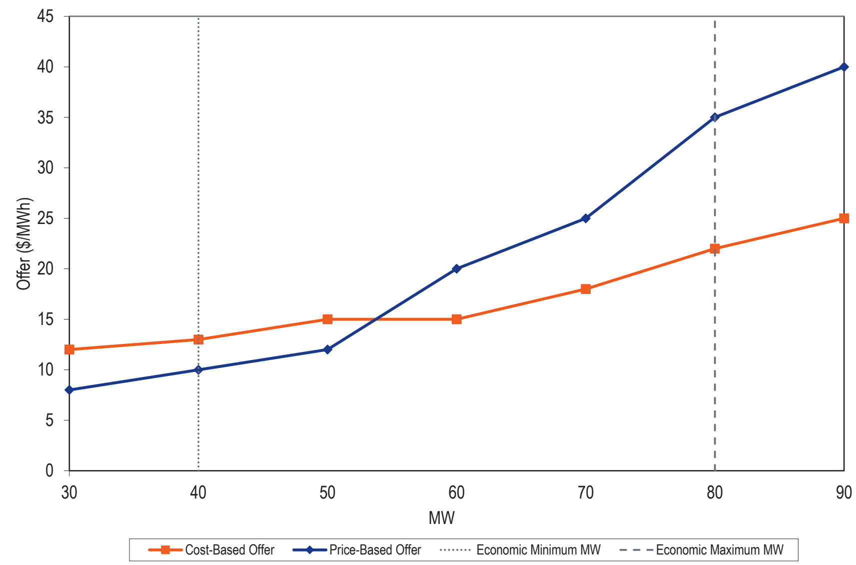
$$\text{Total Dispatch Cost} = \text{Startup Cost} + \sum_{\text{Min Run}} \text{Hourly Dispatch Cost}$$

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 3-52 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 3-52 Offers with varying markups at different MW output levels



143 See OA Schedule 1 § 6.4.1(g).

Table 3-92 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 six 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 3-92 Units offered with crossing curves in the day-ahead and real-time energy markets: January through June, 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%
Total	456,351	4,903,276	9.3%	403,287	4,324,355	9.3%

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 3-93 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 3-93 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 June, 2021[144]

	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%
Total	57,902	4,903,276	1.2%	41,484	4,324,355	1.0%

144 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.

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 3-53 shows an example of offers from a unit that has a positive markup and a price-based offer with a lower economic minimum MW than the cost-based offer. Keeping the startup cost, Minimum Run Time and no load cost constant between the price-based offer and cost-based offer, the dispatch cost for this unit is lower on the price-based offer than on the cost-based offer. However, the price-based offer includes a positive markup and could result in setting the market price at a noncompetitive level even after the resource owner fails the TPS test.

Figure 3-53 Offers with a positive markup but different economic minimum MW

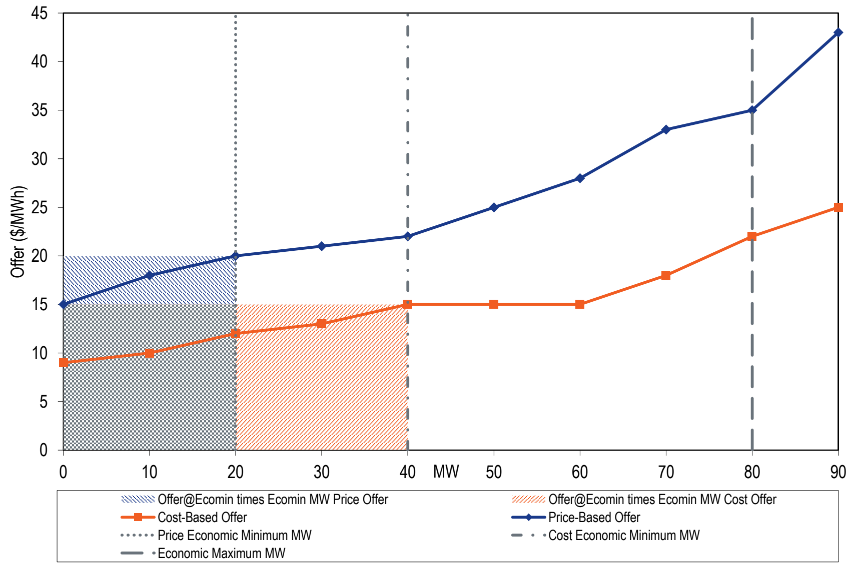


Table 3-94 shows the number and percent of unit schedule hours when units offered lower economic minimum MW in price-based offers than in cost-based offers while having a positive markup in the price-based offer.

Table 3-94 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 June, 2021[145]

	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%
Total	6,070	4,903,276	0.1%	4,392	4,324,355	0.1%

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 3-54 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 3-95 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 six months of 2021.

145 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.

Figure 3-54 Dual fuel unit offers

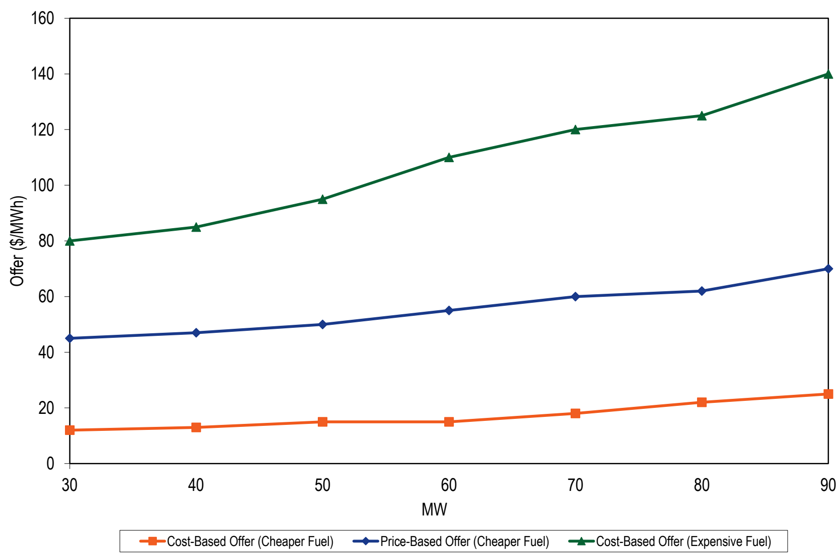


Table 3-95 Dual fuel unit offers with negative markup but different fuel: January through June, 2021

	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%
Total	18,300	1,106,232	1.7%	18,300	963,828	1.9%

These issues can be solved by simple rule changes.[146] The MMU recommends that markup of price-based offers over cost-based offers be constant across the offer curve, that there be at least one cost-based offer using the same fuel as the available price-based offer, and that operating parameters on parameter limited schedules (PLS) be at least as flexible as price-based non-PLS offers.

Levels of offer capping have historically been low in PJM, as shown in Table 3-97. 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.[147] 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 3-96 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

146 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.
147 See OA Schedule 1 § 6.4.1.

the units in the PJM energy market.[148] 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 3-96 Offer capping statistics – energy only: January through June, 2017 to 2021

	Real-Time		Day-Ahead	
(Jan-Jun)	Unit Hours Capped	MWh Capped	Unit Hours Capped	MWh Capped
2017	0.2%	0.1%	0.0%	0.0%
2018	1.3%	0.5%	0.1%	0.1%
2019	0.8%	0.7%	0.5%	0.4%
2020	0.9%	1.4%	1.2%	1.2%
2021	1.3%	1.1%	1.3%	0.8%

Table 3-97 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 3-98. 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 3-96. 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 3-98.

Table 3-97 Offer capping statistics for energy and reliability: January through June, 2017 to 2021

	Real-Time		Day-Ahead	
(Jan-Jun)	Unit Hours Capped	MWh Capped	Unit Hours Capped	MWh Capped
2017	0.3%	0.5%	0.2%	0.4%
2018	1.5%	0.8%	0.2%	0.4%
2019	0.8%	0.7%	0.5%	0.4%
2020	0.9%	1.4%	1.2%	1.2%
2021	1.3%	1.1%	1.3%	0.8%

Table 3-98 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 3-98 Offer capping statistics for reliability: January through June, 2017 to 2021

	Real-Time		Day-Ahead	
(Jan-Jun)	Unit Hours Capped	MWh Capped	Unit Hours Capped	MWh Capped
2017	0.13%	0.40%	0.16%	0.38%
2018	0.18%	0.32%	0.13%	0.25%
2019	0.01%	0.02%	0.01%	0.02%
2020	0.01%	0.01%	0.00%	0.00%
2021	0.01%	0.01%	0.02%	0.01%

148 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.

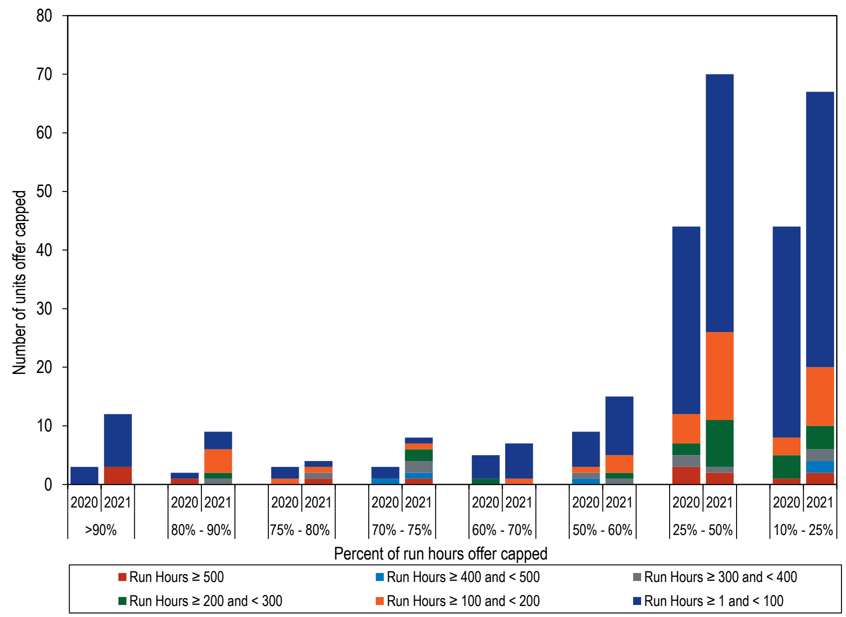
Table 3-99 presents data on the frequency with which units were offer capped in the first six months of 2020 and 2021 as a result of failing the TPS test to provide energy for constraint relief in the real-time energy market and for reliability reasons. Table 3-99 shows that 12 units were offer capped for 90 percent or more of their run hours in the first six months of 2021 compared to three units in the first six months of 2020.

Table 3-99 Real-time offer capped unit statistics: January through June, 2020 and 2021

		Offer-Capped Hours					
Run Hours Offer-Capped, Percent Greater Than Or Equal To:	Jan - Jun	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	3
	2021	3	0	0	0	0	9
80% and < 90%	2020	1	0	0	0	0	1
	2021	0	0	1	1	4	3
75% and < 80%	2020	0	0	0	0	1	2
	2021	1	0	1	0	1	1
70% and < 75%	2020	0	1	0	0	0	2
	2021	1	1	2	2	1	1
60% and < 70%	2020	0	0	0	1	0	4
	2021	0	0	0	0	1	6
50% and < 60%	2020	0	1	1	0	1	6
	2021	0	0	1	1	3	10
25% and < 50%	2020	3	0	2	2	5	32
	2021	2	0	1	8	15	44
10% and < 25%	2020	1	0	0	4	3	36
	2021	2	2	2	4	10	47

Figure 3-55 shows the frequency with which units were offer capped in the first six 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 3-55 Real-time offer capped unit statistics: January through June, 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.[149] 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

149 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.

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 3-100 shows the average markup index of marginal units in the real-time energy market, by offer price category using unadjusted cost-based offers. Table 3-101 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.[150] 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.

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.[151]

In the first six months of 2021, the average markup index in the real-time market was -0.02. The average dollar markups of units with offer prices less than $10 was negative (-$7.36 per MWh) when using unadjusted cost-based offers. The average dollar markups of units with offer prices between $10 and $15 was negative (-$1.23 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 six months of 2021, less than one percent had offer prices above $400 per MWh. Among the units that were marginal in the first six 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 six months of 2021 was more than $400, and the highest markup in the first six months of 2020 was more than $150.

Table 3-100 Average, real-time marginal unit markup index (By offer price category unadjusted): January through June, 2020 and 2021

	2020 (Jan - Jun)			2021 (Jan - Jun)		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $10	(0.02)	($1.15)	13.3%	0.07	($7.36)	7.3%
$10 to $15	0.04	$0.43	45.0%	(0.07)	($1.23)	7.6%
$15 to $20	0.02	($0.12)	30.9%	(0.04)	($0.97)	32.1%
$20 to $25	0.04	$0.63	8.4%	(0.02)	($0.81)	27.2%
$25 to $50	0.18	$5.96	1.9%	(0.00)	($0.90)	22.4%
$50 to $75	0.54	$31.85	0.2%	0.20	$9.67	1.7%
$75 to $100	0.68	$60.37	0.1%	0.16	$12.69	0.5%
$100 to $125	0.77	$87.54	0.0%	0.09	$8.86	0.4%
$125 to $150	0.32	$41.51	0.0%	0.28	$37.14	0.2%
$150 to $400	0.53	$90.42	0.1%	0.12	$22.84	0.6%
All Offers	0.03	$0.48	100.0%	(0.02)	($0.76)	100.0%

150 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.

151 See PJM. "Manual 15: Cost Development Guidelines," Rev. 37 (Dec. 9, 2020).

Table 3-101 Average, real-time marginal unit markup index (By offer price category adjusted): January through June, 2020 and 2021

	2020 (Jan - Jun)			2021 (Jan - Jun)		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $10	0.03	($0.66)	13.3%	0.08	($7.28)	7.3%
$10 to $15	0.13	$1.56	45.0%	0.00	($0.10)	7.6%
$15 to $20	0.10	$1.46	30.9%	0.03	$0.44	32.1%
$20 to $25	0.12	$2.54	8.4%	0.05	$1.06	27.2%
$25 to $50	0.25	$8.20	1.9%	0.07	$1.72	22.4%
$50 to $75	0.58	$34.24	0.2%	0.27	$13.52	1.7%
$75 to $100	0.71	$62.92	0.1%	0.22	$18.24	0.5%
$100 to $125	0.79	$89.93	0.0%	0.17	$17.44	0.4%
$125 to $150	0.39	$49.81	0.0%	0.34	$45.30	0.2%
$150 to $400	0.58	$97.56	0.1%	0.20	$36.14	0.6%
All Offers	0.11	$1.79	100.0%	0.05	$1.15	100.0%

Table 3-102 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.[152] Table 3-103 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 six months of 2021, using unadjusted cost-based offers for coal units, 54.46 percent of marginal coal units had negative markups. In the first six months of 2021, using adjusted cost-based offers for coal units, 33.73 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 33.83 percent in the first six months of 2020 to 50.99 percent in the first six 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 3-102 Percent of marginal units with markup below, above and equal to zero (By fuel type with unadjusted offers): January through June, 2020 and 2021

	2020 (Jan - Jun)			2021 (Jan - Jun)		
Type/Fuel	Negative	Zero	Positive	Negative	Zero	Positive
Coal	58.86%	23.67%	17.47%	54.46%	22.80%	22.74%
Gas	33.83%	3.90%	62.27%	50.99%	16.50%	32.51%
Oil	0.00%	100.00%	0.00%	12.66%	83.55%	3.79%

Table 3-103 Percent of marginal units with markup below, above and equal to zero (By fuel type with adjusted offers): January through June, 2020 and 2021

	2020 (Jan - Jun)			2021 (Jan - Jun)		
Type/Fuel	Negative	Zero	Positive	Negative	Zero	Positive
Coal	36.32%	17.42%	46.26%	33.73%	13.52%	52.75%
Gas	20.88%	2.71%	76.41%	31.70%	6.47%	61.84%
Oil	0.00%	84.62%	15.38%	2.48%	81.20%	16.32%

Figure 3-56 shows the frequency distribution of hourly markups for all gas units offered in the first six months of 2020 and the first six 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.[153] Of the gas units offered in the PJM market in the first six months of 2021, 17.8 percent of gas unit hours had a maximum markup that was negative and 11.5 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 six months of 2021 compared to the first six months of 2020 while the share of marginal gas units with negative markups increased.

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

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

Figure 3-56 Frequency distribution of highest markup of gas units offered using unadjusted cost offers: January through June, 2020 and 2021

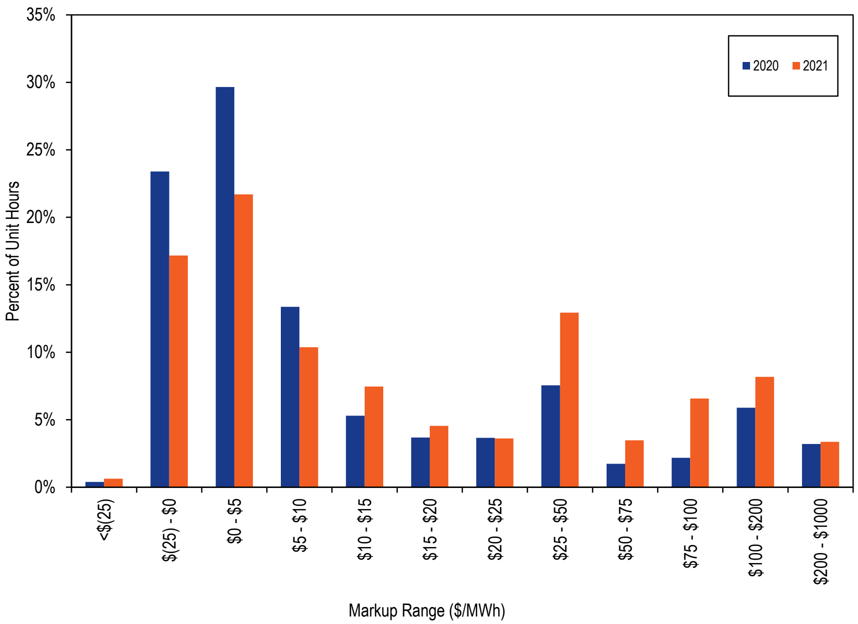


Figure 3-57 Frequency distribution of highest markup of coal units offered using unadjusted cost offers: January through June, 2020 and 2021

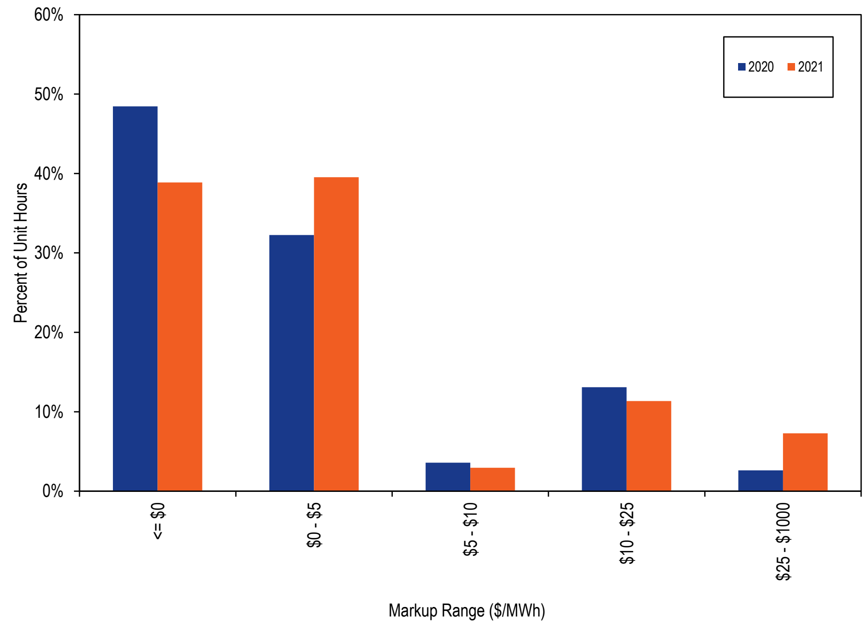
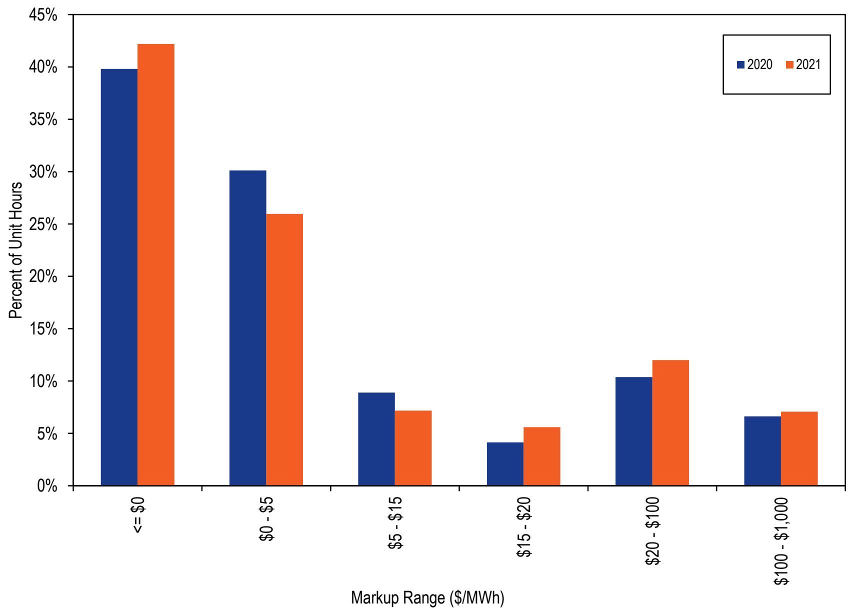


Figure 3-57 shows the frequency distribution of hourly markups for all coal units offered in the first six months of 2020 and the first six months of 2021 using unadjusted cost-based offers. Of the coal units offered in the PJM market in the first six months of 2021, 38.9 percent of coal unit hours had a maximum markup that was negative or equal to zero, decreasing from 48.4 in the first six 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 six months of 2021 compared to the first six months of 2020.

Figure 3-58 shows the frequency distribution of hourly markups for all offered oil units in the first six months of 2020 and the first six months of 2021 using unadjusted cost-based offers. Of the oil units offered in the PJM market in the first six months of 2021, 42.1 percent of oil unit hours had a maximum markup that was negative or equal to zero. More than 7.0 percent of oil fired unit hours had a maximum markup above $100 per MWh.

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

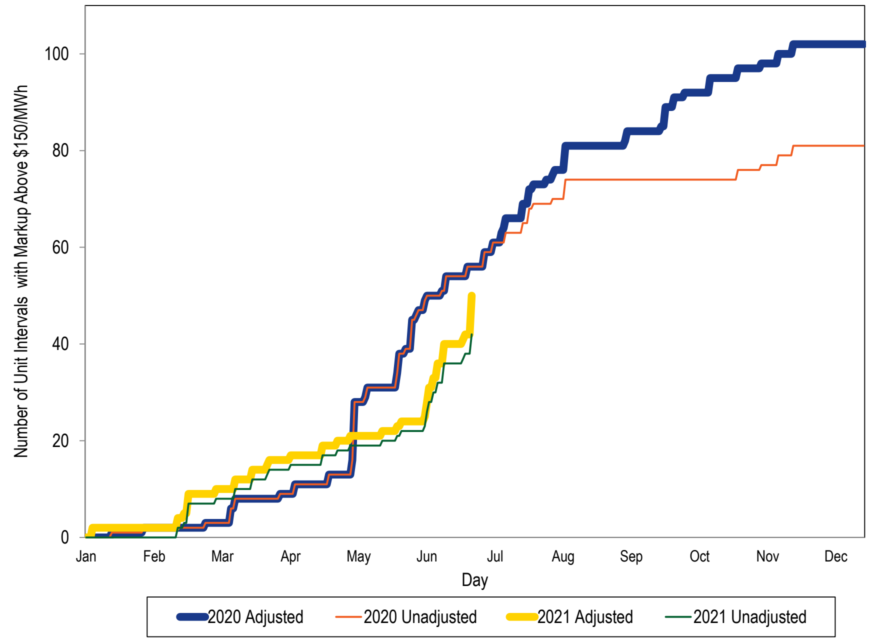


The markup frequency distributions show that a significant proportion of units make price-based offers less than the cost-based offers permitted under the PJM market rules. This behavior means that competitive price-based offers reveal actual unit marginal costs and that PJM market rules permit the inclusion 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 3-59 shows the number of marginal unit intervals in the first six 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 3-59 Cumulative number of unit intervals with markups above $150 per MWh: January through June, 2020 and 2021



Day-Ahead Markup Index

Table 3-104 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 (-$0.91 per MWh) when using unadjusted cost-based offers. The average dollar markups of units with offer prices between $10 and $15 was negative (-$0.49 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 June, 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 six months of 2021 was more than $120 per MWh while the highest markup in the first six months of 2020 was less than $80 per MWh.

Table 3-104 Average day-ahead marginal unit markup index (By offer price category, unadjusted): January through June, 2020 and 2021

	2020 (Jan - Jun)			2021 (Jan - Jun)		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $10	0.01	($0.71)	8.7%	0.17	($0.91)	6.4%
$10 to $15	0.09	$0.96	36.8%	(0.01)	($0.49)	3.4%
$15 to $20	0.15	$2.03	41.1%	0.07	$0.94	25.7%
$20 to $25	0.01	($0.28)	11.2%	(0.00)	($0.35)	31.9%
$25 to $50	0.03	$0.57	2.2%	0.03	$0.28	28.9%
$50 to $75	0.00	$0.00	0.0%	0.08	($20.89)	2.4%
$75 to $100	0.51	$47.56	0.0%	0.24	$21.26	0.5%
$100 to $125	(0.05)	($6.24)	0.0%	0.13	$10.23	0.4%
$125 to $150	0.00	$0.00	0.1%	0.10	$11.98	0.2%
>= $150	0.15	$25.35	0.0%	0.03	$4.94	0.2%
All Offers	0.10	$1.12	100.0%	0.04	($0.19)	100.0%

Table 3-105 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 six months of 2021, 25.7 percent of marginal generating units 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 0.08 in the first six months of 2020, to 0.22 in the first six months of 2021 in the offer price category less than $10.

Table 3-105 Average day-ahead marginal unit markup index (By offer price category, adjusted): January through June, 2020 and 2021

	2020 (Jan - Jun)			2021 (Jan - Jun)		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $10	0.08	($0.26)	8.7%	0.22	($0.68)	6.4%
$10 to $15	0.16	$2.05	36.8%	0.06	$0.65	3.4%
$15 to $20	0.22	$3.41	41.1%	0.15	$2.46	25.7%
$20 to $25	0.09	$1.72	11.2%	0.08	$1.70	31.9%
$25 to $50	0.11	$3.09	2.2%	0.11	$3.09	28.9%
$50 to $75	0.00	$0.00	0.0%	0.15	($13.83)	2.4%
$75 to $100	0.52	$48.18	0.0%	0.30	$26.49	0.5%
$100 to $125	0.04	$5.11	0.0%	0.19	$18.50	0.4%
$125 to $150	0.09	$12.16	0.1%	0.14	$18.09	0.2%
>= $150	0.15	$25.35	0.0%	0.11	$17.76	0.2%
All Offers	0.17	$2.42	100.0%	0.12	$1.99	100.0%

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 3-106 shows the caps on the three parts of cost-based and price-based offers.

Table 3-106 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 3-107 shows the number of units that chose the cost-based option and the price-based option. In the first six 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, two percentage points higher than in the first six months of 2020.

Table 3-107 Number of units selecting cost-based and price-based no load and start costs: January through June, 2020 and 2021

	2020		2021	
No Load and Start Cost Option	Number of units	Percent	Number of units	Percent
Cost-Based	539	90%	522	92%
Price-Based	58	10%	45	8%
Total	597	100%	567	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 3-108 shows the average markup in the no load and start costs in the first six 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 3-108 No load and start cost markup: January through June, 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	(5%)	546%	669%	703%
2021	Cost-Based	(8%)	(8%)	(9%)	(9%)
	Price-Based	(59%)	373%	429%	530%

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 six months of 2021, 7.3 percent of the marginal units set prices based on cost-based offers, 0.6 percentage points higher than in the first six 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."[154]

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.[155]

154 See 167 FERC ¶ 61,030 (2019).
155 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 3-109 shows the status of all fuel cost policies (FCP) as of June 30, 2021. As of June 30, 2021, 735 units (87 percent) had an FCP passed by the MMU, zero units had an FCP under MMU review (submitted) and 110 units (13 percent) had an FCP failed by the MMU. The units with fuel cost policies failed by the MMU represented 23,163 MW. All units' FCPs were approved by PJM. The number of units with fuel cost policies passed by the MMU decreased by 38 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. As of June 30, 2021, 469 units did not have FCPs approved by PJM. Units without approved FCPs cannot submit nonzero cost based offers.

Table 3-109 FCP Status for PJM generating units: June 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	735	0	110	845
Total	735	0	110	845

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.[156] 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.[157] 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.[158] 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').[159]

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.

156 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").
157 Protest of the Independent Market Monitor for PJM, Docket No. ER16-372-002 (September 16, 2016) at P 8 ("September 16th Filing").
158 October 7th Filing at P12; 158 FERC ¶ 61,133 at P 57 (2017).
159 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:[160] 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.

160 See PJM Operating Agreement Schedule 2 § 2.3 (a).

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.[161] Penalties are assessed when both PJM and the MMU are in agreement.

In the first six months of 2021, 103 penalty cases were identified, 61 resulted in assessed cost-based offer penalties, five resulted in disagreement between the MMU and PJM, and 37 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 102 units owned by 16 different companies. Table 3-111 shows the penalties by the year in which participants were notified.

161 See OA Schedule 2 § 6.

Table 3-110 Cost-based offer penalty cases by year notified: May 2017 through June 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	103	61	5	37	102	16
Total	546	471	37	38	385	58

Since 2017, 546 penalty cases have been identified, 471 resulted in assessed cost-based offer penalties, 37 resulted in disagreement between the MMU and PJM, and 38 remain pending PJM's determination. The 471 cases were from 385 units owned by 58 different companies. The total penalties were $4.6 million, charged to units that totaled 155,899 available MW. The average penalty was $1.32 per available MW. This means that a 100 MW unit would have paid a penalty of $3,167.[162] Table 3-111 shows the total cost-based offer penalties since 2017 by year.

Table 3-111 Cost-based offer penalties by year: May 2017 through June 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	229	29	$1,625,915	72,777	$0.96
2021	78	13	$708,062	20,051	$1.53
Total	605	58	$4,647,427	155,899	$1.32

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.

162 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.[163]

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 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.[164] 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.

163 172 FERC ¶ 61,094.

164 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.[165] On October 28, 2019, FERC issued a final order accepting PJM's compliance filing.[166] 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.[167]

165 167 FERC ¶ 61,030.
166 168 FERC ¶ 61,134.
167 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 3-112 shows the amount of capacity offered within several ranges of VOM costs. Table 3-112 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 3-112 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.[168]

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.

168 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.[169]

169 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.[170] 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 six months of 2021, one unit qualified for an FMU adder in January.

Table 3-113 shows, by month, the number of FMUs and AUs from January 2020 through June 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.

170 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 3-113 Number of frequently mitigated units and associated units (By month): January 2020 through June 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				
August	1	0	0	1				
September	1	0	2	3				
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 will no longer be 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 will 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 3-114 shows the contribution to real-time, load-weighted LMP by individual marginal resource owners.[171] The contribution of each marginal resource to price at each load bus is calculated for each five-minute interval of the first six months of 2021, and summed by the parent company that offers the marginal resource into the real-time energy market. In the first six months of 2021, the offers of one company resulted in 14.2 percent of the real-time, load-weighted PJM system LMP and the offers of the top four companies resulted in 43.3 percent of the real-time, load-weighted, average PJM system LMP. In the first six months of 2021, the offers of one company resulted in 13.4 percent of the peak hour real-time, load-weighted PJM system LMP.

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

Table 3-114 Marginal unit contribution to real-time, load-weighted LMP (By parent company): January through June, 2020 and 2021

2020 (Jan - Jun)						2021 (Jan - Jun)					
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	16.2%	16.2%	1	17.3%	17.3%	1	14.2%	14.2%	1	13.4%	13.4%
2	12.4%	28.6%	2	14.8%	32.2%	2	11.3%	25.4%	2	12.0%	25.4%
3	10.7%	39.3%	3	10.2%	42.4%	3	9.6%	35.1%	3	10.1%	35.4%
4	7.8%	47.2%	4	7.4%	49.8%	4	8.2%	43.3%	4	8.6%	44.0%
5	5.9%	53.0%	5	5.6%	55.4%	5	7.3%	50.6%	5	6.4%	50.4%
6	5.6%	58.6%	6	4.8%	60.2%	6	6.1%	56.6%	6	6.1%	56.5%
7	4.9%	63.6%	7	4.6%	64.8%	7	4.5%	61.1%	7	4.2%	60.7%
8	4.5%	68.1%	8	3.6%	68.4%	8	3.1%	64.2%	8	3.5%	64.2%
9	3.4%	71.5%	9	2.8%	71.2%	9	3.1%	67.3%	9	3.2%	67.4%
Other (68 companies)	28.5%	100.0%	Other (61 companies)	28.8%	100.0%	Other (71 companies)	32.7%	100.0%	Other (69 companies)	32.6%	100.0%

Figure 3-60 shows the marginal unit contribution to the real-time, load-weighted PJM system LMP summed by parent companies since 2012.

Figure 3-60 Marginal unit contribution to real-time, load-weighted LMP (By parent company): January through June, 2012 through 2021

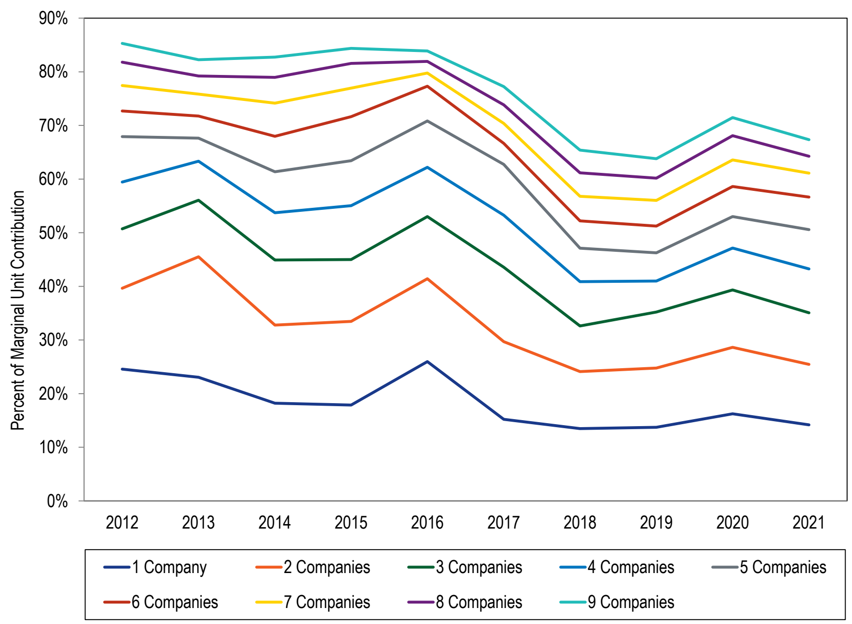


Table 3-115 shows the contribution to day-ahead, load-weighted LMP by individual marginal resource owners.[172] The contribution of each marginal resource to price at each load bus is calculated hourly, and summed by the parent company that offers the marginal resource into the day-ahead energy market. The results show that in the first six months of 2021, the offers of one company contributed 6.6 percent of the day-ahead, load-weighted, PJM system LMP and that the offers of the top four companies contributed 24.0 percent of the day-ahead, load-weighted, average, PJM system LMP.

Table 3-115 Marginal resource contribution to day-ahead, load-weighted LMP (By parent company): January through June, 2020 and 2021

2020 (Jan - Jun)						2021 (Jan - Jun)					
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	13.3%	13.3%	1	17.7%	17.7%	1	6.6%	6.6%	1	6.8%	6.8%
2	11.7%	25.0%	2	13.7%	31.4%	2	6.4%	13.0%	2	6.2%	12.9%
3	10.5%	35.5%	3	13.5%	44.8%	3	5.5%	18.5%	3	5.3%	18.2%
4	5.6%	41.2%	4	5.3%	50.2%	4	5.5%	24.0%	4	5.0%	23.1%
5	4.9%	46.1%	5	4.8%	54.9%	5	5.3%	29.3%	5	4.8%	27.9%
6	4.5%	50.6%	6	4.2%	59.2%	6	5.1%	34.4%	6	4.0%	31.9%
7	4.1%	54.7%	7	3.9%	63.1%	7	3.5%	37.9%	7	3.3%	35.2%
8	3.6%	58.3%	8	3.4%	66.5%	8	3.1%	40.9%	8	3.1%	38.3%
9	3.2%	61.5%	9	3.4%	70.0%	9	2.8%	43.7%	9	3.0%	41.3%
Other (132 companies)	38.5%	100.0%	Other (126 companies)	30.0%	100.0%	Other (131 companies)	56.3%	100.0%	Other (127 companies)	58.7%	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.[173] 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

172 Id.

173 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.

Table 3-116 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 decreased from $1.93 per MWh in the first six months of 2020 to $1.91 per MWh in the first six months of 2021. The adjusted markup contribution of coal units in the first six months of 2021 was $0.22 per MWh. The adjusted markup component of gas fired units in the first six months of 2021 was $1.81 per MWh, an increase of $0.08 per MWh from the first six 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 six months of 2021, among the wind units that were marginal, 87.1 percent had negative offer prices.

Table 3-116 Markup component of real-time, load-weighted, average LMP by primary fuel type and unit type: January through June, 2020 and 2021[174]

		2020 (Jan - Jun)		2021 (Jan - Jun)	
Fuel	Technology	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)
Coal	Steam	($0.51)	$0.14	($0.28)	$0.22
Gas	CC	$0.82	$1.65	$0.09	$1.32
Gas	CT	$0.10	$0.17	$0.20	$0.45
Gas	RICE	$0.05	$0.05	$0.00	$0.01
Gas	Steam	($0.10)	($0.07)	($0.00)	$0.03
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	$0.01
Oil	CT	$0.00	$0.00	($0.00)	$0.02
Oil	RICE	$0.00	$0.00	$0.00	$0.00
Oil	Steam	($0.01)	($0.01)	($0.03)	($0.03)
Other	Steam	($0.00)	($0.00)	$0.00	$0.00
Wind	Wind	($0.01)	($0.01)	($0.11)	($0.11)
Total		$0.34	$1.93	($0.13)	$1.91

Markup Component of Real-Time Price

Table 3-117 shows the markup component, calculated using unadjusted offers, of average prices and of average monthly on peak and off peak prices. Table 3-118 shows the markup component, calculated using adjusted offers, of average prices and of average monthly on peak and off peak prices. In the first six months of 2021, when using unadjusted cost-based offers, -$0.13 per MWh of the PJM real-time, load-weighted, average LMP was attributable to markup. Using adjusted cost-based offers, $1.91 per MWh of the PJM real-time, load-weighted, average LMP was attributable to markup. In the first six months of 2021, the peak markup component was highest in June, $2.76 per MWh using unadjusted cost-based offers and peak markup component was highest in June, $5.22 per MWh using adjusted cost-based offers. This corresponds to 6.9 percent and 13.1 percent of the real-time, peak, load-weighted, average LMP in June.

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

Table 3-117 Monthly markup components of real-time, load-weighted, LMP (Unadjusted): January 2020 through June, 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	($0.45)	($0.30)	($0.58)
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)	($1.85)	($2.88)	($0.71)
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)			
Aug	$1.80	$2.88	$0.70			
Sep	$0.47	$0.97	($0.08)			
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)	($0.13)	$0.18	($0.43)

Table 3-118 Monthly markup components of real-time, load-weighted, LMP (Adjusted): January 2020 through June, 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	$1.43	$1.73	$1.17
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	($0.35)	($1.47)	$0.89
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			
Aug	$3.61	$4.83	$2.35			
Sep	$1.89	$2.50	$1.22			
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	$1.91	$2.34	$1.47

Hourly Markup Component of Real-Time Prices

Figure 3-61 shows the markup contribution to the hourly load-weighted, LMP using unadjusted cost offers in 2020 and the first six months of 2021. Figure 3-62 shows the markup contribution to the hourly load-weighted, LMP using adjusted cost-based offers in 2020 and the first six months of 2021.

Figure 3-61 Markup contribution to real-time, hourly, load-weighted LMP (Unadjusted): 2020 through June 2021

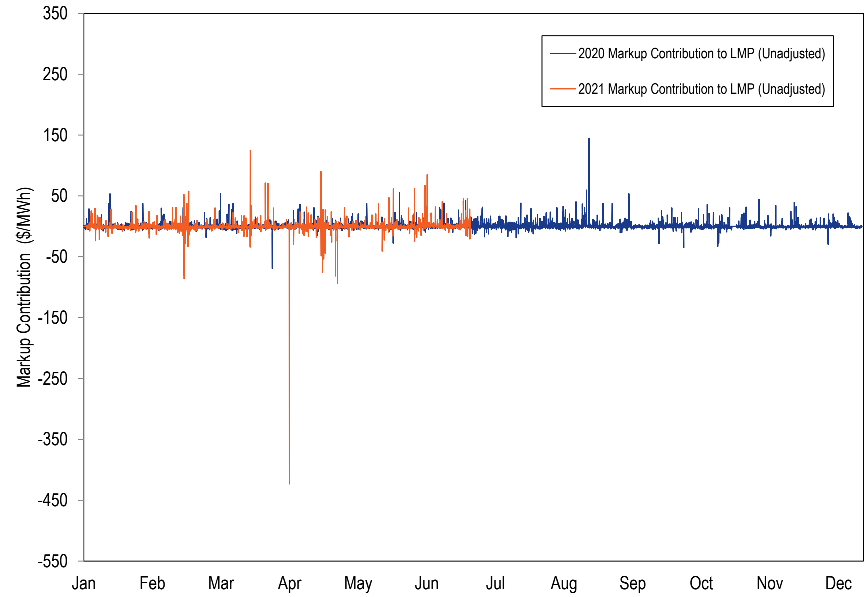
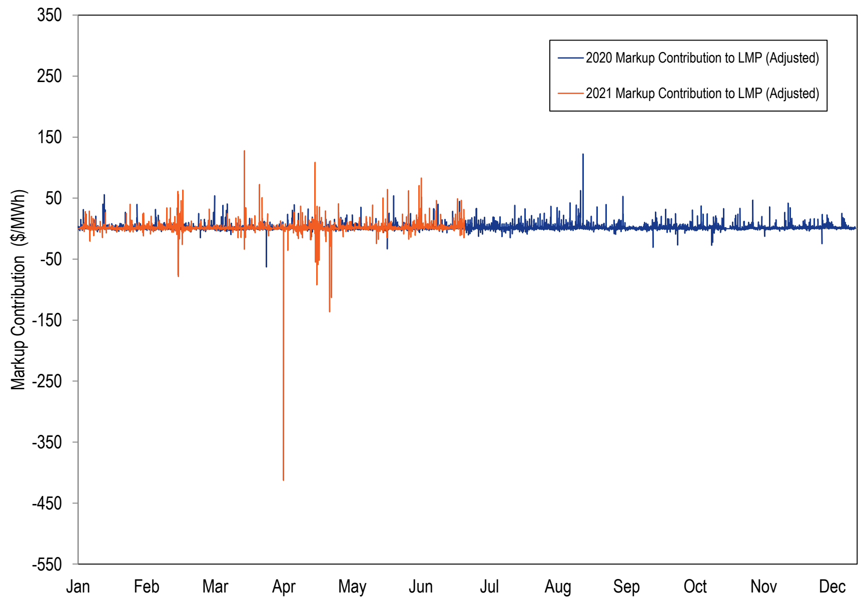


Figure 3-62 Markup contribution to real-time, hourly, load-weighted, LMP (Adjusted): 2020 through June 2021



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 six months of 2020 and the first six months of 2021 in Table 3-119 and for adjusted offers in Table 3-120.[175] The smallest zonal all hours average markup component using unadjusted offers in the first six months of 2021, was in the DOM Control Zone, -$0.51 per MWh, while the highest was in the REC Control Zone, $0.64 per MWh. The smallest zonal on peak average markup component using unadjusted offers in the first six months of 2021, was in the OVEC Control Zone, -$0.48 per MWh, while the highest was in the REC Control Zone, $1.39 per MWh.

Table 3-119 Average, real-time, zonal markup component (Unadjusted): January through June, 2020 and 2021

	2020 (Jan - Jun)			2021 (Jan - Jun)		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
ACEC	$0.29	$0.68	($0.10)	$0.10	$0.70	($0.48)
AEP	$0.35	$0.81	($0.12)	($0.21)	$0.03	($0.45)
APS	$0.40	$0.93	($0.13)	($0.27)	($0.03)	($0.51)
ATSI	$0.41	$0.87	($0.08)	($0.05)	$0.12	($0.22)
BGE	$0.59	$1.28	($0.10)	($0.14)	($0.06)	($0.22)
COMED	$0.28	$0.81	($0.29)	($0.07)	$0.30	($0.45)
DAY	$0.41	$0.88	($0.09)	($0.17)	($0.03)	($0.32)
DOM	$0.38	$0.89	($0.14)	($0.51)	($0.23)	($0.79)
DPL	$0.22	$0.62	($0.19)	$0.24	$0.81	($0.32)
DUKE	$0.38	$0.87	($0.13)	($0.21)	($0.10)	($0.33)
DUQ	$0.48	$1.04	($0.10)	($0.09)	$0.03	($0.22)
EKPC	$0.33	$0.85	($0.17)	($0.29)	($0.16)	($0.42)
JCPLC	$0.28	$0.62	($0.09)	$0.16	$0.62	($0.32)
MEC	$0.25	$0.60	($0.12)	$0.07	$0.61	($0.49)
OVEC	$0.17	$0.62	($0.23)	($0.33)	($0.48)	($0.20)
PE	$0.32	$0.70	($0.09)	$0.05	$0.53	($0.44)
PECO	$0.23	$0.62	($0.17)	$0.10	$0.66	($0.48)
PEPCO	$0.48	$1.07	($0.12)	($0.14)	($0.21)	($0.06)
PPL	$0.23	$0.45	$0.01	$0.10	$0.57	($0.38)
PSEG	$0.25	$0.62	($0.13)	$0.23	$0.72	($0.27)
REC	$0.21	$0.53	($0.14)	$0.64	$1.39	($0.19)

175 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 3-120 Average, real-time, zonal markup component (Adjusted): January through June 2020 and 2021

	2020 (Jan - Jun)			2021 (Jan - Jun)		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
ACEC	$1.80	$2.30	$1.31	$1.97	$2.66	$1.29
AEP	$1.96	$2.57	$1.35	$1.83	$2.20	$1.46
APS	$2.02	$2.68	$1.34	$1.78	$2.16	$1.40
ATSI	$2.03	$2.65	$1.39	$1.98	$2.25	$1.70
BGE	$2.29	$3.13	$1.45	$2.20	$2.46	$1.95
COMED	$1.76	$2.47	$1.01	$1.93	$2.44	$1.39
DAY	$2.10	$2.71	$1.44	$1.97	$2.26	$1.67
DOM	$2.01	$2.67	$1.36	$1.64	$2.10	$1.19
DPL	$1.76	$2.24	$1.28	$2.15	$2.78	$1.53
DUKE	$1.99	$2.62	$1.35	$1.87	$2.13	$1.60
DUQ	$2.09	$2.81	$1.35	$1.90	$2.12	$1.67
EKPC	$1.95	$2.59	$1.33	$1.82	$2.12	$1.54
JCPLC	$1.81	$2.27	$1.34	$2.06	$2.63	$1.47
MEC	$1.80	$2.25	$1.32	$2.00	$2.64	$1.33
OVEC	$1.74	$2.34	$1.21	$1.65	$1.65	$1.65
PE	$1.85	$2.35	$1.32	$2.02	$2.61	$1.41
PECO	$1.73	$2.21	$1.24	$1.92	$2.56	$1.26
PEPCO	$2.14	$2.86	$1.40	$2.05	$2.11	$1.98
PPL	$1.71	$2.01	$1.39	$1.98	$2.56	$1.38
PSEG	$1.78	$2.26	$1.29	$2.20	$2.87	$1.51
REC	$1.74	$2.17	$1.26	$2.72	$3.71	$1.61

Markup by Real-Time Price Levels

Table 3-121 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 3-121 Real-time markup contribution (By load-weighted, LMP category, unadjusted): January through June, 2020 and 2021

	2020 (Jan - Jun)		2021 (Jan - Jun)	
LMP Category	Markup Component	Frequency	Markup Component	Frequency
< $10	($0.53)	2.5%	$0.00	0.0%
$10 to $15	($0.22)	25.9%	($0.82)	0.9%
$15 to $20	($0.43)	43.8%	($0.50)	22.7%
$20 to $25	$0.29	18.6%	($0.55)	32.4%
$25 to $50	$2.80	7.9%	($0.07)	36.8%
$50 to $75	$7.69	1.0%	$1.39	4.1%
$75 to $100	$5.86	0.2%	$4.37	1.5%
$100 to $125	$6.26	0.0%	$3.25	1.0%
$125 to $150	$1.20	0.0%	$3.91	0.3%
>= $150	$2.85	0.0%	$7.46	0.4%

Table 3-122 Real-time markup contribution (By load-weighted, LMP category, adjusted): January through June, 2020 and 2021

	2020 (Jan - Jun)		2021 (Jan - Jun)	
LMP Category	Markup Component	Frequency	Markup Component	Frequency
< $10	($0.05)	2.6%	$0.00	0.0%
$10 to $15	$0.41	25.7%	($0.12)	0.9%
$15 to $20	$0.41	44.1%	$0.26	23.2%
$20 to $25	$1.26	18.5%	$0.41	32.5%
$25 to $50	$3.89	7.7%	$1.06	36.3%
$50 to $75	$9.21	1.0%	$2.89	4.0%
$75 to $100	$6.85	0.2%	$6.57	1.5%
$100 to $125	$7.09	0.0%	$6.10	0.9%
$125 to $150	$3.18	0.0%	$7.71	0.3%
>= $150	$3.62	0.0%	$9.77	0.4%

Markup by Company

Table 3-123 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 six months of 2021, when using unadjusted cost-based offers, the markup of one company accounted for 0.9 percent of the load-weighted, average LMP, the markup of the top five companies accounted for 2.4 percent of the load-weighted, average LMP and the markup of all companies accounted for -0.4 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 decreased in the first six 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 decreased in the first six months of 2021. The markup contribution of a unit to the real-time, load-weighted, average LMP can be positive or negative.

Table 3-123 Markup component of real-time, load-weighted, average LMP by Company: January through June, 2020 and 2021

	2020 (Jan - Jun)				2021 (Jan - Jun)			
	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	$0.39	2.0%	$0.62	3.2%	$0.26	0.9%	$0.43	1.4%
Top 2 Companies	$0.57	2.9%	$0.85	4.4%	$0.46	1.5%	$0.82	2.7%
Top 3 Companies	$0.70	3.6%	$1.06	5.5%	$0.63	2.1%	$1.08	3.5%
Top 4 Companies	$0.83	4.3%	$1.24	6.4%	$0.69	2.2%	$1.30	4.3%
Top 5 Companies	$0.91	4.7%	$1.40	7.2%	$0.74	2.4%	$1.48	4.8%
All Companies	$0.34	1.8%	$1.93	9.9%	($0.13)	(0.4%)	$1.92	6.3%

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 3-124. INC, DEC and up to congestion transactions (UTC) have zero markups. UTCs were 36.5 percent of marginal resources, INCs were 17.7 percent of marginal resources and DECs were 25.1 percent of marginal resources in the first six 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 3-124 shows the markup component of LMP for marginal generating resources. Generating resources were only 20.4 percent of marginal resources in the first six months of 2021. Using adjusted cost-based offers, the markup component of LMP for marginal generating resources increased for coal fired steam units from $0.02 to $0.31 per MWh and increased for gas fired CC units from $0.98 to $1.00 per MWh.

Table 3-124 Markup component of day-ahead, load-weighted, average LMP by primary fuel type and technology type: January through June, 2020 and 2021

		2020 (Jan - Jun)			2021 (Jan - Jun)		
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	($0.67)	$0.02	34.0%	($0.27)	$0.31	36.3%
Gas	CC	$0.58	$0.98	57.6%	$0.12	$1.00	53.6%
Gas	CT	($0.00)	$0.00	0.6%	$0.00	$0.01	0.8%
Gas	RICE	($0.00)	($0.00)	0.1%	($0.00)	$0.00	0.4%
Gas	Steam	($0.05)	($0.03)	2.2%	($0.03)	$0.03	2.3%
Municipal Waste	RICE	$0.00	$0.00	0.1%	$0.01	$0.01	0.2%
Oil	CC	$0.00	$0.00	0.0%	$0.00	$0.00	0.1%
Oil	CT	$0.00	($0.00)	0.2%	($0.00)	$0.00	0.1%
Oil	RICE	$0.00	$0.00	0.0%	$0.00	$0.00	0.1%
Oil	Steam	$0.00	$0.00	0.0%	$0.00	$0.01	0.1%
Other	Solar	$0.00	$0.00	0.2%	$0.00	$0.00	0.2%
Other	Steam	($0.00)	($0.00)	0.7%	($0.00)	($0.00)	0.3%
Uranium	Steam	$0.00	$0.00	1.7%	$0.00	$0.00	0.2%
Water	Hydro	$0.00	$0.00	0.0%	$0.00	$0.00	0.0%
Wind	Wind	$0.01	$0.01	2.7%	$0.39	$0.39	5.2%
Total		($0.14)	$0.98	100.0%	$0.22	$1.75	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 3-125 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 six months of 2021, when using unadjusted cost-based offers, $0.22 per MWh of the PJM day-ahead load-weighted, average LMP was attributable to markup. In the first six months of 2021, the peak markup component was highest in February, $2.13 per MWh using unadjusted cost-based offers.

Table 3-125 Monthly markup components of day-ahead (Unadjusted), load-weighted LMP: January 2020 through June 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)	($0.42)	($0.25)	($0.56)
Feb	($0.23)	($0.08)	($0.39)	($0.35)	$2.13	($2.90)
Mar	($0.21)	($0.19)	($0.23)	$0.62	$0.55	$0.70
Apr	($0.27)	($0.19)	($0.36)	$0.36	$0.83	($0.19)
May	($0.19)	$0.17	($0.52)	$0.85	$0.91	$0.78
Jun	$0.07	$0.39	($0.33)	$0.44	$0.61	$0.24
Jul	($0.54)	($0.41)	($0.72)			
Aug	$0.07	$0.70	($0.59)			
Sep	($0.01)	$0.55	($0.63)			
Oct	$0.15	$0.48	($0.21)			
Nov	($0.22)	$0.28	($0.70)			
Dec	$0.13	$0.37	($0.12)			
Total	($0.11)	$0.19	($0.43)	$0.22	$0.80	($0.37)

Table 3-126 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 six months of 2021, when using adjusted cost-based offers, $1.75 per MWh of the PJM day-ahead, load-weighted, average LMP was attributable to markup. In the first six months of 2021, the peak markup component was highest in February, $4.51 per MWh using adjusted cost-based offers.

Table 3-126 Monthly markup components of day-ahead (Adjusted), load-weighted, LMP: January 2020 through June 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	$1.11	$1.22	$1.02
Feb	$0.99	$1.17	$0.83	$2.07	$4.51	($0.42)
Mar	$0.96	$1.02	$0.90	$1.77	$1.72	$1.82
Apr	$0.70	$0.91	$0.47	$1.62	$1.97	$1.22
May	$0.72	$1.00	$0.47	$2.24	$2.25	$2.23
Jun	$1.04	$1.35	$0.67	$1.74	$1.90	$1.55
Jul	$0.65	$0.75	$0.51			
Aug	$1.14	$1.77	$0.48			
Sep	$0.95	$1.50	$0.34			
Oct	$1.12	$1.37	$0.84			
Nov	$0.89	$1.29	$0.52			
Dec	$1.49	$1.68	$1.29			
Total	$1.01	$1.29	$0.70	$1.75	$2.27	$1.20

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 3-127. The markup component of annual average day-ahead price using adjusted cost-based offers is shown for each zone in Table 3-128. The smallest zonal all hours average markup component using adjusted cost-based offers for the first six months of 2021 was in the ATSI Zone, $1.12 per MWh, while the highest was in the BGE Control Zone, $2.36 per MWh. The smallest zonal on peak average markup using adjusted cost-based offers was in the ATSI Control Zone, $1.27 per MWh, while the highest was in the BGE Control Zone, $3.64 per MWh.

Table 3-127 Day-ahead, average, zonal markup component (Unadjusted): January through June, 2020 and 2021

	2020 (Jan - Jun)			2021 (Jan - Jun)		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
ACEC	$0.09	$0.25	($0.06)	$0.20	$0.37	$0.04
AEP	($0.30)	($0.10)	($0.51)	$0.21	$0.81	($0.40)
APS	($0.25)	($0.03)	($0.47)	$0.26	$1.00	($0.49)
ATSI	($0.24)	($0.05)	($0.44)	($0.49)	($0.31)	($0.67)
BGE	($0.27)	$0.10	($0.65)	$0.91	$2.34	($0.53)
COMED	($0.23)	$0.01	($0.49)	$0.37	$1.07	($0.36)
DAY	($0.12)	$0.24	($0.51)	$0.25	$0.80	($0.34)
DOM	($0.39)	($0.28)	($0.49)	$0.23	$1.02	($0.54)
DPL	$0.14	$0.32	($0.04)	$0.16	$0.07	$0.26
DUKE	$0.07	$0.64	($0.53)	$0.27	$0.97	($0.45)
DUQ	($0.31)	($0.14)	($0.49)	($0.18)	$0.05	($0.42)
EKPC	($0.12)	$0.26	($0.50)	$0.31	$1.31	($0.65)
JCPLC	$0.05	$0.19	($0.11)	$0.21	$0.42	($0.00)
MEC	$0.08	$0.23	($0.07)	$0.36	$0.72	($0.03)
OVEC	$0.05	$0.03	$0.10	($0.26)	($0.21)	($0.33)
PE	$0.07	$0.25	($0.15)	$0.12	$0.56	($0.36)
PECO	$0.09	$0.25	($0.08)	$0.30	$0.47	$0.12
PEPCO	($0.40)	($0.24)	($0.57)	$0.62	$1.70	($0.50)
PPL	$0.86	$1.18	$0.52	$0.34	$0.64	$0.03
PSEG	$0.06	$0.21	($0.11)	$0.15	$0.33	($0.04)
REC	$0.12	$0.37	($0.15)	($0.00)	$0.24	($0.26)

Table 3-128 Day-ahead, average, zonal markup component (Adjusted): January through June, 2020 and 2021

	2020 (Jan - Jun)			2021 (Jan - Jun)		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
ACEC	$1.20	$1.38	$1.02	$1.76	$2.00	$1.53
AEP	$0.85	$1.04	$0.66	$1.71	$2.26	$1.15
APS	$0.88	$1.13	$0.62	$1.80	$2.47	$1.11
ATSI	$0.91	$1.11	$0.68	$1.12	$1.27	$0.96
BGE	$0.85	$1.21	$0.49	$2.36	$3.64	$1.08
COMED	$0.87	$1.12	$0.60	$1.85	$2.51	$1.15
DAY	$1.04	$1.38	$0.68	$1.84	$2.34	$1.30
DOM	$0.73	$0.87	$0.58	$1.76	$2.40	$1.13
DPL	$1.23	$1.41	$1.05	$1.63	$1.53	$1.74
DUKE	$1.16	$1.67	$0.64	$1.77	$2.39	$1.12
DUQ	$0.79	$0.98	$0.60	$1.34	$1.53	$1.15
EKPC	$1.00	$1.34	$0.67	$1.86	$2.76	$0.98
JCPLC	$1.18	$1.34	$0.99	$1.79	$2.04	$1.53
MEC	$1.20	$1.37	$1.01	$1.83	$2.17	$1.46
OVEC	$1.15	$1.15	$1.15	$1.38	$1.39	$1.36
PE	$1.11	$1.32	$0.85	$1.64	$2.08	$1.16
PECO	$1.19	$1.38	$1.00	$1.85	$2.07	$1.62
PEPCO	$0.76	$0.96	$0.56	$2.15	$3.10	$1.16
PPL	$1.90	$2.23	$1.55	$1.83	$2.14	$1.52
PSEG	$1.16	$1.32	$0.98	$1.72	$1.95	$1.48
REC	$1.20	$1.43	$0.93	$1.51	$1.75	$1.25

Markup by Day-Ahead Price Levels

Table 3-129 and Table 3-130 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 3-129 Average, day-ahead markup component (By LMP category, unadjusted): January through June, 2020 and 2021

	2020 (Jan - Jun)		2021 (Jan - Jun)	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $10	$0.00	1.5%	$0.00	0.0%
$10 to $15	($0.05)	19.0%	($0.00)	0.1%
$15 to $20	($0.22)	47.8%	$0.05	16.5%
$20 to $25	$0.03	23.4%	($0.10)	32.2%
$25 to $50	$0.11	8.2%	$0.26	45.9%
$50 to $75	$0.00	0.1%	($0.12)	3.4%
$75 to $100	$0.00	0.0%	$0.08	0.8%
$100 to $125	$0.00	0.0%	$0.00	0.5%
$125 to $150	$0.00	0.0%	($0.03)	0.4%
>= $150	$0.00	0.0%	$0.09	0.2%

Table 3-130 Average, day-ahead markup component (By LMP category, adjusted): January through June, 2020 and 2021

	2020 (Jan - Jun)		2021 (Jan - Jun)	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $10	$0.01	1.5%	$0.00	0.0%
$10 to $15	$0.09	19.0%	($0.00)	0.1%
$15 to $20	$0.36	47.8%	$0.21	16.5%
$20 to $25	$0.34	23.4%	$0.34	32.2%
$25 to $50	$0.18	8.2%	$1.01	45.9%
$50 to $75	$0.00	0.1%	($0.04)	3.4%
$75 to $100	$0.00	0.0%	$0.10	0.8%
$100 to $125	$0.00	0.0%	$0.03	0.5%
$125 to $150	$0.00	0.0%	($0.00)	0.4%
>= $150	$0.00	0.0%	$0.10	0.2%

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:[176]

$$\frac{HHI}{\varepsilon} = \frac{P - MC}{P}$$

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 higher prices on customers. The Lerner Index is a measure of market power that

176 *See* Tirole, Jean. *The Theory of Industrial Organization*, MIT (1988), Chapter 5: Short-Run Price Competition.

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.[177] 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:[178]

$$\frac{HHI}{\varepsilon} = \frac{0.1}{0.2} = \frac{P - MC}{P} = 50\%$$

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 $30.74 per MWh and an average HHI of 751 in the first six months of 2021, average PJM prices would theoretically range from $38 to $49 per MWh using the elasticity range of -0.2 to -0.4.[179] 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 $30.62 per MWh, and markups, at -0.4 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.

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 3-131 categorizes day-ahead and real-time marginal unit intervals by markup level and TPS test status. In the first six months of 2021, 3.8 percent of real-time marginal unit intervals and 3.4 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 3-131 Percent of real-time marginal unit intervals with markup and local market power: January through June, 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	38.2%	8.0%	46.2%	38.5%	9.1%	47.6%
Zero Markup	17.2%	5.3%	22.5%	16.2%	8.5%	24.7%
$0 to $5	22.2%	2.6%	24.8%	19.6%	2.8%	22.4%
$5 to $10	2.0%	0.3%	2.3%	2.4%	0.5%	2.8%
$10 to $15	0.8%	0.2%	1.0%	0.7%	0.1%	0.8%
$15 to $20	1.9%	0.1%	1.9%	0.4%	0.1%	0.4%
$20 to $25	0.3%	0.1%	0.4%	0.2%	0.1%	0.3%
$25 to $50	0.3%	0.1%	0.4%	0.5%	0.2%	0.7%
$50 to $75	0.5%	0.0%	0.5%	0.1%	0.0%	0.1%
$75 to $100	0.0%	0.0%	0.0%	0.1%	0.0%	0.1%
Above $100	0.0%	0.0%	0.0%	0.1%	0.1%	0.1%
Total Positive Markup	27.9%	3.4%	31.3%	23.9%	3.8%	27.7%
Total	83.3%	16.7%	100.0%	78.6%	21.4%	100.0%

The markup of marginal units was zero or negative in 72.3 percent of real-time marginal unit intervals and 68.7 percent of day-ahead marginal unit intervals in the first six months of 2021. Pivotal suppliers in the aggregate market also set prices with high markups in the first six 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.

177 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>.

178 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.

179 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.