Capacity Market

Each organization serving PJM load must meet its capacity obligations through the PJM Capacity Market, where load serving entities (LSEs) must pay the locational capacity price for their zone. LSEs can also construct generation and offer it into the capacity market, enter into bilateral contracts, develop demand resources and energy efficiency (EE) resources and offer them into the capacity market, or construct transmission upgrades and offer them into the capacity market.

The Market Monitoring Unit (MMU) analyzed market structure, participant conduct and market performance in the PJM Capacity Market, including supply, demand, concentration ratios, pivotal suppliers, volumes, prices, outage rates and reliability.[1] The conclusions are a result of the MMU's evaluation of the last Base Residual Auction, for the 2021/2022 Delivery Year.

Table 5-1 The capacity market results were not competitive

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

- The aggregate market structure was evaluated as not competitive. For almost all auctions held from 2007 to the present, the PJM region failed the three pivotal supplier test (TPS), which is conducted at the time of the auction.[2] Structural market power is endemic to the capacity market.
- The local market structure was evaluated as not competitive. For almost every auction held, all LDAs have failed the TPS test, which is conducted at the time of the auction.[3]
- Participant behavior was evaluated as not competitive in the 2021/2022 RPM Base Residual Auction. Market power mitigation measures were applied when the capacity market seller failed the market power test for the auction, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, would increase the market clearing price. But the net CONE times B offer cap under the capacity performance design, in the absence of 30 performance assessment hours, exceeds the competitive level and should be reevaluated for each BRA. In the 2021/2022 RPM Base Residual Auction, some participants' offers were above the competitive level. The MMU recognizes that these market participants followed the capacity market rules by offering at less than the stated offer cap of Net CONE times B. But Net CONE times B is not a competitive offer when the expected number of performance assessment intervals is zero or a very small number and the nonperformance charge rate is defined as Net CONE/30. Under these circumstances, a competitive offer, under the logic defined in PJM's capacity performance filing, is net ACR. That is the way in which most market participants offered in this and prior capacity performance auctions.
- Market performance was evaluated as not competitive based on the 2021/2022 RPM Base Residual Auction. Although structural market power exists in the Capacity Market, a competitive outcome can result from the application of market power mitigation rules. The outcome of the 2021/2022 RPM Base Residual Auction was not competitive as a result of participant behavior which was not competitive, specifically offers which exceeded the competitive level.
- Market design was evaluated as mixed because while there are many positive features of the Reliability Pricing Model (RPM) design and the capacity performance modifications to RPM, there are several features of the RPM design which still threaten competitive outcomes. These include the definition of DR which permits inferior products to substitute for capacity, the replacement capacity issue, the definition of unit offer parameters, the inclusion of imports which are not substitutes for internal capacity resources, and the definition of the default offer cap.

1 The values stated in this report for the RTO and LDAs refer to the aggregate level including all nested LDAs unless otherwise specified. For example, RTO values include the entire PJM market and all LDAs. Rest of RTO values are RTO values net of nested LDA values.
2 In the 2008/2009 RPM Third Incremental Auction, 18 participants in the RTO market passed the TPS test. In the 2018/2019 RPM Second Incremental Auction, 35 participants in the RTO market passed the test.
3 In the 2012/2013 RPM Base Residual Auction, six participants included in the incremental supply of EMAAC passed the TPS test. In the 2014/2015 RPM Base Residual Auction, seven participants in the incremental supply in MAAC passed the TPS test. In the 2021/2022 RPM First Incremental Auction, two participants in the incremental supply in EMAAC passed the TPS test. In the 2021/2022 RPM Second Incremental Auction, two participants in the incremental supply in EMAAC passed the TPS test.

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- PJM did not run the 2022/2023 Base Residual Auction in May 2019, the 2023/2024 Base Residual Auction in May 2020, or the 2022/2023 First Incremental Auction in September 2020 because the capacity market design was found to be not just and reasonable by FERC and a final market design had not been approved.

Overview

RPM Capacity Market

Market Design

The Reliability Pricing Model (RPM) Capacity Market is a forward-looking, annual, locational market, with a must offer requirement for Existing Generation Capacity Resources and mandatory participation by load, with performance incentives, that includes clear market power mitigation rules and that permits the direct participation of demand-side resources.[4]

Under RPM, capacity obligations are annual.[5] Base Residual Auctions (BRA) are held for delivery years that are three years in the future. First, Second and Third Incremental Auctions (IA) are held for each delivery year.[6] First, Second, and Third Incremental Auctions are conducted 20, 10, and three months prior to the delivery year.[7] A Conditional Incremental Auction may be held if there is a need to procure additional capacity resulting from a delay in a planned large transmission upgrade that was modeled in the BRA for the relevant delivery year.[8]

The 2020/2021 RPM Third Incremental Auction and the 2021/2022 RPM Second Incremental Auction were conducted in the first nine months of 2020.

RPM prices are locational and may vary depending on transmission constraints and local supply and demand conditions.[9] Existing generation capable of qualifying as a capacity resource must be offered into RPM auctions, except for resources owned by entities that elect the fixed resource requirement (FRR) option. Participation by LSEs is mandatory, except for those entities that elect the FRR option. There is an administratively determined demand curve that defines scarcity pricing levels and that, with the supply curve derived from capacity offers, determines market prices in each BRA. RPM rules provide performance incentives for generation, including the requirement to submit generator outage data and the linking of capacity payments to the level of unforced capacity, and the performance incentives have been strengthened significantly under the Capacity Performance modifications to RPM. Under RPM there are explicit market power mitigation rules that define the must offer requirement, that define structural market power based on the marginal cost of capacity, that define offer caps, that define the minimum offer price, and that have flexible criteria for competitive offers by new entrants. Market power mitigation is effective only when these definitions are up to date and accurate. Demand resources and energy efficiency resources may be offered directly into RPM auctions and receive the clearing price without mitigation.

Market Structure

- **RPM Installed Capacity.** In the first nine months of 2020, RPM installed capacity decreased 788.7 MW or 0.4 percent, from 184,722.8 MW on January 1 to 183,934.17 MW on September 30. Installed capacity includes net capacity imports and exports and can vary on a daily basis.
- **RPM Installed Capacity by Fuel Type.** Of the total installed capacity on September 30, 2020, 45.7 percent was gas; 27.0 percent was coal; 17.6 percent was nuclear; 4.8 percent was hydroelectric; 3.4 percent was oil; 0.7 percent was wind; 0.4 percent was solid waste; and 0.5 percent was solar.
- **Market Concentration.** In the 2021/2022 RPM Second Incremental Auction, two participants in the EMAAC LDA market passed the TPS test.[10] Offer caps were applied to all sell offers for resources which were subject to mitigation when the capacity market seller did not pass the test,

4 The terms *PJM Region*, *RTO Region* and *RTO* are synonymous in this report and include all capacity within the PJM footprint.
5 Effective for the 2020/2021 and subsequent delivery years, the RPM market design incorporated seasonal capacity resources. Summer period and winter period capacity must be matched either with commercial aggregation or through the optimization in equal MW amounts in the LDA or the lowest common parent LDA.
6 See 126 FERC ¶ 61,275 at P 86 (2009).
7 See Letter Order, FERC Docket No. ER10-366-000 (January 22, 2010).
8 See 126 FERC ¶ 61,275 at P 88 (2009). There have been no Conditional Incremental Auctions.
9 Transmission constraints are local capacity import capability limitations (low capacity emergency transfer limit (CETL) margin over capacity emergency transfer objective (CETO)) caused by transmission facility limitations, voltage limitations or stability limitations.
10 There are 27 Locational Deliverability Areas (LDAs) identified to recognize locational constraints as defined in "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Schedule 10.1. PJM determines, in advance of each BRA, whether the defined LDAs will be modeled in the given delivery year using the rules defined in OATT Attachment DD § 5.10(a)(ii).

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the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, increased the market clearing price.[11] [12] [13]

- **Imports and Exports.** Of the 4,470.4 MW of imports in the 2021/2022 RPM Base Residual Auction, 4,051.8 MW cleared. Of the cleared imports, 1,909.9 MW (47.1 percent) were from MISO.
- **Demand-Side and Energy Efficiency Resources.** Capacity in the RPM load management programs was 10,586.0 MW for June 1, 2020, as a result of cleared capacity for demand resources and energy efficiency resources in RPM auctions for the 2020/2021 delivery year (13,015.2 MW) less purchases of replacement capacity (2,429.2 MW).

Market Conduct

- **2021/2022 RPM Second Incremental Auction.** Of the 276 generation resources that submitted Capacity Performance offers, the MMU calculated unit specific offer caps for zero generation resources (0.0 percent).

Market Performance

- The 2020/2021 RPM Third Incremental Auction and the 2021/2022 RPM Second Incremental Auction were conducted in the first nine months of 2020.[14] The weighted average capacity price for the 2019/2020 Delivery Year is $109.82 per MW-day, including all RPM auctions for the 2019/2020 Delivery Year. The weighted average capacity price for the 2020/2021 Delivery Year is $111.05 per MW-day, including all RPM auctions for the 2020/2021 Delivery Year.
- For the 2020/2021 Delivery Year, RPM annual charges to load are $7.0 billion.
- In the 2021/2022 RPM Base Residual Auction, the market performance was determined to be not competitive as a result of noncompetitive offers that affected market results.

Reliability Must Run Service

- Of the seven companies (23 units) that have provided RMR service, two companies (seven units) filed to be paid for RMR service under the deactivation avoidable cost rate (DACR), the formula rate. The other five companies (16 units) filed to be paid for RMR service under the cost of service recovery rate.

Generator Performance

- **Forced Outage Rates.** The average PJM EFORd in the first nine months of 2020 was 6.3 percent, an increase from 6.0 percent in the first nine months of 2019.[15]
- **Generator Performance Factors.** The PJM aggregate equivalent availability factor in the first nine months of 2020 was 86.8 percent, an increase from 85.2 percent in the first nine months of 2019.

Recommendations[16]

Definition of Capacity

- The MMU recommends the enforcement of a consistent definition of capacity resource. The MMU recommends that the requirement to be a physical resource be enforced and enhanced. The requirement to be a physical resource should apply at the time of auctions and should also constitute a commitment to be physical in the relevant delivery year. The requirement to be a physical resource should be applied to all resource

11 See OATT Attachment DD § 6.5.
12 Prior to November 1, 2009, existing DR and EE resources were subject to market power mitigation in RPM Auctions. See 129 FERC ¶ 61,081 at P 30 (2009).
13 Effective January 31, 2011, the RPM rules related to market power mitigation were changed, including revising the definition for Planned Generation Capacity Resource and creating a new definition for Existing Generation Capacity Resource for purposes of the must offer requirement and market power mitigation, and treating a proposed increase in the capability of a generation capacity resource the same in terms of mitigation as a Planned Generation Capacity Resource. See 134 FERC ¶ 61,065 (2011).
14 FERC granted PJM's request for waiver of its Open Access Transmission Tariff to delay the 2022/2023 RPM Base Residual Auction from May 2019 to August 2019. See 164 FERC ¶ 61,153 (2018). FERC subsequently denied PJM's motion seeking clarification of the June 29, 2018, Order (163 FERC ¶ 61,236) and directed PJM not to run the 2022/2023 BRA in August 2019. See 168 FERC ¶ 61,051 (2019).
15 The generator performance analysis includes all PJM capacity resources for which there are data in the PJM generator availability data systems (GADS) database. Data was downloaded from the PJM GADS database on October 23, 2020. EFORd data presented in state of the market reports may be revised based on data submitted after the publication of the reports as generation owners may submit corrections at any time with permission from PJM GADS administrators.
16 The MMU has identified serious market design issues with RPM and the MMU has made specific recommendations to address those issues. These recommendations have been made in public reports. See Table 5-2.

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types, including planned generation, demand resources and imports.[17] [18] (Priority: High. First reported 2013. Status: Not adopted.)

- The MMU recommends that DR providers be required to have a signed contract with specific customers for specific facilities for specific levels of DR at least six months prior to any capacity auction in which the DR is offered. (Priority: High. First reported 2016. Status: Not adopted.)

Market Design and Parameters

- The MMU recommends that the test for determining modeled Locational Deliverability Areas (LDAs) in RPM be redefined. A detailed reliability analysis of all at risk units should be included in the redefined model. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that the net revenue calculation used by PJM to calculate the net Cost of New Entry (CONE) VRR parameter reflect the actual flexibility of units in responding to price signals rather than using assumed fixed operating blocks that are not a result of actual unit limitations.[19] [20] The result of reflecting the actual flexibility is higher net revenues, which affect the parameters of the RPM demand curve and market outcomes. (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that energy efficiency resources (EE) not be included on the supply side of the capacity market, because PJM's load forecasts now account for future EE, unlike the situation when EE was first added to the capacity market. However, the MMU recommends that the PJM load forecast method should be modified so that EE impacts immediately affect the forecast without the long lag times incorporated in the current forecast method. If EE is not included on the supply side, there is no reason to have an add back mechanism. If EE remains on the supply side, the implementation of the EE add back mechanism should be modified to ensure that market clearing prices are not affected. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that PJM reduce the number of incremental auctions to a single incremental auction held three months prior to the start of the delivery year and reevaluate the triggers for holding conditional incremental auctions. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM offer to sell back capacity in incremental auctions only at the BRA clearing price for the relevant delivery year. (Priority: Medium. First reported 2017. Status: Not adopted.)
- The MMU recommends changing the RPM solution method to explicitly incorporate the cost of make whole payments in the objective function. (Priority: Medium. First reported 2014. Status: Not adopted.)
- The MMU recommends that PJM clear the capacity market based on nodal capacity resource locations and the characteristics of the transmission system consistent with the actual electrical facts of the grid. The current nested LDA structure used in the capacity market does not adequately represent all the capacity transfers that are feasible among LDAs. Absent a fully nodal capacity market clearing process, the MMU recommends that PJM use a nonnested model for all LDAs and specify a VRR curve for each LDA separately. Each LDA requirement should be met with the capacity resources located within the LDA and exchanges from neighboring LDAs up to the transmission limit. LDAs should price separate if that is the result of the LDA supply curves and the transmission constraints. (Priority: Medium. First reported 2017. Status: Not adopted.)
- The MMU recommends that the maximum price on the VRR curve be defined as net CONE. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that the Fixed Resource Requirement (FRR) rules, including obligations and performance requirements, be reviewed. (Priority: Medium. First reported 2019. Status: Not adopted.)

17 See also Comments of the Independent Market Monitor for PJM, Docket No. ER14-503-000 (December 20, 2013).
18 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2019," <http://www.monitoringanalytics.com/reports/Reports/2019/IMM_Analysis_of_Replacement_Capacity_for_RPM_Commitments_June_1_2007_to_June_1_2019_20190913.pdf> (September 13, 2019).
19 See PJM Interconnection, L.L.C., Docket No. ER12-513-000 (December 1, 2011) ("Triennial Review").
20 See the *2019 State of the Market Report for PJM*, Volume 2, Section 7: Net Revenue.

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Offer Caps, Offer Floors, and Must Offer

- The MMU recommends use of the Sustainable Market Rule (SMR) in order to protect competition in the capacity market from nonmarket revenues.[21] (Priority: High. First reported 2016. Status: Not adopted.)
- The MMU recommends that, as part of the MOPR unit specific standard of review, all projects be required to use the same basic modeling assumptions. That is the only way to ensure that projects compete on the basis of actual costs rather than on the basis of modeling assumptions.[22] (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that modifications to existing resources not be treated as new resources for purposes of market power related offer caps or MOPR offer floors. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends that the RPM market power mitigation rule be modified to apply offer caps in all cases when the three pivotal supplier test is failed and the sell offer is greater than the offer cap. This will ensure that market power does not result in an increase in make whole payments. (Priority: Medium. First reported 2017. Status: Not adopted.)
- The MMU recommends that the offer cap for capacity resources be defined as the net avoidable cost rate (ACR) of each unit so that the clearing prices are a result of such net ACR offers, consistent with the fundamental economic logic for a competitive offer of a CP resource. (Priority: High. First reported 2017. Status: Not adopted.)
- The MMU recommends that PJM develop a process for calculating a forward looking estimate for the expected number of Performance Assessment Intervals (H) to use in calculating the Market Seller Offer Cap (MSOC). The MMU recommends that the Nonperformance Charge Rate be left at its current level. The MMU recommends that PJM develop a forward looking estimate for the Balancing Ratio (B) during Performance Assessment Intervals (PAIs) to use in calculating the MSOC. Both H and B parameters should be included in the annual review of planning parameters for the Base Residual Auction, and should incorporate the actual observed reserve margins, and other assumptions consistent with the annual IRM study. (Priority: High. First reported 2017. Status: Not adopted.)
- The MMU recommends that capacity market sellers be required to request the use of minimum MW quantities greater than 0 MW (inflexible sell offer segments) and that the requests should only be permitted for defined physical reasons. (Priority: Medium. First reported 2018. Status: Not adopted.)

Performance Incentive Requirements of RPM

- The MMU recommends that any unit which is not capable of supplying energy consistent with its day-ahead offer which should equal its ICAP, reflect an appropriate outage. (Priority: Medium. First reported 2009. Status: Not adopted.)
- The MMU recommends that retroactive replacement transactions associated with a failure to perform during a PAI not be allowed and that, more generally, retroactive replacement capacity transactions not be permitted. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that there be an explicit requirement that capacity resource offers in the day-ahead energy market be competitive, where competitive is defined to be the short run marginal cost of the units. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that Capacity Performance resources be required to perform without excuses. Resources that do not perform should not be paid regardless of the reason for nonperformance. (Priority: High. First reported 2019. Status: Not adopted.)
- The MMU recommends that the market data posting rules be modified to allow the disclosure of expected performance, actual performance,

21 Brief of the Independent Market Monitor for PJM, Docket No. EL16-49, ER18-1314-000,-001; EL18-178 (October 2, 2018).
22 See 143 FERC ¶ 61,090 (2013) ("We encourage PJM and its stakeholders to consider, for example, whether the unit-specific review process would be more effective if PJM requires the use of common modeling assumptions for establishing unit-specific offer floors while, at the same time, allowing sellers to provide support for objective, individual cost advantages. Moreover, we encourage PJM and its stakeholders to consider these modifications to the unit-specific review process together with possible enhancements to the calculation of Net CONE."); see also, Comments of the Independent Market Monitor for PJM, Docket No. ER13-535-001 (March 25, 2013); Complaint of the Independent Market Monitor for PJM v. Unnamed Participant, Docket No. EL12-63-000 (May 1, 2012); Motion for Clarification of the Independent Market Monitor for PJM, Docket No. ER11-2875-000, et al. (February 17, 2012); Protest of the Independent Market Monitor for PJM, Docket No. ER11-2875-002 (June 2, 2011); Comments of the Independent Market Monitor for PJM, Docket Nos. EL11-20 and ER11-2875 (March 4, 2011).

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shortfall and bonus MW during a PAI by area without the requirement that more than three market participants' data be aggregated for posting. (Priority: Low. First reported 2019. Status: Not adopted.)

Capacity Imports and Exports

- The MMU recommends that all capacity imports be required to be deliverable to PJM load prior to the relevant delivery year to ensure that they are full substitutes for internal, physical capacity resources. Pseudo ties alone are not adequate to ensure deliverability. (Priority: High. First reported 2016. Status: Not adopted.)
- The MMU recommends that all costs incurred as a result of a pseudo tied unit be borne by the unit itself and included as appropriate in unit offers in the capacity market. (Priority: High. First reported 2016. Status: Not adopted.)
- The MMU recommends clear, explicit and detailed rules that define the conditions under which PJM will and will not recall energy from PJM capacity resources and prohibit new energy exports from PJM capacity resources. The MMU recommends that those rules define the conditions under which PJM will purchase emergency energy while at the same time not recalling energy exports from PJM capacity resources. PJM has modified these rules, but the rules need additional clarification and operational details. (Priority: Low. First reported 2010. Status: Partially adopted.)

Deactivations/Retirements

- The MMU recommends that the notification requirement for deactivations be extended from 90 days prior to the date of deactivation to 12 months prior to the date of deactivation and that PJM and the MMU be provided 60 days rather than 30 days to complete their reliability and market power analyses. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends that RMR units recover all and only the incremental costs, including incremental investment costs, required by the RMR service that the unit owner would not have incurred if the unit owner had deactivated its unit as it proposed. Customers should bear no responsibility for paying previously incurred costs, including a return on or of prior investments. (Priority: Low. First reported 2010. Status: Not adopted.)
- The MMU recommends elimination of the cost of service recovery rate in OATT Section 119, and that RMR service should be provided under the deactivation avoidable cost rate in Part V. The MMU also recommends specific improvements to the DACR provisions. (Priority: Medium. First reported 2017. Status: Not adopted.)

Conclusion

The analysis of PJM Capacity Markets begins with market structure, which provides the framework for the actual behavior or conduct of market participants. The analysis examines participant behavior within that market structure. In a competitive market structure, market participants are constrained to behave competitively. The analysis examines market performance, measured by price and the relationship between price and marginal cost, that results from the interaction of market structure and participant behavior. Market power is and will remain endemic to the structure of the PJM Capacity Market. Nonetheless a competitive outcome can be assured by appropriate market power mitigation rules.

The MMU concludes that the 2021/2022 RPM Base Residual Auction results were not competitive as a result of offers above the competitive level by some market participants. The MMU recognizes that these market participants followed the capacity market rules by offering at less than the stated offer cap of net CONE times B. But net CONE times B is not a competitive offer when the expected number of performance assessment intervals is zero or a very small number and the nonperformance charge rate is defined as net CONE/30. Under these circumstances, a competitive offer, under the logic defined in PJM's capacity performance filing, is net ACR. That is the way in which most market participants offered in this and prior capacity performance auctions.

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The FERC approved PJM tariff defines the offer cap as net CONE times B, rather than including the full logic supporting the definition of the offer cap under the capacity performance paradigm. If the tariff had defined the offer cap consistent with PJM's filing in the capacity performance matter, the offer cap would have been net ACR rather than net CONE times B.

The MMU filed a complaint with the Commission asserting that the market seller offer cap is overstated.[23] The result of an overstated market seller offer cap is to permit the exercise of market power, as occurred in the 2021/2022 BRA. That complaint remains pending. The outcome of the complaint could have a significant and standalone impact on clearing prices in the 2022/2023 BRA.

The MMU is required to identify market issues and to report them to the Commission and to market participants. The Commission decides on any action related to the MMU's findings.

The MMU found serious market structure issues, measured by the three pivotal supplier test results in the PJM Capacity Market in the last BRA and in the first nine months of 2020. Explicit market power mitigation rules in the RPM construct only partially offset the underlying market structure issues in the PJM Capacity Market under RPM. In the 2021/2022 RPM Base Residual Auction, the default offer cap of net CONE times B exceeded the competitive offer for a number of resources. Some seasonal resources were paid additional make whole based on a failure of the market power rules to apply offer capping.

The MMU has identified serious market design issues with RPM and the MMU has made specific recommendations to address those issues.[24] [25] [26] [27] [28] [29] In 2019 and 2020, the MMU prepared a number of RPM related reports and testimony, shown in Table 5-2.

The capacity performance modifications to the RPM construct significantly improved the capacity market and addressed a number of issues that had been identified by the MMU. But significant issues remain in the PJM capacity market design.

The PJM markets have worked to provide incentives to entry and to retain capacity. PJM had excess reserves of 11,911.9 ICAP MW on June 1, 2020, and will have excess reserves of 18,401.8 ICAP MW on June 1, 2021, based on current positions.[30] A majority of capacity investments in PJM were financed by market sources.[31] Of the 41,979.4 MW of additional capacity that cleared in RPM auctions for the 2007/2008 through 2019/2020 delivery years, 32,333.9 MW (77.0 percent) were based on market funding. Of the 2,640.4 MW of additional capacity that cleared in RPM auctions for the 2020/2021 through 2021/2022 Delivery Years, 2,553.6 MW (96.7 percent) were based on market funding. Those investments were made based on the assumption that markets would be allowed to work and that inefficient units would exit.

The issue of external subsidies, particularly for economic nuclear power plants, continued to evolve. The subsidies are not part of the PJM market

23 In 2019, the MMU filed a complaint seeking an order directing PJM to update the assumptions regarding the expected number of performance assessment intervals (PAI) in calculating the default capacity market seller offer cap (MSOC). Complaint of the Independent Market Monitor for PJM, Docket No. EL19-47-000 (February 21, 2019).

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

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

26 See "Analysis of the 2020/2021 RPM Base Residual Auction," <http://www.monitoringanalytics.com/reports/Reports/2017/IMM_Analysis_of_the_20202021_RPM_BRA_20171117.pdf> (November 11, 2017).

27 See "Analysis of the 2021/2022 RPM Base Residual Auction - Revised," <http://www.monitoringanalytics.com/reports/Reports/2018/IMM_Analysis_of_the_20212022_RPM_BRA_Revised_20180824.pdf> (August 24, 2018).

28 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2017," <http://www.monitoringanalytics.com/reports/Reports/2017/IMM_Report_on_Capacity_Replacement_Activity_4_20171214.pdf> (December 14, 2017).

29 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2019," <http://www.monitoringanalytics.com/reports/Reports/2019/IMM_Analysis_of_Replacement_Capacity_for_RPM_Commitments_June_1_2007_to_June_1_2019_20190913.pdf> (September 13, 2019).

30 The calculated reserve margin for June 1, 2021, does not account for cleared buy bids that have not been used in replacement capacity transactions.

31 "2020 PJM Generation Capacity and Funding Sources 2007/2008 through 2021/2022 Delivery Years," <http://www.monitoringanalytics.com/reports/Reports/2020/IMM_2020_PJM_Generation_Capacity_and_Funding_Sources_20072008_through_20212022_DY_20200915.pdf> (September 15, 2020).

design but nonetheless threaten the foundations of the PJM Capacity Market as well as the competitiveness of PJM markets overall.

The Ohio subsidy legislation to subsidize both nuclear and coal plants and to eliminate the RPS, the Illinois ZEC legislation to subsidize the Quad Cities nuclear power plant and the requests for additional subsidies, the request in Pennsylvania to subsidize nuclear power plants, the New Jersey legislation to subsidize the Salem and Hope Creek nuclear power plants, the potential U.S. DOE proposal to subsidize coal and nuclear power plants, the request by FirstEnergy to the U.S. DOE for subsidies consistent with the DOE Grid Resilience Proposal and the specific FRR proposals for ComEd and for New Jersey, all originate from the fact that competitive markets result in the exit of uneconomic and uncompetitive generating units. Regardless of the specific rationales offered by unit owners, the proposed solution for all such generating units has been to provide out of market subsidies in order to retain such units. The proposed solution in all cases ignores the opportunity cost of subsidizing uneconomic units, which is the displacement of new resources and technologies that would otherwise be economic. These subsidies are not accurately characterized as state subsidies. These subsidies were all requested by the owners of specific uneconomic generating units in order to improve the profitability of those specific units. These subsidies were not requested to accomplish broader social goals. Broader social goals can all be met with market-based mechanisms available to all market participants on a competitive basis and without discrimination.

Subsidies are contagious. Competition in the markets could be replaced and is now being replaced by competition to receive subsidies. Similar threats to competitive markets are being discussed by unit owners in other states and the potentially precedential nature of these actions enhances the urgency of creating an effective rule to maintain competitive markets by modifying market rules to address these subsidies. Competition to receive subsidies is now a reality and is accelerating in PJM.

It is essential that any approach to the PJM markets incorporate a consistent view of how the preferred market design is expected to provide competitive results in a sustainable market design over the long run. A sustainable market design means a market design that results in appropriate incentives to competitive market participants to retire units and to invest in new units over time such that reliability is ensured as a result of the functioning of the market. The MMU calls this approach the Sustainable Market Rule (SMR).[32] The SMR is fully consistent with the renewables targets of many states in the PJM footprint. The SMR is also consistent with incorporating economic nuclear power plants in the capacity market.

A sustainable competitive wholesale power market must recognize three salient structural elements: state nonmarket revenues for renewable energy; a significant level of generation resources subject to cost of service regulation; and the structure and performance of the existing market based generation fleet.

Subsidies to specific resources that are uneconomic as a result of competition are an effort to reverse market outcomes with no commitment to a regulatory model and no attempt to mitigate negative impacts on competition. The unit specific subsidy model is inconsistent with the PJM market design and inconsistent with the market paradigm and constitutes a significant threat to both.

The states have authority over their generation resources and can choose to remain in PJM capacity markets or to create FRR entities. The existing FRR approach remains an option for utilities with regulated revenues based on cost of service rates, including both privately and publicly owned (including public power entities and electric cooperatives) utilities. Such regulated utilities have had and continue to have the ability to opt out of the capacity market and provide their own capacity. As made clear in recent analyses of FRR options in Illinois, Maryland, New Jersey and Ohio, the FRR approach is likely to lead to significant increases in payments by customers.[33] The existing FRR rules

32 The MMU filed several comments as well as a proposal summary in the Capacity Market Investigation focused on the Sustainable Market Rule (SMR) in Docket Nos. ER18-1314-000, -001, EL16-49-000, and EL18-178-000 (October 2, 2018; October 31, 2018; November 6, 2018). MMU filings are located at the Monitoring Analytics website at <http://www.monitoringanalytics.com/Filings/2018.shtml>.

33 The MMU has posted several reports regarding the creation of FRRs. "Potential Impacts of the Creation of a ComEd FRR," (December 18, 2019). <http://www.monitoringanalytics.com/reports/Reports/2019/IMM_Potential_Impacts_of_the_Creation_of_a_ComEd_FRR_20191218.pdf>. "Potential Impacts of the Creation of Maryland FRRs," (April 16, 2020). <http://www.monitoringanalytics.com/reports/Reports/2020/IMM_Potential_Impacts_of_the_Creation_of_Maryland_FRRs_20200416.pdf>. "Potential Impacts of the Creation

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were created in 2007 primarily for the specific circumstances of AEP as part of the original RPM capacity market design settlement. The FRR rules should be revised and updated to ensure that the rules reflect current market realities and that FRR entities do not unfairly take advantage of those customers paying for capacity in the PJM capacity market.

Recent FRR proposals in Illinois for the ComEd Zone and in New Jersey are primarily nuclear subsidy programs that would increase nuclear subsidies well beyond the ZECs rules currently in place in both states while also providing for payments to some renewable resources at above market prices.[34] The MMU has prepared reports with analysis on the potential impacts of states pursuing the FRR option. In separate reports for Illinois, Maryland, New Jersey and Ohio, the cost impacts of the state choosing the FRR option are computed under different FRR capacity price assumptions and different assumptions regarding the composition of the FRR service area.[35] [36] [37] [38] Additionally, the impact on the remaining PJM capacity market footprint is computed for each scenario. In all but a few scenarios the MMU finds that the FRR leads to higher costs for load included in the FRR service area. In all scenarios the MMU finds that prices in what remains of the PJM capacity market would be significantly lower.

Given that states have increasingly aggressive renewable energy targets, a core goal of a competitive market design should be to ensure that the resources required to provide reliability receive appropriate competitive market incentives for entry and for ongoing investment and for exit when uneconomic. A significant level of renewable resources, operating with zero or near zero marginal costs, will result in very low energy prices. Since renewable resources are intermittent, the contribution of renewables to meeting reliability targets must be analyzed carefully to ensure that the capacity value is calculated correctly. PJM is considering the application of the Effective Load Carrying Capability (ELCC) approach to defining a dynamic and market based method for determining the capacity contribution of intermittent resources. ELCC would be an advance over the current approach to discounting the reliability contribution of intermittent resources, if done correctly. But implementing ELCC incorrectly, based on average rather than marginal values and locking in values regardless of market realities, would be a significant mistake and create new issues for the PJM capacity markets. The results could be degraded reliability, favoring old technologies over new technologies, and the inefficient displacement of thermal resources. It is essential to not build in a bad market design from the beginning as such designs gain momentum and gain entrenched supporters among the beneficiaries.

In order to attract and retain adequate resources for the reliable operation of the energy market, revenues from PJM energy, ancillary services and capacity markets must be adequate for those resources. That adequacy requires a capacity market. The capacity market plays the essential role of equilibrating the revenues necessary to incent competitive entry and exit of the resources needed for reliability, with the revenues from the energy market that are directly affected by nonmarket sources.

Price suppression below the competitive level in the capacity market should not be acceptable and is not consistent with a competitive market design. Harmonizing means that the integrity of each paradigm is maintained and respected. Harmonizing permits nonmarket resources to have an unlimited impact on energy markets and energy prices. Harmonizing means designing a capacity market to account for these energy market impacts, clearly limiting the impact of nonmarket revenues on the capacity market and ensuring competitive outcomes in the capacity market and thus in the entire market.

The expected impact of the SMR design on the offers and clearing of renewable resources and nuclear plants would be from zero to insignificant.

of New Jersey FRRs," (May 13, 2020). <http://www.monitoringanalytics.com/reports/Reports/2020/IMM_Potential_Impacts_of_the_Creation_of_New_Jersey_FRRS_20200513.pdf>. "Potential Impacts of the Creation of Ohio FRRs," (July 17, 2020). <http://www.monitoringanalytics.com/reports/Reports/2020/IMM_Potential_Impacts_of_the_Creation_of%20Ohio_FRRs_20200717.pdf>.

34 *In the Matter of the Investigation of Resource Adequacy Alternatives*, New Jersey Board of Public Utilities, Docket No. EO20030203. Monitoring Analytics, LLC Comments, <http://www.monitoringanalytics.com/filings/2020/IMM_Comments_Docket_No_EO20030203_20200520.pdf> (May 20, 2020). Monitoring Analytics, LLC, Reply Comments <http://www.monitoringanalytics.com/filings/2020/IMM_Reply_Comments_Docket_No_EO20030203_20200624.pdf>. (June 24, 2020). Monitoring Analytics, Answer to Exelon and PSEG, <http://www.monitoringanalytics.com/filings/2020/IMM_Answer_to_Exelon_PSEG_Docket_No_EO20030203_20200715.pdf> (July 15, 2020).

35 See Monitoring Analytics, LLC, "Potential Impacts of the Creation of a ComEd FRR," , <http://www.monitoringanalytics.com/reports/Reports/2019/IMM_Potential_Impacts_of_the_Creation_of_a_ComEd_FRR_20191218.pdf> (December 18, 2020).

36 See Monitoring Analytics, LLC, "Potential Impacts of the Creation of Maryland FRRs," <http://www.monitoringanalytics.com/reports/Reports/2020/IMM_Potential_Impacts_of_the_Creation_of_Maryland_FRRs_20200416.pdf> (April 16, 2020).

37 See Monitoring Analytics, LLC, "Potential Impacts of the Creation of New Jersey FRRs," <http://www.monitoringanalytics.com/reports/Reports/2020/IMM_Potential_Impacts_of_the_Creation_of_New_Jersey_FRRS_20200513.pdf> (May 13, 2020).

38 See Monitoring Analytics, LLC, "Potential Impacts of the Creation of Ohio FRRs," <http://www.monitoringanalytics.com/reports/Reports/2020/IMM_Potential_Impacts_of_the_Creation_of%20Ohio_FRRs_20200717.pdf> (July 17, 2020).

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The competitive offers of renewables, based on the net ACR of current technologies, are likely to clear in the capacity market. The competitive offers of nuclear plants, based on net ACR, are likely to clear in the capacity market.

Cost of service resources have the option of using the existing FRR rules, which would allow regulated utilities to opt out of the capacity market. The expected impact of the SMR design on the offers and clearing of regulated cost of service resources that remained in the capacity market would be from zero to insignificant. The competitive offers of these resources, based on net ACR, are likely to clear in the capacity market.

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

The definition of demand side resources in PJM capacity markets is flawed in a variety of ways. The current demand side definition should be replaced with a definition that includes demand on the demand side of the market. There are ways to ensure and enhance the vibrancy of demand side without negatively affecting markets for generation. There are other price formation issues in the capacity market that should also be examined and addressed.[39]

The Commission issued its MOPR order on December 19, 2019 ("December 19th Order").[40] The December 19th Order defines a clear path for defending competitive wholesale power markets in PJM. The Order defines a clear, consistent and comprehensive approach to the PJM markets and to the role of subsidized resources in the markets. The 2022/2023 BRA is expected to be run by mid 2021.[41]

In another proceeding, the Commission has ordered PJM on compliance to propose revisions to the PJM market rules to implement a forward looking EAS offset to include forward looking energy and ancillary services revenues rather than historical.[42] The MMU has recommended such an approach. The change in the offset will affect MOPR floor prices and the results of unit specific reviews under MOPR. PJM submitted its compliance filing on August 5, 2020, and the matter is now pending.

39 See Monitoring Analytics, LLC, "Analysis of the 2021/2022 RPM Base Residual Auction – Revised," <http://www.monitoringanalytics.com/reports/Reports/2018/IMM_Analysis_of_the_20212022_RPM_BRA_Revised_20180824.pdf> (August 24, 2008).

40 169 FERC ¶ 61,239.

41 Docket Nos. ER18-1314-000, -001, EL16-49-000, and EL18-178-000 (March 18, 2020 and June 1, 2020).

42 171 FERC ¶ 61,153 at PP 320–321 (2020).

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Table 5-2 RPM related MMU reports: 2019 through 2020

Date	Name
February 21, 2019	IMM Complaint re CONE x B Offers Docket No. EL19-47-000 http://www.monitoringanalytics.com/Filings/2019/IMM_Complaint_Docket_No_EL19-XXX_20190221.pdf
February 22, 2019	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2019/2020, 2020/2021 and 2021/2022 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/Messages/RPM_Must_Offer_Obligation_20190222.pdf
April 2, 2019	IMM Comments re ACR Review Waiver Docket No. ER19-1404 http://www.monitoringanalytics.com/Filings/2019/IMM_Comments_Docket_No_ER19-1404_20190402.pdf
April 10, 2019	IMM Answer and Motion for Leave to Answer re Cube Yadkin Complaint Docket No. EL19-51 http://www.monitoringanalytics.com/Filings/2019/IMM_Answer_Docket_No_EL19-51_20190410.pdf
April 11, 2019	IMM Answer re Brookfield Energy Complaint Docket No. EL19-34 http://www.monitoringanalytics.com/Filings/2019/IMM_Answer_Docket%20No.%20EL19-34_20190411.pdf
April 30, 2019	IMM Answer Re CONE x B Offers Docket No. EL19-47 http://www.monitoringanalytics.com/Filings/2019/IMM_Answer_Docket_No_EL19-47_20190430.pdf
May 24, 2019	IMM Answer to PJM re MSOC Docket No. EL19-47, EL19-63 http://www.monitoringanalytics.com/Filings/2019/IMM_Answer_to_PJM_EL19-47_-63_20190524.pdf
June 28, 2019	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2020/2021, 2021/2022 and 2022/2023 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/Messages/RPM_Must_Offer_Obligation_20190628.pdf
August 23, 2019	IMM Answer re Capacity Resources and Must Offer Exception Process Docket No. ER19-2417 http://www.monitoringanalytics.com/Filings/2019/IMM_Answer_Docket_No_ER19-2417_20190823.pdf
September 6, 2019	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2020/2021, 2021/2022 and 2022/2023 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/Messages/RPM_Must_Offer_Obligations_20190906.pdf
September 12, 2019	PJM Generation Capacity and Funding Sources 2007/2008 through 2021/2022 Delivery Years http://www.monitoringanalytics.com/reports/Reports/2019/IMM_PJM_Generation_Capacity_and_Funding_Sources_20072008_through_20212022_Delivery_Years_20190912.pdf
September 13, 2019	Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2019 http://www.monitoringanalytics.com/reports/Reports/2019/IMM_Analysis_of_Replacement_Capacity_for_RPM_Commitments_June_1_2007_to_June_1_2019_20190913.pdf
September 17, 2019	IMM Response to Grid Strategies Report http://www.monitoringanalytics.com/reports/Market_Messages/Messages/IMM_Response_to_Grid_Strategies_Report_201909217.pdf
December 13, 2019	IMM Comments re Performance Assessment Intervals Docket No. EL19-47-000 http://www.monitoringanalytics.com/Filings/2019/IMM_Comments_Docket_No_ER15-623_EL15-29_EL19-47_20191213.pdf
December 18, 2019	Potential Impacts of the Creation of a ComEd FRR http://www.monitoringanalytics.com/reports/Reports/2019/IMM_Potential_Impacts_of_the_Creation_of_a_ComEd_FRR_20191218.pdf
December 26, 2019	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2020/2021, 2021/2022 and 2022/2023 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/RPM_Must_Offer_Obligations_20191226.pdf
January 16, 2020	Net Revenues for PJM RPM Base Residual Auctions in 2020 http://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Net_Revenues_20232024_RPM_BRA_20200116.pdf
January 17, 2020	IMM Request for Clarification re MOPR Order Docket Nos. EL16-49 and EL18-178 http://www.monitoringanalytics.com/filings/2020/IMM_Request_for_Clarification_Docket_Nos_EL16-49_EL18-178_20200117.pdf
January 21, 2020	CONE and ACR Values - Preliminary http://www.monitoringanalytics.com/reports/Presentations/2020/IMM_MIC_Special_Special_Session_CONE_and_ACR_Values_20200128.pdf
February 5, 2020	IMM Answer to Requests for Rehearing's Docket No. EL14-69 and EL18-178 http://www.monitoringanalytics.com/filings/2020/IMM_Answer_To_RFRS_Docket_Nos_EL14-69_EL18-178_20200205.pdf
February 17, 2020	IMM MOPR Gross CONE Template http://www.monitoringanalytics.com/reports/Presentations/2020/IMM_MOPR_Gross_CONE_Template_20200217.xlsx
February 18, 2020	IMM Second Request for Clarification re MOPR Docket No. EL18-178, EL16-49 http://www.monitoringanalytics.com/filings/2020/IMM_Second_Request_for_Clarification_Docket_No_EL18-178_%20EL16-49_20200218.pdf
February 18, 2020	Unit Specific Nuclear ACR Information http://www.monitoringanalytics.com/reports/Presentations/2020/IMM_MIC_MOPR_Unit_Specific_Nuclear_ACR_Information_20200219.pdf
February 21, 2020	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2020/2021, 2021/2022 and 2022/2023 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_RPM_Must_Offer_Obligations_20200221.pdf
February 28, 2020	Monitoring Analytics ACR Template http://www.monitoringanalytics.com/reports/Presentations/2020/IMM_MIC_Special_Session_ACR_Template_20200228.pdf
March 20, 2020	Potential Impacts of the MOPR Order http://www.monitoringanalytics.com/reports/Reports/2020/IMM_Potential_Impacts_of_the_MOPR_Order_20200320.pdf
April 16, 2020	Potential Impacts of the Creation of Maryland FRRs http://www.monitoringanalytics.com/reports/Reports/2020/IMM_Potential_Impacts_of_the_Creation_of_Maryland_FRRs_20200416.pdf
May 6, 2020	Potential Compliance with P386 of FERC Order on Rehearing http://www.monitoringanalytics.com/reports/Presentations/2020/IMM_MIC_Special_Session_Potential_Compliance_with_P386_of_FERC_Order_on_Rehearing_20200506.pdf
May 13, 2020	Potential Impacts of the Creation of New Jersey FRRs http://www.monitoringanalytics.com/reports/Reports/2020/IMM_Potential_Impacts_of_the_Creation_of_New_Jersey_FRRS_20200513.pdf
May 15, 2020	IMM Request for Clarification re MOPR Ex Investigation Docket Nos. EL18-178-002 and EL16-49-002 http://www.monitoringanalytics.com/filings/2020/IMM_Request_for_Clarification_Docket_No_EL18-178-002_EL16-49-002_20200515.pdf
May 15, 2020	IMM Comments re MOPR-Ex Docket Nos. ER18-1314-00, EL16-49-000, EL18-178-000 http://www.monitoringanalytics.com/filings/2020/IMM_Comments_Docket_No_ER18-1314-003_EL16-49_EL18-178_20200515.pdf
May 20, 2020	IMM Comments re NJBPU Investigation of Resource Adequacy Alternatives Docket No. EO20030203 http://www.monitoringanalytics.com/filings/2020/IMM_Comments_Docket_No_EO20030203_20200520.pdf
June 22, 2020	IMM Comments re MOPR-Ex Compliance Filing Docket Nos. ER18-1314, EL16-49 and ERL8-178 http://www.monitoringanalytics.com/filings/2020/IMM_Comments_Docket_No_ER18-1314_EL16-49_ER18-178_20200622.pdf
June 24, 2020	IMM Reply Comments re NJ BPU Resource Adequacy Alternatives Docket No. EO20030203 http://www.monitoringanalytics.com/filings/2020/IMM_Reply_Comments_Docket_No_EO20030203_20200624.pdf
June 30, 2020	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2021/2022 and 2022/2023 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_RPM_Must_Offer_Obligations_20200630.pdf
July 15, 2020	IMM Answer to PSEG and Exelon Reply re New Jersey FRR Docket No. EO20030203 http://www.monitoringanalytics.com/filings/2020/IMM_Answer_to_Exelon_PSEG_Docket_No_EO20030203_20200715.pdf
July 17, 2020	Potential Impacts of the Creation of Ohio FRRs http://www.monitoringanalytics.com/reports/Reports/2020/IMM_Potential_Impacts_of_the_Creation_of%20Ohio_FRRs_20200717.pdf
July 20, 2020	IMM Comments re NJ BPU Nuclear Power Plant ZECs Docket No. EO18080899 http://www.monitoringanalytics.com/filings/2020/IMM_Comments_Docket_No_EO18080899_20200720.pdf
July 23, 2020	IMM Answer re MOPR Ex Docket No. EL16-49, ER18-1314 and EL18-178 http://www.monitoringanalytics.com/filings/2020/IMM_Answer_Docket_No_EL16-49_ER18-1314_EL18-178_20200724.pdf
July 27, 2020	IMM Comments re ORDC Compliance Filing Docket No. EL19-58-002 and ER19-1486 http://www.monitoringanalytics.com/filings/2020/IMM_Comments_EL19-58-002_ER19-1486-20200727.pdf
September 15, 2020	2020 PJM Generation Capacity and Funding Sources: 2007/2008 through 2021/2022 http://www.monitoringanalytics.com/reports/Reports/2020/IMM_2020_PJM_Generation_Capacity_and_Funding_Sources_20072008_through_20212022_DY_20200915.pdf

Installed Capacity

On January 1, 2020, RPM installed capacity was 184,722.8 MW (Table 5-3).[43] Over the next nine months, new generation, unit deactivations, facility reratings, plus import and export shifts resulted in RPM installed capacity of 183,934.1 MW on September 30, 2020, a decrease of 788.7 MW or 0.4 percent from the January 1 level.[44 45] The 788.7 MW decrease was the result of a decrease in imports (582.9 MW), an increase in exports (328.9 MW), derates (81.4 MW), and deactivations (2,456.1 MW), offset by new or reactivated generation (2,233.1 MW) and uprates (427.5 MW).

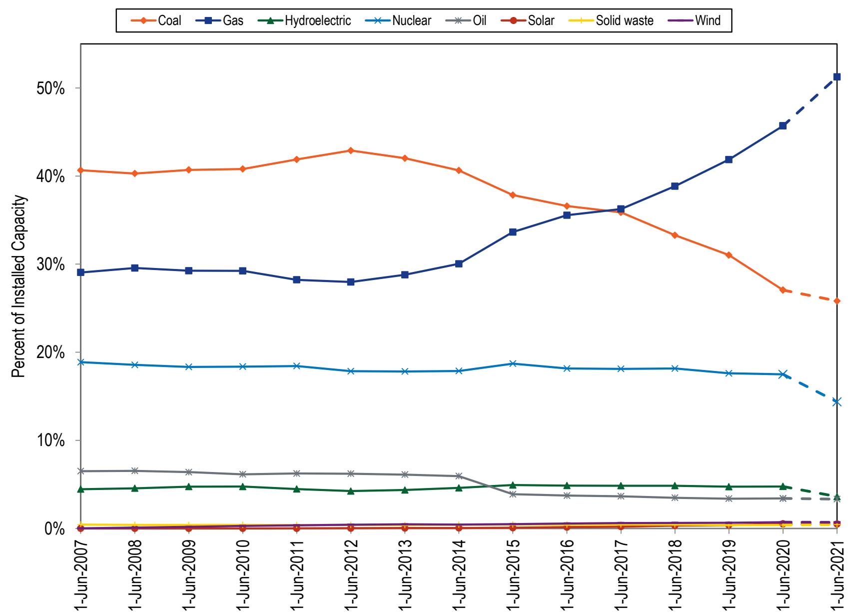
At the beginning of the new delivery year on June 1, 2020, RPM installed capacity was 184,583.3 MW, a decrease of 1,069.2 MW or 0.6 percent from the May 31, 2020, level of 185,652.5 MW.

Table 5-3 Installed capacity (By fuel source): January 1, May 31, June 1, and September 30, 2020

	01-Jan-20		31-May-20		01-Jun-20		30-Sep-20	
	MW	Percent	MW	Percent	MW	Percent	MW	Percent
Coal	52,181.3	28.2%	51,281.6	27.6%	49,942.4	27.1%	49,649.9	27.0%
Gas	82,313.9	44.6%	84,195.7	45.4%	84,355.1	45.7%	83,971.4	45.7%
Hydroelectric	8,873.9	4.8%	8,862.2	4.8%	8,778.7	4.8%	8,779.3	4.8%
Nuclear	32,297.9	17.5%	32,285.4	17.4%	32,285.4	17.5%	32,285.4	17.6%
Oil	6,311.0	3.4%	6,282.8	3.4%	6,282.8	3.4%	6,282.8	3.4%
Solar	791.0	0.4%	791.0	0.4%	946.9	0.5%	960.3	0.5%
Solid waste	695.6	0.4%	695.6	0.4%	695.6	0.4%	695.6	0.4%
Wind	1,258.2	0.7%	1,258.2	0.7%	1,296.4	0.7%	1,309.4	0.7%
Total	184,722.8	100.0%	185,652.5	100.0%	184,583.3	100.0%	183,934.1	100.0%

Figure 5-1 shows the share of installed capacity by fuel source for the first day of each delivery year, from June 1, 2007, to June 1, 2020, as well as the expected installed capacity for the 2021/2022 delivery year, based on the results of all auctions held through September 30, 2020.[46] On June 1, 2007, coal comprised 40.7 percent of the installed capacity, reached a maximum of 42.9 percent in 2012, decreased to 27.1 percent on June 1, 2020, and is projected to decrease to 25.8 percent by June 1, 2021. The share of gas increased from 29.1 percent on June 1, 2007, to 45.7 percent on June 1, 2020, and is projected to increase to 51.3 percent on June 1, 2021.

Figure 5-1 Percent of installed capacity (By fuel source): June 1, 2007 through June 1, 2021



43 Percent values shown in Table 5-3 are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

44 Unless otherwise specified, the capacity described in this section is the summer installed capacity rating of all PJM generation capacity resources, as entered into the Capacity Exchange system, regardless of whether the capacity cleared in the RPM auctions.

45 Wind resources accounted for 1,309.4 MW, and solar resources accounted for 960.3 MW of installed capacity in PJM on September 30, 2020. PJM administratively reduces the capabilities of all wind generators to 14.7 percent for wind farms in mountainous terrain and 17.6 percent for wind farms in open terrain, and solar generators to 42.0 percent for ground mounted fixed panel, 60.0 percent for ground mounted tracking panel, and 38.0 percent for other than ground mounted solar arrays, of nameplate capacity when determining the installed capacity because wind and solar resources cannot be assumed to be available on peak and cannot respond to dispatch requests. As data become available, unforced capability of wind and solar resources will be calculated using actual data. There are additional wind and solar resources not reflected in total capacity because they are energy only resources and do not participate in the PJM Capacity Market. See "PJM Manual 21: Rules and Procedures for Determination of Generating Capability," Appendix B.3 Calculation Procedure, Rev. 14 (Aug. 1, 2019).

46 Due to EFORd values not being finalized for future delivery years, the projected installed capacity is based on cleared unforced capacity (UCAP) MW using the EFORd submitted with the offer.

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Table 5-4 shows the RPM installed capacity on January 1, 2020, through September 30, 2020, for the top five generation capacity resource owners, excluding FRR committed MW.

Table 5-4 Installed capacity by parent company: January 1, May 31, June 1, and September 30, 2020

	01-Jan-20			31-May-20			01-Jun-20			30-Sep-20		
Parent Company	ICAP (MW)	Percent of Total ICAP	Rank	ICAP (MW)	Percent of Total ICAP	Rank	ICAP (MW)	Percent of Total ICAP	Rank	ICAP (MW)	Percent of Total ICAP	Rank
Exelon Corporation	21,165.8	12.4%	1	21,041.9	12.3%	1	20,801.8	12.1%	1	20,788.8	12.2%	1
Dominion Resources, Inc.	20,198.5	11.8%	2	20,198.5	11.8%	2	20,549.9	12.0%	2	20,525.1	12.0%	2
FirstEnergy Corp.	11,609.3	6.8%	3	4,102.5	2.4%	12	4,100.6	2.4%	12	4,100.6	2.4%	12
Vistra Energy Corp.	11,451.0	6.7%	4	11,290.9	6.6%	3	11,319.0	6.6%	3	11,319.0	6.6%	3
Talen Energy Corporation	10,964.6	6.4%	5	10,964.6	6.4%	4	10,839.4	6.3%	4	10,839.4	6.4%	4
LS Power Group	7,839.5	4.6%	7	8,709.5	5.1%	5	8,862.5	5.2%	5	8,841.8	5.2%	5

The sources of funding for generation owners can be categorized as one of two types: market and nonmarket. Market funding is from private investors bearing the investment risk without guarantees or support from any public sources, subsidies or guaranteed payment by ratepayers. Providers of market funding rely entirely on market revenues. Nonmarket funding is from guaranteed revenues, including cost of service rates for a regulated utility and subsidies. Table 5-5 shows the RPM installed capacity on January 1, 2020, to September 30, 2020, by funding type.

Table 5-5 Installed capacity by funding type: January 1, May 31, June 1, and September 30, 2020

	01-Jan-20		31-May-20		01-Jun-20		30-Sep-20	
Funding Type	ICAP (MW)	Percent of Total ICAP	ICAP (MW)	Percent of Total ICAP	ICAP (MW)	Percent of Total ICAP	ICAP (MW)	Percent of Total ICAP
Market	152,177.4	82.4%	153,111.1	82.5%	151,765.2	82.2%	151,140.8	82.2%
Nonmarket	32,545.4	17.6%	32,541.4	17.5%	32,818.1	17.8%	32,793.3	17.8%
Total	184,722.8	100.0%	185,652.5	100.0%	184,583.3	100.0%	183,934.1	100.0%

Fuel Diversity

Figure 5-2 shows the fuel diversity index (FDI_c) for RPM installed capacity.[47] The FDI_c is defined as $1-\sum_{i=1}^{N} s_i^2$, where s_i is the percent share of fuel type i. The minimum possible value for the FDI_c is zero, corresponding to all capacity from a single fuel type. The maximum possible value for the FDI_c is achieved when each fuel type has an equal share of capacity. For a capacity mix of eight fuel types, the maximum achievable index is 0.875. The fuel type categories used in the calculation of the FDI_c are the eight fuel sources in Table 5-3. The FDI_c is stable and does not exhibit any long-term trends. The only significant deviation occurred with the expansion of the PJM footprint. On April 1, 2002, PJM expanded with the addition of Allegheny Power System, which added about 12,000 MW of generation.[48] The reduction in the FDI_c resulted from an increase in coal capacity resources. A similar but more significant reduction occurred in 2004 with the expansion into the ComEd, AEP, and Dayton Power & Light Control Zones.[49] The average FDI_c for the first nine months of 2020 decreased 1.4 percent compared to the first nine months of 2019. Figure 5-2 also includes the expected FDI_c through June 2021 based on cleared RPM auctions. The expected FDI_c is indicated in Figure 5-2 by the dashed orange line.

The FDI_c was used to measure the impact of potential retirements of resources that the MMU has identified as being at risk of retirement. A total of 9,543.0 MW of coal, diesel, and nuclear capacity were identified as being at risk of retirement.[50] Generation owners that intend to retire a generator are required by the tariff to notify PJM at least 90 days in advance of the retirement.[51] There are 4,556.0 MW of generation that have a requested retirement date

47 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.
48 On April 1, 2002, the PJM Region expanded with the addition of Allegheny Power System under a set of agreements known as "PJM-West." See page 4 in the *2002 State of the Market Report for PJM* for additional details.
49 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.
50 See the *2019 State of the Market Report for PJM*, Volume 2, Section 7: Net Revenue, Units at Risk.
51 See OATT Part V § 113.1.

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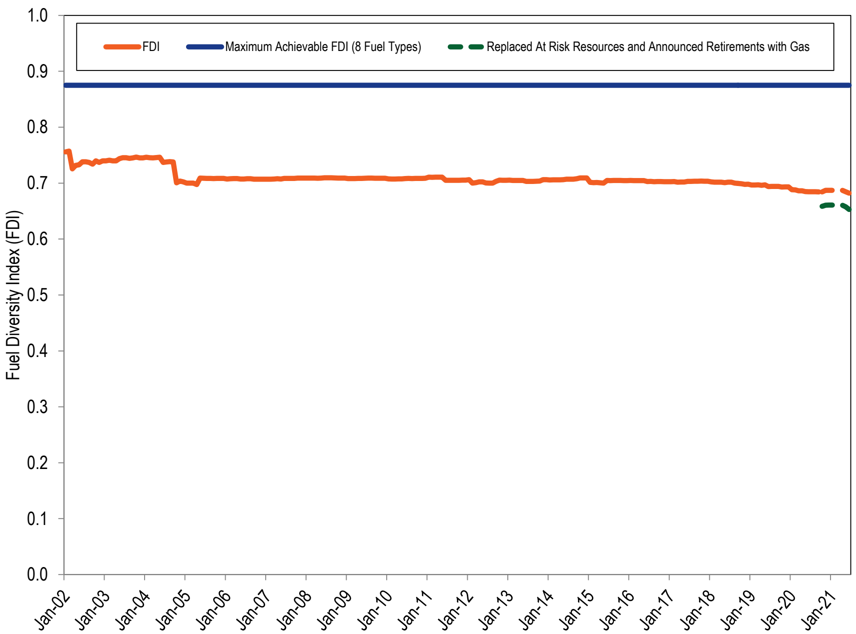
after September 30, 2020.[52] The dashed green line in Figure 5-2 shows the FDI_c calculated assuming that the capacity that cleared in an RPM auction from the at risk resources and other resources with deactivation notices is replaced by gas generation.[53] The FDI_c under these assumptions would decrease by 3.9 percent on average from the expected FDI_c for the period October 1, 2020, through June 1, 2021.

Figure 5-2 Fuel Diversity Index for installed capacity: January 1, 2002 through June 1, 2021



52 See *2020 Quarterly State of the Market Report for PJM: January through September*, Section 12: Generation and Transmission Planning, Table 12-9.

53 For this analysis resources for which PJM has received deactivation notifications were replaced with gas capacity beginning on the projected retirement date listed in the deactivation data. At risk resources that have not notified PJM regarding deactivation were replaced with gas capacity beginning on October 1, 2020.

RPM Capacity Market

The RPM Capacity Market, implemented June 1, 2007, is a forward-looking, annual, locational market, with a must offer requirement for Existing Generation Capacity Resources and mandatory participation by load, with performance incentives, that includes clear market power mitigation rules and that permits the direct participation of demand-side resources.

Annual base auctions are held in May for delivery years that are three years in the future. Effective January 31, 2010, First, Second, and Third Incremental Auctions are conducted 20, 10, and three months prior to the delivery year.[54] In the first nine months of 2020, the 2020/2021 RPM Third Incremental Auction and the 2021/2022 RPM Second Incremental Auction were conducted.[55]

Market Structure

Supply

Table 5-6 shows generation capacity changes since the implementation of the Reliability Pricing Model through the 2019/2020 Delivery Year. The 21,993.1 MW increase was the result of new generation capacity resources (33,614.4 MW), reactivated generation capacity resources (1,362.8 MW), uprates (7,002.2 MW), integration of external zones (21,967.5 MW), a net decrease in capacity exports (1,905.2 MW), offset by a net decrease in capacity imports (1,013.6 MW), deactivations (39,400.0 MW) and derates (3,445.4 MW).

Table 5-7 shows the calculated RPM reserve margin and reserve in excess of the defined installed reserve margin (IRM) for June 1, 2016, through June 1, 2021, and accounts for cleared capacity, replacement capacity, and deficiency MW for all auctions held and the most recent peak load forecast for each delivery year. The completion of the replacement process using cleared buy bids from RPM incremental auctions includes two transactions. The first step is for the entity to submit and clear a buy bid in an RPM incremental auction. The next step is for the entity to complete a separate replacement transaction

54 See Letter Order, Docket No. ER10-366-000 (January 22, 2010).

55 FERC granted PJM's request for waiver of its Open Access Transmission Tariff to delay the 2022/2023 RPM Base Residual Auction from May 2019 to August 2019. See 164 FERC ¶ 61,153 (2018). FERC subsequently denied PJM's motion seeking clarification of the June 29, 2018, Order (163 FERC ¶ 61,236) and directed PJM not to run the 2022/2023 BRA in August 2019. See 168 FERC ¶ 61,051 (2019).

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using the cleared buy bid capacity. Without an approved early replacement transaction requested for defined physical reasons, replacement capacity transactions can be completed only after the EFORds for the delivery year are finalized, on November 30 in the year prior to the delivery year, but before the start of the delivery day. The calculated reserve margins for June 1, 2021, does not account for cleared buy bids that have not been used in replacement capacity transactions. The projected reserve margin for June 1, 2021, accounts for projected replacement capacity using cleared buy bids by applying the rate at which historical buy bids have been used.

Future Changes in Generation Capacity[56]

As shown in Table 5-6, for the period from the introduction of the RPM capacity market design in the 2007/2008 Delivery Year through the 2019/2020 Delivery Year, internal installed capacity decreased by 866.0 MW after accounting for new capacity resources, reactivations, and uprates (41,979.4 MW) and capacity deactivations and derates (42,845.4 MW).

For the current and future delivery years (2020/2021 through 2021/2022), new generation capacity is defined as capacity that cleared an RPM auction for the first time in the specified delivery year. Based on expected completion rates of cleared new generation capacity (2,640.4MW) and pending deactivations (3,464.7MW), PJM capacity is expected to decrease by 824.3 MW for the 2020/2021 through 2021/2022 Delivery Years.

Table 5-6 Generation capacity changes: 2007/2008 through 2019/2020[57] [58]

	ICAP (MW)								
	New	Reactivations	Uprates	Integration	Net Change in Capacity Imports	Net Change in Capacity Exports	Deactivations	Derates	Net Change
2007/2008	45.0	0.0	691.5	0.0	70.0	15.3	380.0	417.0	(5.8)
2008/2009	815.4	238.3	987.0	0.0	473.0	(9.9)	609.5	421.0	1,493.1
2009/2010	406.5	0.0	789.0	0.0	229.0	(1,402.2)	108.4	464.3	2,254.0
2010/2011	153.4	13.0	339.6	0.0	137.0	367.7	840.6	223.5	(788.8)
2011/2012	3,096.4	354.5	507.9	16,889.5	(1,183.3)	(1,690.3)	2,542.0	176.2	18,637.1
2012/2013	1,784.6	34.0	528.1	47.0	342.4	84.0	5,536.0	317.8	(3,201.7)
2013/2014	198.4	58.0	372.8	2,746.0	934.3	28.9	2,786.9	288.3	1,205.4
2014/2015	2,276.8	20.7	530.2	0.0	2,335.7	177.3	4,915.6	360.3	(289.8)
2015/2016	4,291.8	90.0	449.0	0.0	511.4	(117.8)	8,338.2	215.8	(3,094.0)
2016/2017	3,679.3	532.0	419.2	0.0	575.6	722.9	659.4	206.7	3,617.1
2017/2018	4,127.3	5.0	562.1	0.0	(1,025.1)	(695.1)	2,657.4	148.5	1,558.5
2018/2019	8,127.5	4.0	330.9	2,120.0	(3,217.0)	212.7	6,730.0	89.2	333.5
2019/2020	4,612.0	13.3	494.9	165.0	(1,196.6)	401.3	3,296.0	116.8	274.5
Total	33,614.4	1,362.8	7,002.2	21,967.5	(1,013.6)	(1,905.2)	39,400.0	3,445.4	21,993.1

56 For more details on future changes in generation capacity, see "2020 PJM Generation Capacity and Funding Sources 2007/2008 through 2021/2022 Delivery Years," <http://www.monitoringanalytics.com/reports/Reports/2020/IMM_2020_PJM_Generation_Capacity_and_Funding_Sources_20072008_through_20212022_DY_20200915.pdf> (September 15, 2020).
57 The capacity changes in this report are calculated based on June 1 through May 31.
58 The calculated export MW for 2012/2013 were revised from the *2020 Quarterly State of the Market Report for PJM: January through March*.

Table 5-7 RPM reserve margin: June 1, 2016, to June 1, 2021[59 60]

	Generation and DR RPM Committed Less Deficiency UCAP (MW)	Forecast Peak Load	FRR Peak Load	PRD	RPM Peak Load	IRM	Pool Wide Average EFORd	Generation and DR RPM Committed Less Deficiency ICAP (MW)	Reserve Margin	Reserve Margin in Excess of IRM		Projected Replacement Capacity using Cleared Buy Bids UCAP (MW)	Projected Reserve Margin
										Percent	ICAP (MW)		
01-Jun-16	160,883.3	152,356.6	12,511.6	0.0	139,845.0	16.4%	5.91%	170,988.7	22.3%	5.9%	8,209.2	0.0	22.3%
01-Jun-17	163,872.0	153,230.1	12,837.5	0.0	140,392.6	16.6%	5.94%	174,220.7	24.1%	7.5%	10,522.9	0.0	24.1%
01-Jun-18	161,242.6	152,407.9	12,732.9	0.0	139,675.0	16.1%	6.07%	171,662.5	22.9%	6.8%	9,499.8	0.0	22.9%
01-Jun-19	162,276.1	151,643.5	12,284.2	0.0	139,359.3	16.0%	6.08%	172,781.2	24.0%	8.0%	11,124.4	0.0	24.0%
01-Jun-20	159,560.4	148,355.3	11,488.3	558.0	136,309.0	15.5%	5.78%	169,348.8	24.2%	8.7%	11,911.9	0.0	24.2%
01-Jun-21	164,773.5	147,501.6	11,394.3	510.0	135,597.3	15.1%	5.56%	174,474.3	28.7%	13.6%	18,401.8	7,325.0	23.0%

Sources of Funding[61]

Developers use a variety of sources to fund their projects, including Power Purchase Agreements (PPA), cost of service rates, and private funds (from internal sources or private lenders and investors). PPAs can be used for a variety of purposes and the use of a PPA does not imply a specific source of funding.

New and reactivated generation capacity from the 2007/2008 Delivery Year through the 2019/2020 Delivery Year totaled 34,977.2 MW (83.3 percent of all additions), with 26,796.1 MW from market funding and 8,181.1 MW from nonmarket funding. Uprates to existing generation capacity from the 2007/2008 Delivery Year through the 2019/2020 Delivery Year totaled 7,002.2 MW (16.7 percent of all additions), with 5,537.8 MW from market funding and 1,464.4 MW from nonmarket funding. In summary, of the 41,979.4 MW of additional capacity from new, reactivated, and uprated generation that cleared in RPM auctions for the 2007/2008 through 2019/2020 Delivery Years, 32,333.9 MW (77.0 percent) were based on market funding.

Of the 2,640.4 MW of the additional generation capacity (new resources, reactivated resources, and uprates) that cleared in RPM auctions for the 2020/2021 through 2021/2022 Delivery Years, 2,214.9 MW are not yet in service. Of those 2,214.9 MW that have not yet gone into service, 2,195.9 MW have market funding and 19.0 MW have nonmarket funding. Applying the historical completion rates, 73.1 percent of all the projects in development are expected to go into service (1,604.1 MW of the 2,195.9 MW of market funded projects; 13.9 MW of the 19.0 MW of nonmarket funded projects). Together, 1,618.0 MW of the 2,214.9 MW of new generation capacity that cleared MW in RPM and are not yet in service are expected to go into service through the 2021/2022 Delivery Year.

Of the 425.5 MW of the additional generation capacity that cleared in RPM auctions for the 2020/2021 through 2021/2022 Delivery Years and are already in service, 357.7 MW (84.1 percent) are based on market funding and 67.8 MW (15.9 percent) are based on nonmarket funding. In summary, 2,553.6 MW (96.7 percent) of the additional generation capacity (425.5 MW in service and 2,214.9 MW not yet in service) that cleared in RPM auctions for the 2020/2021 through 2021/2022 Delivery Years are based on market funding. Capacity additions based on nonmarket funding are 86.8 MW (3.3 percent) of proposed generation that cleared at least one RPM auction for the 2020/2021 through 2021/2022 Delivery Years.

59 The calculated reserve margins in this table do not include EE on the supply side or the EE add back on the demand side. The EE excluded from the supply side for this calculation includes annual EE and summer EE. This is how PJM calculates the reserve margin.
60 These reserve margin calculations do not consider Fixed Resource Requirement (FRR) load.
61 For more details on sources of funding for generation capacity, see "2020 PJM Generation Capacity and Funding Sources 2007/2008 through 2021/2022 Delivery Years," <http://www.monitoringanalytics.com/reports/Reports/2020/IMM_2020_PJM_Generation_Capacity_and_Funding_Sources_20072008_through_20212022_DY_20200915.pdf> (September 15, 2020).

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Demand

The MMU analyzed market sectors in the PJM Capacity Market to determine how they met their load obligations. The PJM Capacity Market was divided into the following sectors:

- **PJM EDC.** EDCs with a franchise service territory within the PJM footprint. This sector includes traditional utilities, electric cooperatives, municipalities and power agencies.
- **PJM EDC Generating Affiliate.** Affiliate companies of PJM EDCs that own generating resources.
- **PJM EDC Marketing Affiliate.** Affiliate companies of PJM EDCs that sell power and have load obligations in PJM, but do not own generating resources.
- **Non-PJM EDC.** EDCs with franchise service territories outside the PJM footprint.
- **Non-PJM EDC Generating Affiliate.** Affiliate companies of non-PJM EDCs that own generating resources.
- **Non-PJM EDC Marketing Affiliate.** Affiliate companies of non-PJM EDCs that sell power and have load obligations in PJM, but do not own generating resources.
- **Non-EDC Generating Affiliate.** Affiliate companies of non-EDCs that own generating resources.
- **Non-EDC Marketing Affiliate.** Affiliate companies of non-EDCs that sell power and have load obligations in PJM, but do not own generating resources.

On June 1, 2020, PJM EDCs and their affiliates maintained a large market share of load obligations under RPM, together totaling 59.7 percent (Table 5-8), down from 60.1 percent on June 1, 2019. The combined market share of LSEs not affiliated with any EDC and of non-PJM EDC affiliates was 40.3 percent, up from 39.9 percent on June 1, 2019. The share of capacity market load obligation fulfilled by PJM EDCs and their affiliates, and LSEs not affiliated with any EDC and non-PJM EDC affiliates from June 1, 2007, to June 1, 2020, is shown in Figure 5-3. PJM EDCs' and their affiliates' share of load obligation has decreased from 77.5 percent on June 1, 2007, to 59.7 percent on June 1, 2020. The share of load obligation held by LSEs not affiliated with any EDC and non-PJM EDC affiliates increased from 22.5 percent on June 1, 2007, to 40.3 percent on June 1, 2020. Prior to the 2012/2013 Delivery Year, obligation was defined as cleared and make whole MW in the Base Residual Auction and the Second Incremental Auction plus ILR forecast obligations. Effective with the 2012/2013 Delivery Year, obligation is defined as the sum of the unforced capacity obligations satisfied through all RPM auctions for the delivery year.

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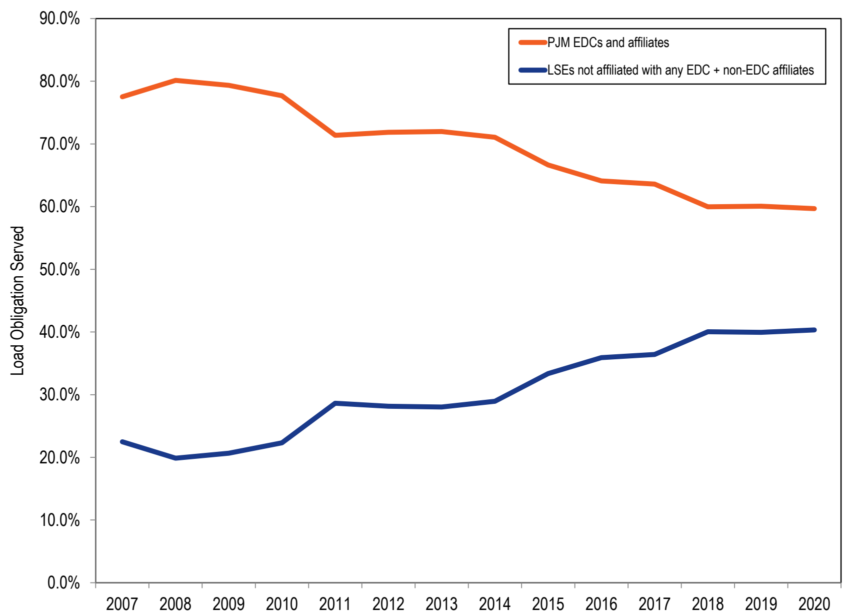
Table 5-8 Capacity market load obligation served: June 1, 2019 and June 1, 2020

	1-Jun-19		1-Jun-20		Change	
	Obligation (MW)	Percent of total obligation	Obligation (MW)	Percent of total obligation	Obligation (MW)	Percent of total obligation
PJM EDCs and Affiliates	113,416.3	60.1%	104,849.4	59.7%	(8,566.8)	(0.4%)
LSEs not affiliated with any EDC + non EDC Affiliates	75,445.0	39.9%	70,838.3	40.3%	(4,606.7)	0.4%
Total	188,861.3	100.0%	175,687.7	100.0%	(13,173.6)	0.0%

Figure 5-3 Capacity market load obligation served: June 1, 2007 through June 1, 2020



Capacity Transfer Rights (CTRs)

Capacity Transfer Rights (CTRs) are used to return capacity market congestion revenues to load. Load pays for the transmission system through firm transmission charges and pays congestion. Capacity market congestion revenues are the difference between the total dollars paid by load for capacity and the total dollars received by capacity market sellers. CTRs permit customers to receive the benefit of importing cheaper capacity using transmission capability. The MW of CTRs available for allocation to LSEs in an LDA are equal to the Unforced Capacity imported into the LDA, based on the results of the Base Residual Auction and Incremental Auctions, less any MW of CETL paid for directly by market participants in the form of Qualifying Transmission Upgrades (QTUs) cleared in an RPM Auction, and Incremental Capacity Transfer Rights (ICTRs). There are two types of ICTRs, those allocated to a New Service Customer obligated to fund a transmission facility or upgrade and those associated with Incremental Rights Eligible Required Transmission Enhancements.

For LDAs in which the RPM auctions for a delivery year resulted in a positive average weighted Locational Price Adder, an LSE with CTRs corresponding to the LDA is entitled to a payment or charge equal to the Locational Price Adder multiplied by the MW of the LSEs' CTRs.

In the 2021/2022 RPM Base Residual Auction, EMAAC had 4,352.6 MW of CTRs with a total value of $40,877,295, PSEG had 4,990.5 MW of CTRs with a total value of $70,238,159, ATSI had 6,402.8 MW of CTRs with a total value of $73,219,252, ComEd had 1,527.9 MW of CTRs with a total value of $30,978,820, and BGE had 5,125.6 MW of CTRs with a total value of $112,812,971.

EMAAC had 40.0 MW of customer funded ICTRs with a total value of $375,658, PSEG had 41.0 MW of customer funded ICTRs with a total value of $577,050, BGE had 65.7 MW of customer funded ICTRs with a total value of $1,446,024,

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and ComEd had 1,097.0 MW of customer funded ICTRs with a total value of $22,242,498.

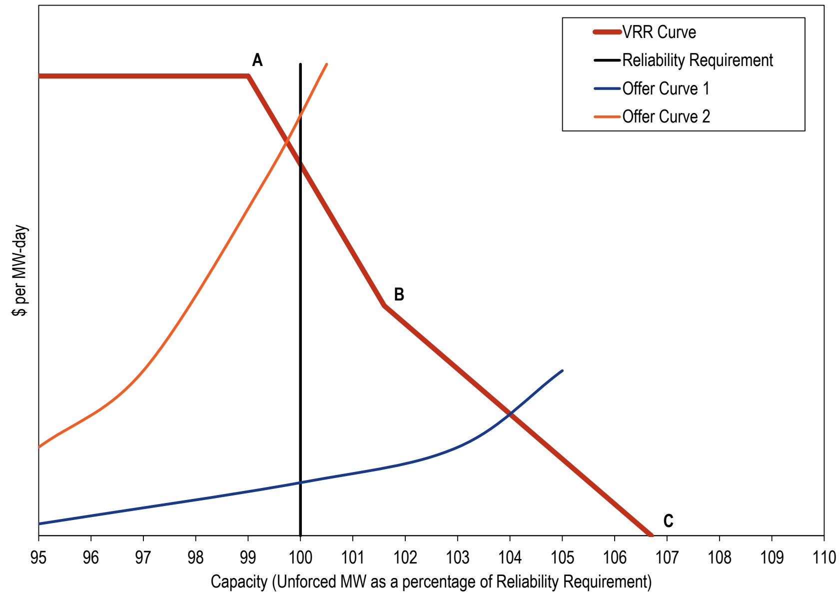
EMAAC had 948.0 MW of ICTRs due to Incremental Rights-Eligible Required Transmission Enhancements with a value of $8,903,095. PSEG had 499.4 MW of ICTRs due to Incremental Rights-Eligible Required Transmission Enhancements with a value of $7,028,755. BGE had 306.0 MW of ICTRs due to Incremental Rights-Eligible Required Transmission Enhancements with a value of $6,734,907.

Demand Curve

Effective for the 2018/2019 and subsequent Delivery Years, PJM revised the variable resource requirement (VRR) curve. The starting MW point of the downward sloping demand curve is set at 99.0 percent of the reliability requirement. The highest MW point is set at 106.7 percent of the reliability requirement. Almost all of the downward sloping part of the VRR curve lies to the right side of the reliability requirement.

The PJM definition of the VRR curve means the clearing price and cleared quantity will be higher, almost without exception, using the current VRR curve than using a vertical demand curve at the reliability requirement. As a result, payments for capacity will be higher. Figure 5-4 shows the RTO VRR curve and RTO reliability requirement for the 2022/2023 RPM BRA. The clearing price and cleared quantity would be lower if a vertical VRR curve set at the reliability requirement were used in place of the existing VRR curve. This is the case if the supply curve intersects the VRR curve to the right side of the reliability requirement (Offer Curve 1). The only exception would be if the supply curve intersects the VRR curve to the left of the reliability requirement (Offer Curve 2). In that case, the clearing price and cleared quantity would be higher with the vertical demand curve than with the existing VRR curve. In almost all RPM auctions, the offer curve intersected the VRR curve to the right side of the vertical demand curve.

Figure 5-4 VRR curve relative to the reliability requirement: 2022/2023 Delivery Year



Market Concentration

Auction Market Structure

As shown in Table 5-9, in the 2021/2022 RPM Second Incremental Auction two participants in the EMAAC LDA market passed the three pivotal supplier (TPS) test.[62] Offer caps were applied to all sell offers for resources which were subject to mitigation when the capacity market seller did not pass the test, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, increased the market clearing price.[63 64 65]

62 The market definition used for the TPS test includes all offers with costs less than or equal to 1.50 times the clearing price. See *MMU Technical Reference for PJM Markets*, at "Three Pivotal Supplier Test" for additional discussion.
63 See OATT Attachment DD § 6.5.
64 Prior to November 1, 2009, existing DR and EE resources were subject to market power mitigation in RPM Auctions. See 129 FERC ¶ 61,081 at P 30 (2009).
65 Effective January 31, 2011, the RPM rules related to market power mitigation were changed, including revising the definition for planned generation capacity resource and creating a new definition for existing generation capacity resource for purposes of the must offer requirement and market power mitigation, and treating a proposed increase in the capability of a generation capacity resource the same in terms of mitigation as a planned generation capacity resource. See 134 FERC ¶ 61,065 (2011).

In applying the market structure test, the relevant supply for the RTO market includes all supply offered at less than or equal to 150 percent of the RTO cost-based clearing price. The relevant supply for the constrained LDA markets includes the incremental supply inside the constrained LDAs which was offered at a price higher than the unconstrained clearing price for the parent LDA market and less than or equal to 150 percent of the cost-based clearing price for the constrained LDA. The relevant demand consists of the MW needed inside the LDA to relieve the constraint.

Table 5-9 presents the results of the TPS test. A generation owner or owners are pivotal if the capacity of the owners' generation facilities is needed to meet the demand for capacity. The results of the TPS are measured by the residual supply index (RSI_x). The RSI_x is a general measure that can be used with any number of pivotal suppliers. The subscript denotes the number of pivotal suppliers included in the test. If the RSI_x is less than or equal to 1.0, the supply owned by the specific generation owner, or owners, is needed to meet market demand and the generation owners are pivotal suppliers with a significant ability to influence market prices. If the RSI_x is greater than 1.0, the supply of the specific generation owner or owners is not needed to meet market demand and those generation owners have a reduced ability to unilaterally influence market price.

Table 5-9 RSI results: 2019/2020 through 2021/2022 RPM Auctions[66]

RPM Markets	$RSI_{1, 1.05}$	RSI_3	Total Participants	Failed RSI_3 Participants
2019/2020 Base Residual Auction				
RTO	0.81	0.66	131	131
EMAAC	0.79	0.23	6	6
ComEd	0.74	0.12	6	6
BGE	0.00	0.00	1	1
2019/2020 First Incremental Auction				
RTO	0.63	0.50	53	53
EMAAC	0.00	0.00	5	5
2019/2020 Second Incremental Auction				
RTO	0.61	0.48	38	38
BGE	0.00	0.00	1	1

66 The RSI shown is the lowest RSI in the market.

Table 5-9 RSI results: 2019/2020 through 2021/2022 RPM Auctions (cont'd)

RPM Markets	$RSI_{1, 1.05}$	RSI_3	Total Participants	Failed RSI_3 Participants
2019/2020 Third Incremental Auction				
RTO	0.70	0.59	72	72
2020/2021 Base Residual Auction				
RTO	0.81	0.69	119	119
MAAC	0.67	0.77	24	24
EMAAC	0.45	0.18	21	21
ComEd	0.47	0.20	14	14
DEOK	0.00	0.00	1	1
2020/2021 First Incremental Auction				
RTO	0.47	0.42	47	47
2020/2021 Second Incremental Auction				
RTO	0.40	0.56	34	34
2020/2021 Third Incremental Auction				
RTO	0.54	0.72	59	59
MAAC	0.25	0.18	14	14
2021/2022 Base Residual Auction				
RTO	0.80	0.68	122	122
EMAAC	0.71	0.22	14	14
PSEG	0.20	0.01	5	5
ATSI	0.01	0.00	2	2
ComEd	0.08	0.02	5	5
BGE	0.23	0.00	3	3
2021/2022 First Incremental Auction				
RTO	0.57	0.48	26	26
EMAAC	0.00	0.82	5	3
PSEG	0.00	0.00	1	1
PSEG North	0.00	0.00	2	2
BGE	0.00	0.00	1	1
2021/2022 Second Incremental Auction				
RTO	0.19	0.12	19	19
EMAAC	0.05	0.23	7	5
PSEG	0.00	0.00	2	2
BGE	0.00	0.00	0	0

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Locational Deliverability Areas (LDAs)

Under the PJM Tariff, PJM determines, in advance of each BRA, whether defined Locational Deliverability Areas (LDAs) will be modeled in the auction. Effective with the 2012/2013 delivery year, an LDA is modeled as a potentially constrained LDA for a delivery year if the Capacity Emergency Transfer Limit (CETL) is less than 1.15 times the Capacity Emergency Transfer Objective (CETO), such LDA had a locational price adder in one or more of the three immediately preceding BRAs, or such LDA is determined by PJM in a preliminary analysis to be likely to have a locational price adder based on historic offer price levels. The rules also provide that starting with the 2012/2013 Delivery Year, EMAAC, SWMAAC, and MAAC LDAs are modeled as potentially constrained LDAs regardless of the results of the above three tests.[67] In addition, PJM may establish a constrained LDA even if it does not qualify under the above tests if PJM finds that "such is required to achieve an acceptable level of reliability."[68] A reliability requirement and a Variable Resource Requirement (VRR) curve are established for each modeled LDA. Effective for the 2014/2015 through 2016/2017 Delivery Years, a Minimum Annual and a Minimum Extended Summer Resource Requirement are established for each modeled LDA. Effective for the 2017/2018 Delivery Year, Sub-Annual and Limited Resource Constraints, replacing the Minimum Annual and a Minimum Extended Summer Resource Requirements, are established for each modeled LDA.[69] Effective for the 2018/2019 through the 2019/2020 Delivery Years, Base Capacity Demand Resource Constraint and a Base Capacity Resource Constraint, replacing the Sub-Annual and Limited Resource Constraints, are established for each modeled LDA.

Locational Deliverability Areas are shown in Figure 5-5, Figure 5-6 and Figure 5-7.

Figure 5-5 Map of locational deliverability areas

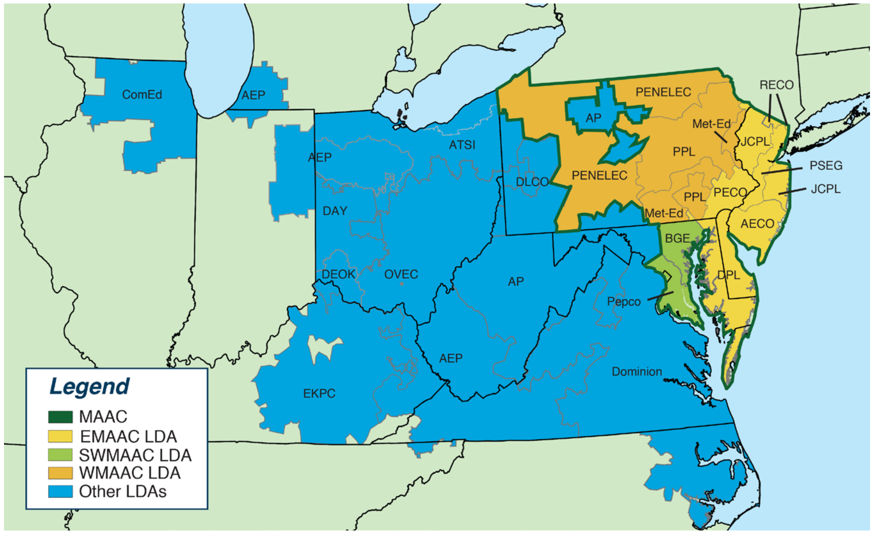
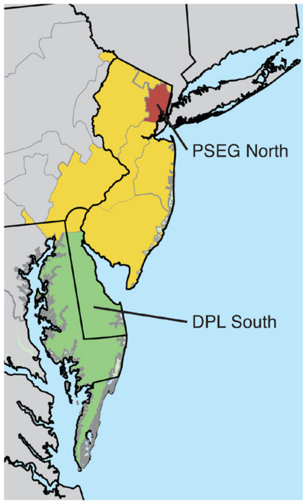


Figure 5-6 Map of RPM EMAAC subzonal LDAs



67 Prior to the 2012/2013 Delivery Year, an LDA with a CETL less than 1.05 times CETO was modeled as a constrained LDA in RPM. No additional criteria were used in determining modeled LDAs.
68 OATT Attachment DD § 5.10 (a) (ii).
69 146 FERC ¶ 61,052 (2014).

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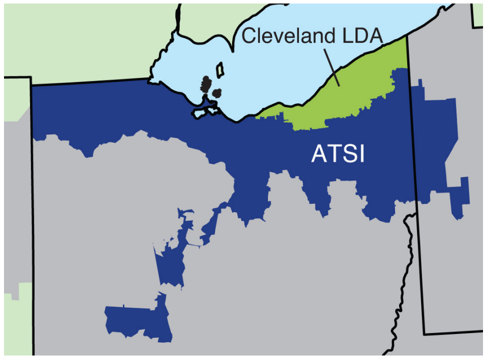
Figure 5-7 Map of RPM ATSI subzonal LDA



Imports and Exports

Units external to the metered boundaries of PJM can qualify as PJM capacity resources if they meet the requirements to be capacity resources. Generators on the PJM system that do not have a commitment to serve PJM loads in the given delivery year as a result of RPM auctions, FRR capacity plans, locational UCAP transactions, and/or are not designated as a replacement resource, are eligible to export their capacity from PJM.[70]

The PJM market rules should not create inappropriate barriers to either the import or export of capacity. The market rules in other balancing authorities should also not create inappropriate barriers to the import or export of capacity. The PJM market rules should ensure that the definition of capacity is enforced including physical deliverability, recallability and the obligation to make competitive offers into the PJM Day-Ahead Energy Market equal to ICAP MW. Physical deliverability can only be assured by requiring that all imports are deliverable to PJM load to ensure that they are full substitutes for internal capacity resources. Selling capacity into the PJM Capacity Market but making energy offers daily of $999 per MWh would not fulfill the requirements of a capacity resource to make a competitive offer, but would constitute economic withholding. This is one of the reasons that the rules governing the obligation to make a competitive offer in the day-ahead energy market should be clarified for both internal and external resources.

For the 2017/2018 through the 2019/2020 Delivery Years, Capacity Import Limits (CILs) are established for each of the five external source zones and the overall PJM region to account for the risk that external generation resources may not be able to deliver energy during the relevant delivery year due to the curtailment of firm transmission by third parties.[71] Capacity market sellers may request an exception to the CIL for an external generation resource by committing that the resource will be pseudo tied prior to the start of the relevant delivery year, by demonstrating that it has long-term firm transmission service confirmed on the complete transmission path from the resource to PJM, and by agreeing to be subject to the same RPM must offer requirement as internal PJM generation resources.

Effective June 9, 2015, an external generation capacity resource must obtain an exception to the CILs to be eligible to offer as a Capacity Performance Resource, which means that effective with the 2020/2021 Delivery Year, CILs are no longer defined as an RPM parameter.[72]

Effective May 9, 2017, enhanced pseudo tie requirements for external generation capacity resources were implemented, including a transition period with deliverability requirements for existing pseudo tie resources that have previously cleared an RPM auction.[73] The rule changes include: defining coordination with other Balancing Authorities when conducting pseudo tie studies; establishing an electrical distance requirement; establishing a market to market flowgate test to establish limits on the number of coordinated flowgates PJM must add in order to accommodate a new pseudo tie; a model consistency requirement; the requirement for the capacity market seller to provide written acknowledgement from the external Balancing Authority Areas that such pseudo tie does not require tagging and that firm allocations associated with any coordinated flowgates applicable to the external Generation Capacity Resource under any agreed congestion management process then in

70 OATT Attachment DD § 5.6.6(b).

71 147 FERC ¶ 61,060 (2014).

72 151 FERC ¶ 61,208 (2015).

73 161 FERC ¶ 61,197 (2017), *order denying reh'g*, 170 FERC ¶ 61,217 (2020).

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effect between PJM and such Balancing Authority Area will be allocated to PJM; the requirement for the capacity market seller to obtain long-term firm point to point transmission service for transmission outside PJM with rollover rights and to obtain network external designated transmission service for transmission within PJM; establishing an operationally deliverable standard; and modifying the nonperformance penalty definition for external generation capacity resources to assess performance at subregional transmission organization granularity.

As shown in Table 5-10, of the 4,470.4 MW of imports offered in the 2021/2022 RPM Base Residual Auction, 4,051.8 MW cleared. Of the cleared imports, 1,909.9 MW (47.1 percent) were from MISO.

Table 5-10 RPM imports: 2007/2008 through 2021/2022 RPM Base Residual Auctions

	UCAP (MW)					
	MISO		Non-MISO		Total Imports	
Base Residual Auction	Offered	Cleared	Offered	Cleared	Offered	Cleared
2007/2008	1,073.0	1,072.9	547.9	547.9	1,620.9	1,620.8
2008/2009	1,149.4	1,109.0	517.6	516.8	1,667.0	1,625.8
2009/2010	1,189.2	1,151.0	518.8	518.1	1,708.0	1,669.1
2010/2011	1,194.2	1,186.6	539.8	539.5	1,734.0	1,726.1
2011/2012	1,862.7	1,198.6	3,560.0	3,557.5	5,422.7	4,756.1
2012/2013	1,415.9	1,298.8	1,036.7	1,036.7	2,452.6	2,335.5
2013/2014	1,895.1	1,895.1	1,358.9	1,358.9	3,254.0	3,254.0
2014/2015	1,067.7	1,067.7	1,948.8	1,948.8	3,016.5	3,016.5
2015/2016	1,538.7	1,538.7	2,396.6	2,396.6	3,935.3	3,935.3
2016/2017	4,723.1	4,723.1	2,770.6	2,759.6	7,493.7	7,482.7
2017/2018	2,624.3	2,624.3	2,320.4	1,901.2	4,944.7	4,525.5
2018/2019	2,879.1	2,509.1	2,256.7	2,178.8	5,135.8	4,687.9
2019/2020	2,067.3	1,828.6	2,276.1	2,047.3	4,343.4	3,875.9
2020/2021	2,511.8	1,671.2	2,450.0	2,326.0	4,961.8	3,997.2
2021/2022	2,308.4	1,909.9	2,162.0	2,141.9	4,470.4	4,051.8

Demand Resources

There are two basic demand products incorporated in the RPM market design:[74]

- **Demand Resources (DR).** Interruptible load resource that is offered into an RPM Auction as capacity and receives the relevant LDA or RTO resource clearing price.
- **Energy Efficiency (EE) Resources.** Load resources that are offered into an RPM auction as capacity and receive the relevant LDA or RTO resource clearing price. The EE resource type was eligible to be offered in RPM auctions starting with the 2012/2013 Delivery Year and in incremental auctions in the 2011/2012 Delivery Year.[75]

Effective for the 2018/2019 and the 2019/2020 Delivery Years, there are two types of demand resource and energy efficiency resource products included in the RPM market design:[76 77]

- **Base Capacity Resources**
  - **Base Capacity Demand Resources.** A demand resource that is required to be available on any day from June through September for an unlimited number of interruptions. Base capacity DR is required to be capable of maintaining each interruption for at least 10 hours only during the hours of 10:00 a.m. to 10:00 p.m. EPT.
  - **Base Capacity Energy Efficiency Resources.** A project designed to achieve a continuous (during summer peak periods) reduction in electric energy consumption that is not reflected in the peak load forecast for the delivery year for which the base capacity energy efficiency resource is proposed, and that is fully implemented at all times during the relevant delivery year, without any requirement of notice, dispatch, or operator intervention. The peak period definition for the base capacity energy efficiency resource type includes the period from the hour ending 15:00 EPT and the hour ending 18:00 EPT from June through August, excluding weekends and federal holidays.

74 Effective June 1, 2007, the PJM active load management (ALM) program was replaced by the PJM load management (LM) program. Under ALM, providers had received a MW credit which offset their capacity obligation. With the introduction of LM, qualifying load management resources can be offered into RPM auctions as capacity resources and receive the clearing price.
75 Letter Order, Docket No. ER10-366-000 (January 22, 2010).
76 151 FERC ¶ 61,208.
77 PJM Reliability Assurance Agreement Article 1.

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- **Capacity Performance Resources**
  - **Annual Demand Resources.** A demand resource that is required to be available on any day in the relevant delivery year for an unlimited number of interruptions. Annual DR is required to be capable of maintaining each interruption for only 10 hours during the hours of 10:00 a.m. to 10:00 p.m. EPT for the period May through October and 6:00 a.m. to 9:00 p.m. EPT for the period November through April unless there is an Office of the Interconnection approved maintenance outage during October through April.
  - **Annual Energy Efficiency Resources.** A project designed to achieve a continuous (during summer and winter peak periods) reduction in electric energy consumption during peak periods that is not reflected in the peak load forecast for the delivery year for which the energy efficiency resource is proposed, and that is fully implemented at all times during the relevant delivery year, without any requirement of notice, dispatch, or operator intervention. The peak period definition for the annual energy efficiency resource type includes the period from the hour ending 15:00 EPT and the hour ending 18:00 EPT from June through August, and the period from the hour ending 8:00 EPT and the hour ending 9:00 EPT and the period from the hour ending 19:00 EPT and the hour ending 20:00 EPT from January through February, excluding weekends and federal holidays.

Effective with the 2020/2021 Delivery Year, the Capacity Performance Product will be the only capacity product type, with two possible season types, annual and summer.

- **Annual Capacity Performance Resources**
  - Annual Demand Resources
  - Annual Energy Efficiency Resources
- **Seasonal Capacity Performance Resources**
  - **Summer-Period Demand Resources.** A demand resource that is required to be available on any day from June through October and the following May of the delivery year for an unlimited number of interruptions. Summer period DR is required to be capable of maintaining each interruption between the hours of 10:00 a.m. to 10:00 p.m. EPT.
  - **Summer-Period Energy Efficiency Resources.** A project designed to achieve a continuous (during summer peak periods) reduction in electric energy consumption during peak periods that is not reflected in the peak load forecast for the delivery year for which the energy efficiency resource is proposed, and that is fully implemented at all times during the relevant delivery year, without any requirement of notice, dispatch, or operator intervention. The peak period definition for the summer-period efficiency resource type includes the period from the hour ending 15:00 EPT and the hour ending 18:00 EPT from June through August, excluding weekends and federal holidays.

As shown in Table 5-11, Table 5-12, and Table 5-13, capacity in the RPM load management programs was 10,586.0 MW for June 1, 2020, as a result of cleared capacity for demand resources and energy efficiency resources in RPM auctions for the 2020/2021 Delivery Year (13,015.2 MW) less replacement capacity (2,429.2 MW).

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Table 5-11 RPM load management statistics by LDA: June 1, 2018 to June 1, 2021[78 79 80]

		UCAP (MW)														
		RTO	MAAC	EMAAC	SWMAAC	DPL South	PSEG	PSEG North	Pepco	ATSI	ATSI Cleveland	ComEd	BGE	PPL	DAY	DEOK
01-Jun-18	DR cleared	11,435.4	4,361.9	1,707.2	1,226.4	86.8	389.9	139.2	559.3	1,034.3	287.2	1,895.2	667.1	716.2		
	EE cleared	2,296.3	706.8	315.9	317.6	9.2	102.0	45.2	186.1	184.4	33.2	807.4	131.5	43.1		
	DR net replacements	(3,182.4)	(1,268.4)	(584.3)	(199.5)	(52.4)	(150.9)	(43.6)	(25.6)	(261.0)	(136.7)	(430.0)	(173.9)	(220.0)		
	EE net replacements	248.8	163.0	45.5	107.6	1.1	22.4	9.1	(8.9)	14.7	4.7	29.0	116.5	5.4		
	RPM load management	10,798.1	3,963.3	1,484.3	1,452.1	44.7	363.4	149.9	710.9	972.4	188.4	2,301.6	741.2	544.7		
01-Jun-19	DR cleared	10,703.1	3,878.9	1,659.2	817.0	91.3	381.2	176.5	554.6	1,047.0	333.9	1,759.9	262.4	741.4		
	EE cleared	2,528.5	821.4	395.3	301.7	7.8	134.5	52.8	170.0	204.8	41.7	792.9	131.7	72.7		
	DR net replacements	(2,138.8)	(1,004.2)	(468.8)	(129.0)	(40.9)	(141.5)	(86.6)	(74.8)	(130.3)	(123.1)	(143.0)	(54.2)	(208.9)		
	EE net replacements	(50.0)	(24.1)	4.7	3.3	(0.2)	2.7	9.1	2.2	3.4	0.0	0.0	1.1	(20.4)		
	RPM load management	11,042.8	3,672.0	1,590.4	993.0	58.0	376.9	151.8	652.0	1,124.9	252.5	2,409.8	341.0	584.8		
01-Jun-20	DR cleared	9,445.7	2,829.1	1,168.9	485.8	72.6	339.0	152.7	236.3	951.7	231.9	1,657.3	249.5	616.6	241.5	184.7
	EE cleared	3,569.5	1,288.8	700.3	394.5	28.8	246.1	111.3	196.2	356.0	72.9	852.0	198.3	111.4	79.5	105.6
	DR net replacements	(2,399.5)	(858.7)	(369.0)	(176.5)	(29.7)	(136.5)	(89.0)	(53.3)	(121.1)	(36.2)	(314.5)	(123.2)	(171.0)	(66.1)	(27.5)
	EE net replacements	(29.7)	(0.5)	(0.3)	5.9	0.0	(6.3)	12.0	(0.6)	(0.2)	0.0	(0.1)	6.5	(5.2)	0.0	(5.0)
	RPM load management	10,586.0	3,258.7	1,499.9	709.7	71.7	442.3	187.0	378.6	1,186.4	268.6	2,194.7	331.1	551.8	254.9	257.8
01-Jun-21	DR cleared	11,419.8	3,454.1	1,381.5	624.9	66.3	410.5	188.6	345.9	1,196.8	272.8	2,073.7	279.0	697.7	227.7	220.5
	EE cleared	4,031.0	1,549.0	853.8	438.6	31.9	351.4	135.1	213.4	330.6	73.7	895.0	225.2	142.0	83.4	114.8
	DR net replacements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	EE net replacements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	RPM load management	15,450.8	5,003.1	2,235.3	1,063.5	98.2	761.9	323.7	559.3	1,527.4	346.5	2,968.7	504.2	839.7	311.1	335.3

78 See OATT Attachment DD § 8.4. The reported DR cleared MW may reflect reductions in the level of committed MW due to relief from Capacity Resource Deficiency Charges.
79 Pursuant to OA § 15.1.6(c), PJM Settlement shall attempt to close out and liquidate forward capacity commitments for PJM Members that are declared in collateral default. The reported replacement transactions may include transactions associated with PJM members that were declared in collateral default.
80 See OATT Attachment DD § 5.14E. The reported DR cleared MW for the 2016/2017, 2017/2018, and 2018/2019 Delivery Years reflect reductions in the level of committed MW due to the Demand Response Legacy Direct Load Control Transition Provision.

Table 5-12 RPM commitments, replacements, and registrations for demand resources: June 1, 2007 to June 1, 2021[81 82 83]

	UCAP (MW)						Registered DR		
	RPM Cleared	Adjustments to Cleared	Net Replacements	RPM Commitments	RPM Commitment Shortage	RPM Commitments Less Commitment Shortage	ICAP (MW)	UCAP Conversion Factor	UCAP (MW)
01-Jun-07	127.6	0.0	0.0	127.6	0.0	127.6	0.0	1.033	0.0
01-Jun-08	559.4	0.0	(40.0)	519.4	(58.4)	461.0	488.0	1.034	504.7
01-Jun-09	892.9	0.0	(474.7)	418.2	(14.3)	403.9	570.3	1.033	589.2
01-Jun-10	962.9	0.0	(516.3)	446.6	(7.7)	438.9	572.8	1.035	592.6
01-Jun-11	1,826.6	0.0	(1,052.4)	774.2	0.0	774.2	1,117.9	1.035	1,156.5
01-Jun-12	8,752.6	(11.7)	(2,253.6)	6,487.3	(34.9)	6,452.4	7,443.7	1.037	7,718.4
01-Jun-13	10,779.6	0.0	(3,314.4)	7,465.2	(30.5)	7,434.7	8,240.1	1.042	8,586.8
01-Jun-14	14,943.0	0.0	(6,731.8)	8,211.2	(219.4)	7,991.8	8,923.4	1.042	9,301.2
01-Jun-15	15,774.8	(321.1)	(4,829.7)	10,624.0	(61.8)	10,562.2	10,946.0	1.038	11,360.0
01-Jun-16	13,284.7	(19.4)	(4,800.7)	8,464.6	(455.4)	8,009.2	8,961.2	1.042	9,333.4
01-Jun-17	11,870.7	0.0	(3,870.8)	7,999.9	(30.3)	7,969.6	8,681.4	1.039	9,016.3
01-Jun-18	11,435.4	0.0	(3,182.4)	8,253.0	(1.0)	8,252.0	8,512.0	1.091	9,282.4
01-Jun-19	10,703.1	0.0	(2,138.8)	8,564.3	(0.4)	8,563.9	9,229.9	1.090	10,056.0
01-Jun-20	9,445.7	0.0	(2,399.5)	7,046.2	(0.1)	7,046.1	7,867.6	1.088	8,561.5
01-Jun-21	11,419.8	0.0	0.0	11,419.8	0.0	11,419.8	0.0	1.087	0.0

Table 5-13 RPM commitments and replacements for energy efficiency resources: June 1, 2007 to June 1, 2021[84 85]

	UCAP (MW)					
	RPM Cleared	Adjustments to Cleared	Net Replacements	RPM Commitments	RPM Commitment Shortage	RPM Commitments Less Commitment Shortage
01-Jun-07	0.0	0.0	0.0	0.0	0.0	0.0
01-Jun-08	0.0	0.0	0.0	0.0	0.0	0.0
01-Jun-09	0.0	0.0	0.0	0.0	0.0	0.0
01-Jun-10	0.0	0.0	0.0	0.0	0.0	0.0
01-Jun-11	76.4	0.0	0.2	76.6	0.0	76.6
01-Jun-12	666.1	0.0	(34.9)	631.2	(5.1)	626.1
01-Jun-13	904.2	0.0	120.6	1,024.8	(13.5)	1,011.3
01-Jun-14	1,077.7	0.0	204.7	1,282.4	(0.2)	1,282.2
01-Jun-15	1,189.6	0.0	335.9	1,525.5	(0.9)	1,524.6
01-Jun-16	1,723.2	0.0	61.1	1,784.3	(0.5)	1,783.8
01-Jun-17	1,922.3	0.0	195.6	2,117.9	(7.4)	2,110.5
01-Jun-18	2,296.3	0.0	248.8	2,545.1	0.0	2,545.1
01-Jun-19	2,528.5	0.0	(50.0)	2,478.5	0.0	2,478.5
01-Jun-20	3,569.5	0.0	(29.7)	3,539.8	(0.1)	3,539.7
01-Jun-21	4,031.0	0.0	0.0	4,031.0	0.0	4,031.0

81 See OATT Attachment DD § 8.4. The reported DR adjustments to cleared MW include reductions in the level of committed MW due to relief from Capacity Resource Deficiency Charges.

82 See OATT Attachment DD § 5.14C. The reported DR adjustments to cleared MW for the 2015/2016 and 2016/2017 Delivery Years include reductions in the level of committed MW due to the Demand Response Operational Resource Flexibility Transition Provision.

83 See OATT Attachment DD § 5.14E. The reported DR adjustments to cleared MW for the 2016/2017, 2017/2018, and 2018/2019 Delivery Years include reductions in the level of committed MW due to the Demand Response Legacy Direct Load Control Transition Provision.

84 Pursuant to the OA § 15.1.6(c), PJM Settlement shall close out and liquidate all forward positions of PJM members that are declared in default. The replacement transactions reported for the 2014/2015 Delivery Year included transactions associated with RTP Controls, Inc., which was declared in collateral default on March 9, 2012.

85 Effective with the 2019/2020 Delivery Year, available capacity from an EE Resource can be used to replace only EE Resource commitments. This rule change and related EE add back rule changes were endorsed at the December 17, 2015, meeting of the PJM Markets and Reliability Committee.

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Market Conduct

Offer Caps and Offer Floors

Market power mitigation measures were applied to capacity resources such that the sell offer was set equal to the defined offer cap when the capacity market seller failed the market structure test for the auction, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, would have increased the market clearing price.[86] [87] [88] For Base Capacity, offer caps are defined in the PJM Tariff as avoidable costs less PJM market revenues, or opportunity costs based on the potential sale of capacity in an external market. For Capacity Performance Resources, offer caps are defined in the PJM Tariff as the applicable zonal net Cost of New Entry (CONE) times (B) where B is the average of the Balancing Ratios (B) during the Performance Assessment Hours in the three consecutive calendar years that precede the base residual auction for such delivery year, unless net avoidable costs exceed this level, or opportunity costs based on the potential sale of capacity in an external market exceed this level. For RPM Third Incremental Auctions, capacity market sellers may elect, for Base Capacity offers, an offer cap equal to 1.1 times the BRA clearing price for the relevant LDA and delivery year or, for Capacity Performance offers, an offer cap equal to the greater of the net CONE for the relevant LDA and delivery year or 1.1 times the BRA clearing price for the relevant LDA and delivery year.

Avoidable costs are the costs that a generation owner would not incur if the generating unit did not operate for one year, in particular the delivery year.[89] In the calculation of avoidable costs, there is no presumption that the unit would retire as the alternative to operating, although that possibility could be reflected if the owner documented that retirement was the alternative. Avoidable costs may also include annual capital recovery associated with investments required to maintain a unit as a generation capacity resource, termed Avoidable Project Investment Recovery (APIR). Avoidable cost based offer caps are defined to be net of revenues from all other PJM markets and unit-specific bilateral contracts. For Capacity Performance Resources, avoidable cost based offer caps are defined to be net of revenues from all other PJM markets and unit-specific bilateral contracts and expected bonus performance payments/nonperformance charges.[90] Capacity resource owners could provide ACR data by providing their own unit-specific data or, for delivery years prior to 2020/2021, by selecting the default ACR values. The specific components of avoidable costs are defined in the PJM Tariff.[91]

Effective for the 2018/2019 and subsequent delivery years, the ACR definition includes two additional components, Avoidable Fuel Availability Expenses (AFAE) and Capacity Performance Quantifiable Risk (CPQR).[92] AFAE is available for Capacity Performance Resources. AFAE is defined to include expenses related to fuel availability and delivery. CPQR is available for Capacity Performance Resources and, for the 2018/2019 and 2019/2020 Delivery Years, Base Capacity Resources. CPQR is defined to be the quantifiable and reasonably supported cost of mitigating the risks of nonperformance associated with submission of an offer.

The opportunity cost option allows capacity market sellers to offer based on a documented price available in a market external to PJM, subject to export limits. If the relevant RPM market clears above the opportunity cost, the generation capacity resource is sold in the RPM market. If the opportunity cost is greater than the clearing price and the generation capacity resource does not clear in the RPM market, it is available to sell in the external market.

Calculation of Offer Caps

The competitive offer of a Capacity Performance resource is based on a market seller's expectations of a number of variables, some of which are resource specific: the resource's net going forward costs (Net ACR); and the resource's

86 See OATT Attachment DD § 6.5.
87 Prior to November 1, 2009, existing DR and EE resources were subject to market power mitigation in RPM Auctions. See 129 FERC ¶ 61,081 at P 30 (2009).
88 Effective January 31, 2011, the RPM rules related to market power mitigation were changed, including revising the definition for Planned Generation Capacity Resource and creating a new definition for Existing Generation Capacity Resource for purposes of the must offer requirement and market power mitigation, and treating a proposed increase in the capability of a Generation Capacity Resource the same in terms of mitigation as a Planned Generation Capacity Resource. See 134 FERC ¶ 61,065 (2011).
89 OATT Attachment DD § 6.8 (b).
90 For details on the competitive offer of a capacity performance resource, see "Analysis of the 2021/2022 RPM Base Residual Auction—Revised," <http://www.monitoringanalytics.com/reports/Reports/2018/IMM_Analysis_of_the_20212022_RPM_BRA_Revised_20180824.pdf> (August 24, 2018).
91 OATT Attachment DD § 6.8(a).
92 151 FERC ¶ 61,208.

performance during performance assessment intervals (A) in the delivery year.[93]

The competitive offer of a Capacity Performance resource is also based on a market seller's expectations of system level variables: the number of performance assessment intervals (PAI) in a delivery year (H) where the resource is located; the level of performance required to meet its capacity obligation during those performance assessment intervals, measured as the average Balancing Ratio (B); and the level of the bonus performance payment rate (CPBR) compared to the nonperformance charge rate (PPR). The level of bonus performance payment rate depends on the level of underperforming MW net of the underperforming MW excused by PJM during performance assessment hours for reasons defined in the PJM OATT.[94]

The default offer cap defined in the PJM tariff, Net CONE times the average Balancing Ratio, is based on a number of assumptions:

1. The Net ACR of a resource is less than its expected energy only bonuses:

$$ACR \leq \sum_{i=1}^{H}(CPBR_i \times A_i)$$

$$or\ ACR \leq \left(\frac{1}{12}\right)(CPBR \times H \times \bar{A})$$

2. The expected number of performance assessment intervals equals 360. (H = 360 intervals, or 12 hours)
3. The expected value of the bonus performance payment rate (CPBR) is equal to the nonperformance charge rate (PPR)
4. The average expected performance of the resource during performance assessment hours ($\bar{A}$)

The competitive offer of such a resource is:

$$p = \left(\frac{1}{12}\right)(CPBR \times H \times \bar{A} + PPR \times H \times (\bar{B} - \bar{A}))$$

In other words, the competitive offer of such a resource is the opportunity cost of taking on the capacity obligation which equals the sum of the energy only bonuses it would have earned $(CPBR \times H \times \bar{A})/12$ and the net nonperformance charges it would incur by taking on the capacity obligation $(PPR \times H \times (\bar{B} - \bar{A})/12)$. Both the components are proportional to the expected number of performance assessment intervals. If the expected number of performance assessment intervals (*H*) is significantly lower than the value used to determine the nonperformance charge rate (PPR), the opportunity of earning bonuses as an energy only resource, as well as the net nonperformance charges incurred by taking on a capacity obligation are lower. Under such a scenario, the likelihood that that the resource's Net ACR is lower than the expected energy only bonuses is reduced. For resources whose Net ACR is greater than the expected energy only bonuses, the competitive offer is the Net ACR adjusted with any capacity performance bonuses or nonperformance charges they expect to incur during the delivery year.

This means that when the expected number of performance assessment intervals are lower than the value used to determine the nonperformance charge rate (360 intervals, or 30 hours), the current default offer cap of Net CONE times B overstates the competitive offer and the market seller offer cap.

The recent history of a low number of emergency actions in PJM reflect the improvements to generator performance with the capacity performance design, the reduction in actual and expected pool wide outage rates as a result of new units added to the system and the retirement of old units, the upward biased peak load forecasts used in RPM, and the high reserve margins in capacity.[95] [96] Given these developments, the assumption that there would be 30 hours of emergency actions in a year that would trigger performance assessment intervals is unsupported. Since the nonperformance charge rate

93 The model is only applicable to generation resources and storage resources that have an annual obligation to perform with very limited specific excuses as defined in the PJM OATT.
94 OATT Attachment DD § 10A (d).

95 PJM experienced only one emergency event since April 2014 that triggered a PAI in an area that at least encompasses a PJM transmission zone. On October 2, 2019, PJM declared a pre-emergency load management action that triggered PAIs in four zones for a period of two hours or 24 five minute intervals.
96 See Table 5-7.

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is defined in the tariff as net CONE divided by 30 hours, the adjusted default offer cap to reflect a lower estimate for the number of PAIs is much lower than net CONE times B.

In the 2021/2022 RPM Base Residual Auction, net CONE times B exceeded the actual competitive offer level of a Low ACR resource that the default offer cap is based on.[97] While most participants offered in the 2021/2022 RPM Base Residual Auction at competitive levels based on their expectation of the number of performance assessment hours and projected net revenues, some market participants did not offer competitively and affected the market clearing prices.

MOPR

Effective April 12, 2011, the RPM Minimum Offer Price Rule (MOPR) was changed.[98] The changes to the MOPR included updating the calculation of the net Cost of New Entry (CONE) for Combined Cycle (CC) and Combustion Turbine (CT) plants which is used as a benchmark value in assessing the competitiveness of a sell offer, increasing the percentage value used in the screen to 90 percent for CC and CT plants, eliminating the net-short requirement as a prerequisite for applying the MOPR, eliminating the impact screen, revising the process for reviewing proposed exceptions to the defined minimum sell offer price, and clarifying which resources are subject to the MOPR along with the duration of mitigation. Subsequent FERC Orders revised the MOPR, including clarification on the duration of mitigation, which resources are subject to MOPR, and the MOPR review process.[99]

Effective May 3, 2013, the RPM Minimum Offer Price Rule (MOPR) was changed again.[100] The changes to the MOPR included establishing Competitive Entry and Self Supply Exemptions while also retaining the unit specific exception process for those that do not qualify for the Competitive Entry or Self Supply Exemptions; changing the applicability of MOPR to include only combustion turbine, combined cycle, integrated gasification combined cycle (IGCC) technologies while excluding units primarily fueled with landfill gas or cogeneration units which are certified or self-certified as Qualifying Facilities (QFs); changing the applicability to increases in installed capacity of 20.0 MW or more combined for all units at a single point of interconnection to the transmission system; changing the applicability to include the full capability of repowering of plants based on combustion turbine, combined cycle, IGCC technology; increasing the screen from 90 percent to 100 percent of the applicable net CONE values; and broadening the region subject to MOPR to the entire RTO from modeled LDAs only.

Effective December 8, 2017, FERC issued an order on remand rejecting PJM's MOPR proposal in Docket No. ER13-535, and as a result, the rules that were in effect prior to PJM's December 7, 2012, MOPR filing were reinstated. These changes include eliminating the Competitive Entry and Self Supply Exemptions and retaining only the Unit Specific Exception request; narrowing the region subject to MOPR from the entire RTO to only modeled LDAs; eliminating the 20.0 MW threshold for applicability; decreasing the screen from 90 percent to 100 percent of the applicable net CONE values; redefining the applicability criteria to exclude nuclear, coal, IGCC, hydroelectric, wind and solar facilities; modifying the duration of mitigation criteria from clearing in a prior delivery year to clearing in any delivery year; and changing the procedural deadlines.[101]

By order issued December 19, 2019, the RPM Minimum Offer Price Rule (MOPR) was modified.[102] The rules applying to natural gas fired capacity resources without state subsidies were retained. The changes include expanding the MOPR to new or existing state subsidized capacity resources; establishing a competitive exemption for new and existing resources other than natural gas fired resources while also allowing a resource specific exception process for those that do not qualify for the competitive exemption; defining limited categorical exemptions for renewable resources participating in renewable portfolio standards (RPS) programs, self supply, DR, EE, and capacity storage; defining the region subject to MOPR for capacity resources with state subsidy as the entire RTO; and defining the default offer price floor for capacity

97 See Monitoring Analytics, LLC "Analysis of the 2021/2022 RPM Base Residual Auction—Revised," at Attachment B <http://www.monitoringanalytics.com/reports/Reports/2018/IMM_Analysis_of_the_20212022_RPM_BRA_Revised_20180824.pdf> (August 24, 2018).
98 135 FERC ¶ 61,022 (2011).
99 135 FERC ¶ 61,022 (2011), *order on reh'g*, 137 FERC ¶ 61,145 (2011).
100 143 FERC ¶ 61,090 (2013).
101 161 FERC ¶ 61,252 (2017).
102 169 FERC ¶ 61,239 (2019), *order denying reh'g*, 171 FERC ¶ 61,035 (2020).

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resources with state subsidies as 100 percent of the applicable net CONE or net ACR values.

2021/2022 RPM Second Incremental Auction

As shown in Table 5-14, 276 generation resources submitted Capacity Performance offers in the 2021/2022 RPM Third Incremental Auction. Unit specific offer caps were calculated for zero generation resources (0.0 percent). Of the 276 generation resources, 241 generation resources had the net CONE times B offer cap (87.3 percent), 20 generation resources had uncapped planned uprates plus net CONE times B offer cap for the existing portion of the units (7.2 percent), 10 Planned Generation Capacity Resources had uncapped offers (3.6 percent), and the remaining five generation resources were price takers (1.8 percent). Market power mitigation was applied to the Capacity Performance sell offers of zero generation resources, including 0.0 MW.

MOPR Statistics

Market power mitigation measures are applied to MOPR Screened Generation Resources such that the sell offer is set equal to the MOPR Floor Offer Price when the submitted sell offer is less than the MOPR Floor Offer Price and an exemption or exception was not granted, or the sell offer is set equal to the agreed upon minimum level of sell offer when the sell offer is less than the agreed upon minimum level of sell offer based on a Unit-Specific Exception.

As shown in Table 5-15, of the 844.4 ICAP MW of MOPR Unit-Specific Exception requests for the 2021/2022 RPM Second Incremental Auction, requests for 844.4 MW were granted.

Table 5-14 ACR statistics: RPM auctions conducted in third quarter, 2020

	2021/2022 Second Incremental Auction	
Offer Cap/Mitigation Type	Number of Generation Resources	Percent of Generation Resources Offered
Default ACR	NA	NA
Unit specific ACR (APIR)	0	0.0%
Unit specific ACR (APIR and CPQR)	0	0.0%
Unit specific ACR (non-APIR)	0	0.0%
Unit specific ACR (non-APIR and CPQR)	0	0.0%
Opportunity cost input	0	0.0%
Default ACR and opportunity cost	NA	NA
Net CONE times B	241	87.3%
Offer cap of 1.1 times BRA clearing price elected	NA	NA
Uncapped planned uprate and default ACR	NA	NA
Uncapped planned uprate and opportunity cost	0	0.0%
Uncapped planned uprate and Net CONE times B	20	7.2%
Uncapped planned uprate and price taker	0	0.0%
Uncapped planned uprate and 1.1 times BRA clearing price elected	NA	NA
Uncapped planned generation resources	10	3.6%
Existing generation resources as price takers	5	1.8%
Total Generation Capacity Resources offered	276	100.0%

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Table 5-15 MOPR statistics: RPM auctions conducted in third quarter, 2020[103]

		Number of Requests	ICAP (MW)			UCAP (MW)	
		(Company-Plant Level)	Requested	Granted	Offered	Offered	Cleared
2021/2022 Second Incremental Auction	Unit-Specific Exception	19	844.4	844.4	16.2	16.0	0.0
	Other MOPR Screened Generation Resources	0	0.0	0.0	140.1	137.0	0.0
	Total	19	844.4	844.4	156.3	153.0	0.0

Replacement Capacity[104]

Table 5-16 shows the committed and replacement capacity for all capacity resources for June 1 of each year from 2007 through 2021. The 2021 numbers are not final.

Table 5-16 RPM commitments and replacements for all Capacity Resources: June 1, 2007 to June 1, 2021

	UCAP (MW)					
	RPM Cleared	Adjustments to Cleared	Net Replacements	RPM Commitments	RPM Commitment Shortage	RPM Commitments Less Commitment Shortage
01-Jun-07	129,409.2	0.0	0.0	129,409.2	(8.1)	129,401.1
01-Jun-08	130,629.8	0.0	(766.5)	129,863.3	(246.3)	129,617.0
01-Jun-09	134,030.2	0.0	(2,068.2)	131,962.0	(14.7)	131,947.3
01-Jun-10	134,036.2	0.0	(4,179.0)	129,857.2	(8.8)	129,848.4
01-Jun-11	134,182.6	0.0	(6,717.6)	127,465.0	(79.3)	127,385.7
01-Jun-12	141,295.6	(11.7)	(9,400.6)	131,883.3	(157.2)	131,726.1
01-Jun-13	159,844.5	0.0	(12,235.3)	147,609.2	(65.4)	147,543.8
01-Jun-14	161,214.4	(9.4)	(13,615.9)	147,589.1	(1,208.9)	146,380.2
01-Jun-15	173,845.5	(326.1)	(11,849.4)	161,670.0	(1,822.0)	159,848.0
01-Jun-16	179,773.6	(24.6)	(16,157.5)	163,591.5	(924.4)	162,667.1
01-Jun-17	180,590.5	0.0	(13,982.7)	166,607.8	(625.3)	165,982.5
01-Jun-18	175,996.0	0.0	(12,057.8)	163,938.2	(150.5)	163,787.7
01-Jun-19	177,064.2	0.0	(12,300.3)	164,763.9	(9.3)	164,754.6
01-Jun-20	174,023.8	(335.3)	(10,582.7)	163,105.8	(5.7)	163,100.1
01-Jun-21	169,478.0	0.0	(673.5)	168,804.5	0.0	168,804.5

Market Performance

Figure 5-8 shows cleared MW weighted average capacity market prices on a delivery year basis for the entire history of the PJM capacity markets.

Table 5-17 shows RPM clearing prices for all RPM auctions held through the first nine months of 2020, and Table 5-18 shows the RPM cleared MW for all RPM auctions held through the first nine months of 2020.

Figure 5-9 shows the RPM cleared MW weighted average prices for each LDA for the current delivery year and all results for auctions for future delivery years that have been held through the first nine months of 2020. A summary of these weighted average prices is given in Table 5-19.

Table 5-20 shows RPM revenue by delivery year for all RPM auctions held through the first nine months of 2020 based on the unforced MW cleared and the resource clearing prices. In 2019/2020, RPM revenue was $7.1 billion. In 2020/2021, RPM revenue was $7.0 billion.

Table 5-21 shows RPM revenue by calendar year for all RPM auctions held through the first nine months of 2020. In 2018, RPM revenue was $10.3 billion. In 2019, RPM revenue was $8.7 billion.

Table 5-22 shows the RPM annual charges to load. For the 2018/2019 Delivery Year, RPM annual charges to load were $11.0 billion. For the 2020/2021 Delivery Year, annual charges to load are $7.0 billion.

103 There were additional MOPR Screened Generation Resources for which no exceptions or exemptions were requested and to which the MOPR floor was applied. Some numbers are not reported as a result of PJM confidentiality rules.
104 For more details on replacement capacity, see "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2019," <http://www.monitoringanalytics.com/reports/Reports/2019/IMM_Analysis_of_Replacement_Capacity_for_RPM_Commitments_June_1_2007_to_June_1_2019_20190913.pdf> (September 13, 2019).

Table 5-17 Capacity market clearing prices: 2007/2008 through 2021/2022 RPM Auctions

		RPM Clearing Price ($ per MW-day)												
	Product Type	RTO	MAAC	APS	PPL	EMAAC	SWMAAC	DPL South	PSEG	PSEG North	Pepco	ATSI	ComEd	BGE
2019/2020 BRA	Base Capacity	$80.00	$80.00	$80.00	$80.00	$99.77	$80.00	$99.77	$99.77	$99.77	$80.00	$80.00	$182.77	$80.30
2019/2020 BRA	Base Capacity DR/EE	$80.00	$80.00	$80.00	$80.00	$99.77	$80.00	$99.77	$99.77	$99.77	$0.01	$80.00	$182.77	$80.30
2019/2020 BRA	Capacity Performance	$100.00	$100.00	$100.00	$100.00	$119.77	$100.00	$119.77	$119.77	$119.77	$100.00	$100.00	$202.77	$100.30
2019/2020 First Incremental Auction	Base Capacity	$15.00	$15.00	$15.00	$15.00	$22.22	$15.00	$22.22	$22.22	$22.22	$15.00	$15.00	$15.00	$15.00
2019/2020 First Incremental Auction	Base Capacity DR/EE	$15.00	$15.00	$15.00	$15.00	$22.22	$15.00	$22.22	$22.22	$22.22	$15.00	$15.00	$15.00	$15.00
2019/2020 First Incremental Auction	Capacity Performance	$51.33	$51.33	$51.33	$51.33	$58.55	$51.33	$58.55	$58.55	$58.55	$51.33	$51.33	$51.33	$51.33
2019/2020 Second Incremental Auction	Base Capacity	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$32.14
2019/2020 Second Incremental Auction	Base Capacity DR/EE	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$32.14
2019/2020 Second Incremental Auction	Capacity Performance	$32.87	$32.87	$32.87	$32.87	$32.87	$32.87	$32.87	$32.87	$32.87	$32.87	$32.87	$32.87	$55.00
2019/2020 Third Incremental Auction	Base Capacity	$21.35	$21.35	$21.35	$21.35	$21.35	$21.35	$21.35	$21.35	$21.35	$21.35	$21.35	$21.35	$21.35
2019/2020 Third Incremental Auction	Base Capacity DR/EE	$21.35	$21.35	$21.35	$21.35	$21.35	$21.35	$21.35	$21.35	$21.35	$20.00	$21.35	$21.35	$21.35
2019/2020 Third Incremental Auction	Capacity Performance	$28.35	$28.35	$28.35	$28.35	$28.35	$28.35	$28.35	$28.35	$28.35	$28.35	$28.35	$28.35	$28.35
2020/2021 BRA	Capacity Performance	$76.53	$86.04	$76.53	$86.04	$187.87	$86.04	$187.87	$187.87	$187.87	$86.04	$76.53	$188.12	$86.04
2020/2021 First Incremental Auction	Capacity Performance	$42.90	$42.90	$42.90	$42.90	$42.90	$42.90	$42.90	$42.90	$42.90	$42.90	$42.90	$42.90	$42.90
2020/2021 Second Incremental Auction	Capacity Performance	$20.25	$20.25	$20.25	$20.25	$20.25	$20.25	$20.25	$20.25	$20.25	$20.25	$20.25	$20.25	$20.25
2020/2021 Third Incremental Auction	Capacity Performance	$10.00	$15.25	$10.00	$15.25	$15.25	$15.25	$15.25	$15.25	$15.25	$15.25	$10.00	$10.00	$15.25
2021/2022 BRA	Capacity Performance	$140.00	$140.00	$140.00	$140.00	$165.73	$140.00	$165.73	$204.29	$204.29	$140.00	$171.33	$195.55	$200.30
2021/2022 First Incremental Auction	Capacity Performance	$23.00	$23.00	$23.00	$23.00	$25.00	$23.00	$25.00	$45.00	$219.00	$23.00	$23.00	$23.00	$60.00
2021/2022 Second Incremental Auction	Capacity Performance	$10.26	$10.26	$10.26	$10.26	$15.37	$10.26	$15.37	$125.00	$125.00	$10.26	$10.26	$10.26	$70.00

Table 5-18 Capacity market cleared MW: 2007/2008 through 2021/2022 RPM Auctions[105]

		UCAP (MW)												
Delivery Year	Auction	RTO	MAAC	APS	PPL	EMAAC	DPL South	PSEG	PSEG North	Pepco	ATSI	ComEd	BGE	TOTAL
2019/2020	BASE	60,061.8	9,996.2	9,066.6	12,754.9	20,382.4	1,598.5	5,583.1	3,228.9	6,971.7	10,291.1	22,971.4	4,422.9	167,329.5
2019/2020	FIRST	784.5	249.4	39.3	157.7	78.7	11.7	10.6	28.8	43.6	147.5	711.4	31.9	2,295.1
2019/2020	SECOND	442.9	160.4	30.1	146.2	210.1	21.2	38.1	44.8	41.9	263.6	105.8	107.5	1,612.6
2019/2020	THIRD	1,608.0	440.9	429.4	1,216.6	265.7	2.4	180.4	23.2	83.6	454.2	867.4	255.2	5,827.0
2020/2021	BASE	56,012.4	11,413.2	8,990.6	14,398.2	19,978.5	1,647.2	5,041.2	2,975.4	6,410.0	9,925.9	23,960.3	4,021.1	164,773.9
2020/2021	FIRST	1,265.6	331.0	144.2	83.4	76.2	38.9	105.8	32.0	97.8	666.9	644.4	38.7	3,524.8
2020/2021	SECOND	447.2	206.9	53.0	30.7	302.9	28.4	29.5	48.8	35.4	366.2	194.6	160.3	1,903.8
2020/2021	THIRD	1,106.6	569.7	118.7	89.0	194.1	33.1	423.0	137.0	93.1	554.3	127.7	39.8	3,486.0
2021/2022	BASE	55,642.6	12,565.1	10,136.1	15,368.6	19,857.3	1,673.8	4,667.2	3,134.1	6,546.1	8,010.5	22,358.1	3,667.8	163,627.3
2021/2022	FIRST	281.7	200.4	45.9	27.2	119.0	15.3	18.3	79.1	207.9	739.3	360.4	48.7	2,143.2
2021/2022	SECOND	1,307.8	335.8	30.3	55.4	129.9	39.3	97.0	98.1	75.7	1,216.8	205.9	115.5	3,707.5

105 The MW values in this table refer to rest of LDA or RTO values, which are net of nested LDA values.

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Table 5-19 Weighted average clearing prices by zone: 2018/2019 through 2021/2022

	Weighted Average Clearing Price ($ per MW-day)			
LDA	2018/2019	2019/2020	2020/2021	2021/2022
RTO				
AEP	$158.20	$93.63	$74.42	$137.02
APS	$158.20	$93.63	$74.42	$137.02
ATSI	$148.42	$92.97	$69.75	$149.70
Cleveland	$158.68	$89.17	$68.93	$106.96
ComEd	$199.02	$188.90	$182.15	$191.17
DAY	$158.20	$93.63	$72.42	$138.19
DEOK	$158.20	$93.63	$121.24	$133.54
DLCO	$158.20	$93.63	$74.42	$137.02
Dominion	$158.20	$93.63	$74.42	$137.02
EKPC	$158.20	$93.63	$74.42	$137.02
MAAC				
EMAAC				
AECO	$214.31	$112.48	$182.04	$164.07
DPL	$214.31	$112.48	$182.04	$164.07
DPL South	$211.38	$115.95	$178.65	$161.07
JCPL	$214.31	$112.48	$182.04	$164.07
PECO	$214.31	$112.48	$182.04	$164.07
PSEG	$210.92	$110.56	$165.74	$199.70
PSEG North	$211.71	$116.03	$176.45	$202.27
RECO	$214.31	$112.48	$182.04	$164.07
SWMAAC				
BGE	$141.58	$88.20	$80.71	$189.98
Pepco	$144.90	$90.59	$84.24	$134.58
WMAAC				
Met-Ed	$152.65	$93.81	$81.85	$136.11
PENELEC	$152.65	$93.81	$81.85	$136.11
PPL	$147.90	$88.53	$85.07	$139.16

Table 5-20 RPM revenue by delivery year: 2007/2008 through 2021/2022[106]

Delivery Year	Weighted Average RPM Price ($ per MW-day)	Weighted Average Cleared UCAP (MW)	Days	RPM Revenue
2007/2008	$89.78	129,409.2	366	$4,252,287,381
2008/2009	$127.67	130,629.8	365	$6,087,147,586
2009/2010	$153.37	134,030.2	365	$7,503,218,157
2010/2011	$172.71	134,036.2	365	$8,449,652,496
2011/2012	$108.63	134,182.6	366	$5,335,087,023
2012/2013	$75.08	141,283.9	365	$3,871,714,635
2013/2014	$116.55	159,844.5	365	$6,799,778,047
2014/2015	$126.40	161,205.0	365	$7,437,267,646
2015/2016	$160.01	173,519.4	366	$10,161,726,902
2016/2017	$121.84	179,749.0	365	$7,993,888,695
2017/2018	$141.19	180,590.5	365	$9,306,676,719
2018/2019	$172.09	175,996.0	365	$11,054,943,851
2019/2020	$109.82	177,064.2	366	$7,116,815,360
2020/2021	$111.07	173,688.5	365	$7,041,524,517
2021/2022	$151.15	169,478.0	365	$9,349,894,658

Table 5-21 RPM revenue by calendar year: 2007 through 2022[107]

Year	Weighted Average RPM Price ($ per MW-day)	Weighted Average Cleared UCAP (MW)	Effective Days	RPM Revenue
2007	$89.78	75,665.5	214	$2,486,310,108
2008	$111.93	130,332.1	366	$5,334,880,241
2009	$142.74	132,623.5	365	$6,917,391,702
2010	$164.71	134,033.7	365	$8,058,113,907
2011	$135.14	133,907.1	365	$6,615,032,130
2012	$89.01	138,561.1	366	$4,485,656,150
2013	$99.39	152,166.0	365	$5,588,442,225
2014	$122.32	160,642.2	365	$7,173,539,072
2015	$146.10	168,147.0	365	$9,018,343,604
2016	$137.69	177,449.8	366	$8,906,998,628
2017	$133.19	180,242.4	365	$8,763,578,112
2018	$159.31	177,896.7	365	$10,331,688,133
2019	$135.58	176,338.6	365	$8,734,613,179
2020	$110.55	175,368.7	366	$7,084,072,778
2021	$134.57	171,219.9	365	$8,394,925,093
2022	$151.15	70,112.8	151	$3,868,038,612

106 The results for the ATSI Integration Auctions are not included in this table.
107 The results for the ATSI Integration Auctions are not included in this table.

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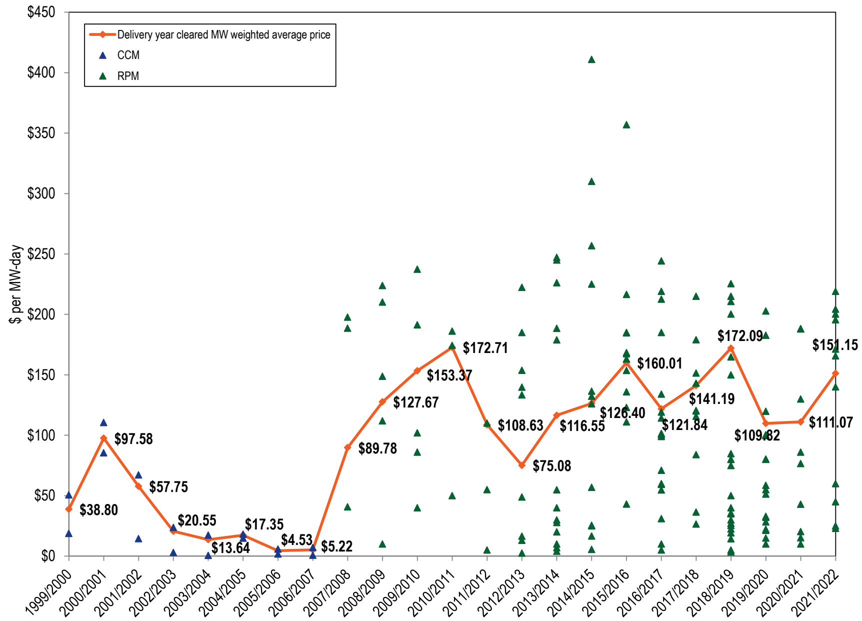
Figure 5-8 History of capacity prices: 1999/2000 through 2021/2022[108]



108 The 1999/2000 through 2006/2007 capacity prices are CCM combined market, weighted average prices. The 2007/2008 through 2021/2022 capacity prices are RPM weighted average prices. The CCM data points plotted are cleared MW weighted average prices for the daily and monthly markets by delivery year. The RPM data points plotted are RPM resource clearing prices. For the 2014/2015 and subsequent delivery years, only the prices for Annual Resources or Capacity Performance Resources are plotted.

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Figure 5-9 Map of RPM capacity prices: 2018/2019 through 2021/2022

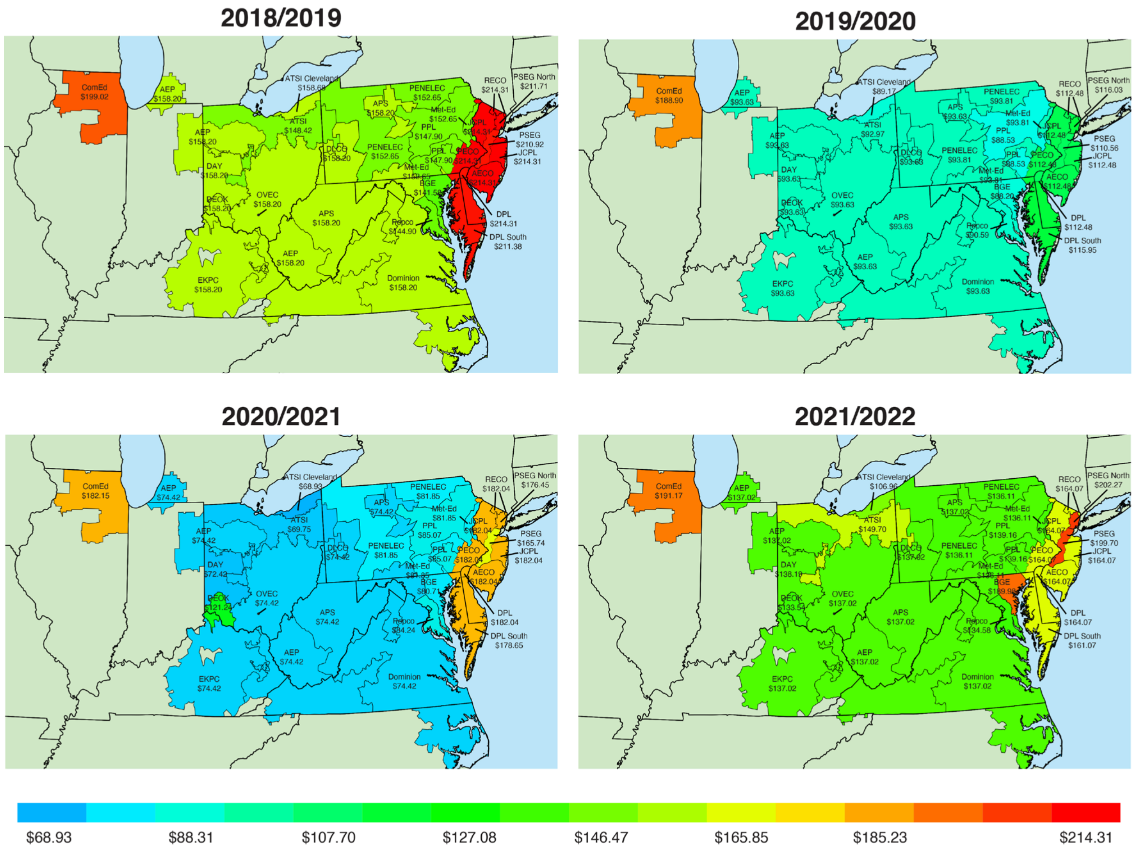

Table 5-22 RPM cost to load: 2019/2020 through 2021/2022 RPM Auctions[109 110 111]

	Zonal Capacity Price ($ per MW-Day)	Zonal CTR Credit Rate ($ per MW-Day)	Net Load Price ($ per MW-day)	UCAP Obligation (MW)	Days	Annual Charges	Charges per Day
2019/2020							
Rest of RTO	$98.07	$0.00	$98.07	89,185.9	366	$3,201,364,940	$8,746,899
Rest of EMAAC	$117.92	$2.35	$115.58	24,415.1	366	$1,032,810,556	$2,821,887
BGE	$97.22	-$0.56	$97.79	7,595.2	366	$271,828,430	$742,701
ComEd	$195.99	$3.43	$192.56	24,985.1	366	$1,760,892,086	$4,811,181
Pepco	$92.90	$0.00	$92.90	7,330.3	366	$249,230,694	$680,958
PSEG	$118.18	$2.35	$115.83	11,281.1	366	$478,247,326	$1,306,687
Total				164,792.8		$6,994,374,033	
2020/2021							
Rest of RTO	$77.31	$0.00	$77.31	69,073.7	365	$1,949,098,489	$5,339,996
Rest of MAAC	$86.98	-$0.08	$87.06	29,555.9	365	$939,246,366	$2,573,278
EMAAC	$187.13	$12.80	$174.32	35,740.4	365	$2,274,098,760	$6,230,408
ComEd	$190.04	$0.12	$189.92	23,744.7	365	$1,645,988,210	$4,509,557
DEOK	$128.73	$24.23	$104.50	5,072.0	365	$193,459,838	$530,027
Total				163,186.7		$7,001,891,663	
2021/2022							
Rest of RTO	$142.71	$0.00	$142.71	81,244.5	365	$4,232,062,441	$11,594,692
Rest of EMAAC	$168.34	$3.44	$164.89	23,999.1	365	$1,444,396,169	$3,957,250
ATSI	$168.49	$7.71	$160.78	13,978.7	365	$820,348,098	$2,247,529
BGE	$205.09	$40.51	$164.58	7,316.9	365	$439,530,736	$1,204,194
ComEd	$198.71	$0.00	$198.71	23,149.9	365	$1,679,053,039	$4,600,145
PSEG	$210.74	$22.72	$188.02	11,275.2	365	$773,794,246	$2,119,984
Total				160,964.3		$9,389,184,729	

Timing of Unit Retirements

Generation owners that want to deactivate a unit, either to mothball or permanently retire, must provide notice to PJM and the MMU at least 90 days prior to the proposed deactivation date. Generation owners seeking a capacity market must offer exemption for a delivery year must submit their deactivation request no later than the December 1 preceding the Base Residual Auction or 120 days before the start of an Incremental Auction for that delivery year.[112] If no reliability issues are found during PJM's analysis of the retirement's impact on the transmission system, and the MMU finds no market power issues associated with the proposed deactivation, the unit may deactivate at any time thereafter.[113]

Table 5-23 shows the timing of actual deactivation dates and the initially requested deactivation date, for all deactivation requests submitted from January 2018 through September 2020. Of the 69 deactivation requests submitted, 17 units (24.6 percent) deactivated an average of 232 days earlier than their initially requested date; 11 units (15.9 percent) deactivated an average of 84 days later than the originally requested deactivation date; and 22 units (31.9 percent) deactivated on their initially requested date. Eleven (15.9 percent) of the unit deactivations were cancelled an average of 465 days before their scheduled deactivation date, and 8 (11.6 percent) of the unit deactivations have not yet reached their target retirement date.

Table 5-23 Timing of actual unit deactivations compared to initially requested deactivation date: Requests submitted January 2018 through September 2020

	Number of Units	Percent	Average Deviation from Originally Requested Date
Early	17	24.6%	(232)
Late	11	15.9%	84
On time	22	31.9%	0
Cancelled	11	15.9%	(465)
Pending	8	11.6%	-
Total	69	100.0%	-

109 The RPM annual charges are calculated using the rounded, net load prices as posted in the PJM RPM auction results.
110 There is no separate obligation for DPL South as the DPL South LDA is completely contained within the DPL Zone. There is no separate obligation for PSEG North as the PSEG North LDA is completely contained within the PSEG Zone. There is no separate obligation for ATSI Cleveland as the ATSI Cleveland LDA is completely contained within the ATSI Zone.
111 The net load prices and obligation MW for 2021/2022 are not finalized.
112 OATT Attachment DD § 6.6(g).
113 OATT Part V §113

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Reliability Must Run (RMR) Service

PJM must make out of market payments to units for Reliability Must Run (RMR) service during periods when a unit that would otherwise have been deactivated is needed for reliability.[114] The need for RMR service reflects a flawed market design and/or planning process problems. If a unit is needed for reliability, the market should reflect a locational value consistent with that need which would result in the unit remaining in service or being replaced by a competitor unit. The planning process should evaluate the impact of the loss of units at risk and determine in advance whether transmission upgrades are required.[115]

When notified of an intended deactivation, the MMU performs a market power study to ensure that the deactivation is economic, not an exercise of market power through withholding, and consistent with competition.[116] PJM performs a system study to determine whether the system can accommodate the deactivation on the desired date, and if not, when it could.[117] If PJM determines that it needs a unit for a period beyond the intended deactivation date, PJM will request a unit to provide RMR service.[118] The PJM market rules do not require an owner to provide RMR service, but owners must provide 90 days advance notice of a proposed deactivation.[119] The owner of a generation capacity resource must provide notice of a proposed deactivation in order to avoid a requirement to offer in RPM auctions.[120] In order to avoid submitting an offer for a unit in the next three-year forward RPM base residual auction, an owner must show "a documented plan in place to retire the resource," including a notice of deactivation filed with PJM, 120 days prior to such auction.[121]

114 OATT Part V §114
115 *See, e.g.*, 140 FERC ¶ 61,237 at P 36 (2012) ("The evaluation of alternatives to an SSR designation is an important step that deserves the full consideration of MISO and its stakeholders to ensure that SSR Agreements are used only as a 'limited, last-resort measure.'"); 118 FERC ¶ 61,243 at P 41 (2007) ("the market participants that pay for the agreements pay out-of-market prices for the service provided under the RMR agreements, which broadly hinders market development and performance.[footnote omitted] As a result of these factors, we have concluded that RMR agreements should be used as a last resort."); 110 FERC ¶ 61,315 at P 40 (2005) ("The Commission has stated on several occasions that it shares the concerns . . . that RMR agreements not proliferate as an alternative pricing option for generators, and that they are used strictly as a last resort so that units needed for reliability receive reasonable compensation.").
116 OATT § 113.2; OATT Attachment M § IV.1.
117 OATT § 113.2.
118 *Id.*
119 OATT § 113.1.
120 OATT Attachment DD § 6.6(g).
121 *Id.*

Under the current rules, a unit providing RMR service can recover its costs under either the deactivation avoidable cost rate (DACR), which is a formula rate, or the cost of service recovery rate. The deactivation avoidable cost rate is designed to permit the recovery of the costs of the unit's "continued operation," termed "avoidable costs," plus an incentive adder.[122] Avoidable costs are defined to mean "incremental expenses directly required for the operation of a generating unit."[123] The incentives escalate for each year of service (first year, 10 percent; second year, 20 percent; third year, 35 percent; fourth year, 50 percent).[124] The rules provide terms for early termination of RMR service and for the repayment of project investment by owners of units that choose to keep units in service after the RMR period ends.[125] Project investment is capped at $2 million, above which FERC approval is required.[126] The cost of service rate is designed to permit the recovery of the unit's "cost of service rate to recover the entire cost of operating the generating unit" if the generation owner files a separate rate schedule at FERC.[127]

122 OATT § 114 (Deactivation Avoidable Credit = ((Deactivation Avoidable Cost Rate + Applicable Adder) * MW capability of the unit * Number of days in the month) – Actual Net Revenues).
123 OATT § 115.
124 *Id.*
125 OATT § 118.
126 OATT §§ 115, 117.
127 OATT § 119.

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Table 5-24 shows units that have provided RMR service to PJM.

Table 5-24 RMR service summary

Unit Names	Owner	ICAP (MW)	Cost Recovery Method	Docket Numbers	Start of Term	End of Term
B.L. England 2	RC Cape May Holdings, LLC	150.0	Cost of Service Recovery Rate	ER17-1083	01-May-17	30-Apr-19
Yorktown 1	Dominion Virginia Power	159.0	Deactivation Avoidable Cost Rate	ER17-750	06-Jan-17	08-Mar-19
Yorktown 2	Dominion Virginia Power	164.0	Deactivation Avoidable Cost Rate	ER17-750	06-Jan-17	08-Mar-19
B.L. England 3	RC Cape May Holdings, LLC	148.0	Cost of Service Recovery Rate	ER17-1083	01-May-17	24-Jan-18
Ashtabula	FirstEnergy Service Company	210.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	11-Apr-15
Eastlake 1	FirstEnergy Service Company	109.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	15-Sep-14
Eastlake 2	FirstEnergy Service Company	109.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	15-Sep-14
Eastlake 3	FirstEnergy Service Company	109.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	15-Sep-14
Lakeshore	FirstEnergy Service Company	190.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	15-Sep-14
Elrama 4	GenOn Power Midwest, LP	171.0	Cost of Service Recovery Rate	ER12-1901	01-Jun-12	01-Oct-12
Niles 1	GenOn Power Midwest, LP	109.0	Cost of Service Recovery Rate	ER12-1901	01-Jun-12	01-Oct-12
Cromby 2 and Diesel	Exelon Generation Company, LLC	203.7	Cost of Service Recovery Rate	ER10-1418	01-Jun-11	01-Jan-12
Eddystone 2	Exelon Generation Company, LLC	309.0	Cost of Service Recovery Rate	ER10-1418	01-Jun-11	01-Jun-12
Brunot Island CT2A, CT2B, CT3 and CC4	Orion Power MidWest, L.P.	244.0	Cost of Service Recovery Rate	ER06-993	16-May-06	05-Jul-07
Hudson 1	PSEG Energy Resources & Trade LLC and PSEG Fossil LLC	355.0	Cost of Service Recovery Rate	ER05-644, ER11-2688	25-Feb-05	08-Dec-11
Sewaren 1-4	PSEG Energy Resources & Trade LLC and PSEG Fossil LLC	453.0	Cost of Service Recovery Rate	ER05-644	25-Feb-05	01-Sep-08

Only two of seven owners have used the deactivation avoidable cost rate approach. The other five owners used the cost of service recovery rate, despite the greater administrative expense.

In each of the cost of service recovery rate filings for RMR service, the scope of recovery permitted under the cost of service approach defined in Section 119 has been a significant issue. Owners have sought to recover fixed costs, incurred prior to the noticed deactivation date, in addition to the cost of operating the generating unit. Owners have cited the cost of service reference to mean that the unit is entitled to file to recover costs that it was unable to recover in the competitive markets, in addition to recovery of costs of actually providing the RMR service.

The cost of service recovery rate approach has been interpreted by the companies using that approach to allow the company to establish a rate base including investment in the existing plant and new investment necessary to provide RMR service and to earn a return on that rate base and receive depreciation of that rate base. Companies developing the cost of service recovery rate have ignored the tariff's limitation to the costs of operating the unit during the RMR service period and have included costs incurred prior to the decision to the deactivate and costs associated with closing the unit that would have been incurred regardless of the RMR service period.[128] In one cost of service recovery rate, the filing included costs that already had been written off on the company's public books.[129] Unit owners have filed for revenues under the cost of service method that substantially exceed the actual incremental costs of providing RMR service.

Because an RMR unit is needed by PJM for reliability reasons, and the provision of RMR service is voluntary in PJM, owners of RMR service have significant market power in establishing the terms of RMR service.

RMR service should be provided to PJM customers at reasonable rates, which reflect the riskless nature of providing such service to owners, the reliability need for such service and the opportunity for owners to be guaranteed

128 See, e.g., FERC Dockets Nos. ER10-1418-000, ER12-1901-000 and ER17-1083-000.
129 See GenOn Filing, Docket No. ER12-1901-000 (May 31, 2012) at Exh. No. GPM-1 at 9:16–21.

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recovery of 100 percent of the actual incremental costs incurred to provide the service plus an incentive markup.

The cost of service recovery rates have been excessive compared to the actual incremental costs of providing RMR service. The DACR method also provides excessive incentives for service longer than a year, given that customers bear the risks.

The MMU recommends elimination of the cost of service recovery rate in OATT Section 119, and that RMR service should be provided under the deactivation avoidable cost rate in Part V.

The MMU also recommends, based in part on its experience with application of the deactivation avoidable cost rate and proceedings filed under Section 119, the following improvements to the DACR provisions:

- Revise the applicable adders in Section 114 to be 15 percent for the second year of RMR service and 20 percent for the provision of RMR service in excess of two years.
- Add true up provisions that ensure that the RMR service provider is reimbursed for, and consumers pay for, the actual incremental costs associated with the RMR service, plus the applicable adder.
- Eliminate the $2 million cap on project investment expenditures.
- Clearly distinguish operating expenses and project investment costs.
- Clarify the tariff language in Section 118 regarding the refund of project investment in the event the RMR unit continues operation beyond the RMR term.

Generator Performance

Generator performance results from the interaction between the physical characteristics of the units and the level of expenditures made to maintain the capability of the units, which in turn is a function of incentives from energy, ancillary services and capacity markets. Generator performance indices include those based on total hours in a period (generator performance factors) and those based on hours when units are needed to operate by the system operator (generator forced outage rates).

Capacity Factor

Capacity factor measures the actual output of a power plant over a period of time compared to the potential output of the unit had it been running at full nameplate capacity for every hour during that period. Table 5-25 shows the capacity factors by unit type in the first nine months of 2019 and 2020. In the first nine months of 2020, nuclear units had a capacity factor of 93.1 percent, compared to 92.7 percent in the first nine months of 2019; combined cycle units had a capacity factor of 55.2 percent in the first nine months of 2020, compared to a capacity factor of 55.0 percent in the first nine months of 2019; all steam units had a capacity factor of 23.3 percent in the first nine months of 2020, compared to 28.7 percent in the first nine months of 2019; coal units had a capacity factor of 25.4 percent in the first nine months of 2020, compared to 31.6 percent in the first nine months of 2019.

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Table 5-25 Capacity factor (By unit type (GWh)): January through September, 2019 and 2020[130 131]

	2019 (Jan-Sep)		2020 (Jan-Sep)		
Unit Type	Generation (GWh)	Capacity Factor	Generation (GWh)	Capacity Factor	Change in 2020 from 2019
Battery	15.1	0.7%	27.0	1.2%	0.5%
Combined Cycle	211,909.2	55.0%	229,071.1	55.2%	0.1%
Single Fuel	180,345.5	57.4%	194,993.4	56.7%	(0.7%)
Dual Fuel	31,563.7	44.7%	34,077.7	48.1%	3.4%
Combustion Turbine	12,167.9	5.3%	15,069.9	6.7%	1.3%
Single Fuel	8,174.8	5.0%	10,573.3	6.5%	1.6%
Dual Fuel	3,993.1	6.4%	4,496.7	7.1%	0.8%
Diesel	200.3	6.2%	188.5	5.6%	(0.7%)
Single Fuel	196.3	7.4%	182.6	6.5%	(0.9%)
Dual Fuel	4.0	0.7%	5.9	1.0%	0.3%
Diesel (Landfill gas)	1,267.2	43.6%	1,182.9	42.6%	(0.9%)
Fuel Cell	163.1	77.9%	170.3	81.0%	3.1%
Nuclear	210,535.4	92.7%	207,426.7	93.1%	0.4%
Pumped Storage Hydro	4,597.2	10.6%	4,839.4	11.1%	0.5%
Run of River Hydro	8,818.5	33.8%	8,108.9	30.9%	(2.8%)
Solar	2,218.6	21.0%	2,977.8	20.7%	(0.3%)
Steam	166,172.0	28.7%	127,877.2	23.3%	(5.4%)
Biomass	4,563.1	55.2%	4,203.5	53.0%	(2.2%)
Coal	156,702.4	31.6%	118,216.2	25.4%	(6.2%)
Single Fuel	153,788.9	32.5%	116,152.6	26.2%	(6.3%)
Dual Fuel	2,913.5	13.1%	2,063.5	9.5%	(3.6%)
Natural Gas	4,807.9	35.5%	5,384.4	37.1%	1.6%
Single Fuel	354.1	41.2%	344.7	42.4%	1.2%
Dual Fuel	4,453.8	21.4%	5,039.7	23.3%	1.8%
Oil	98.6	0.4%	73.0	0.5%	0.1%
Wind	16,973.8	27.2%	17,986.2	25.8%	(1.4%)
Total	635,041.1	40.5%	614,930.3	39.1%	(1.4%)

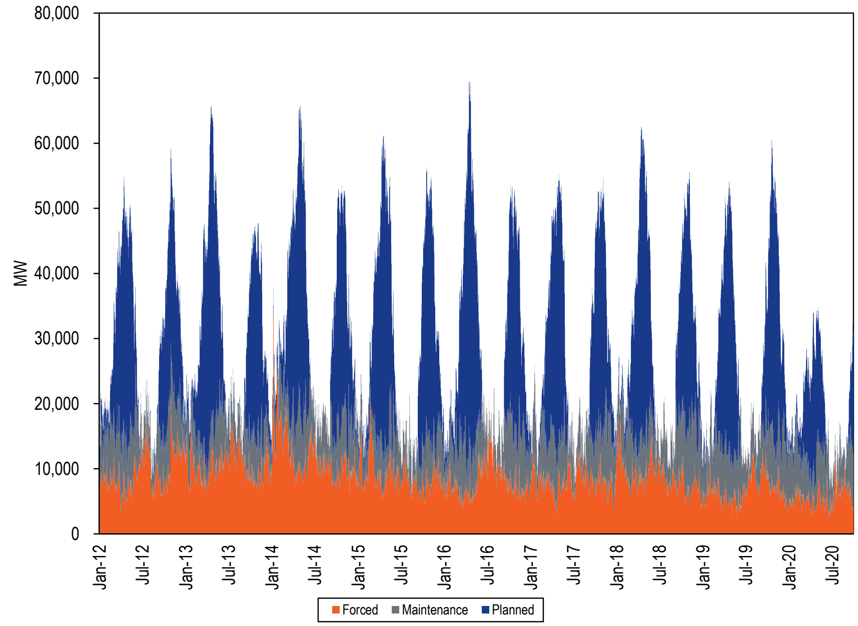
Generator Performance Factors

Generator outages fall into three categories: planned, maintenance, and forced. The MW on outage vary throughout the year. For example, the MW on planned outage are generally highest in the spring and fall, as shown in Figure 5-10, due to restrictions on planned outages during the winter and summer. The effect of the seasonal variation in outages can be seen in the monthly generator performance metrics in Figure 5-14.

130 The capacity factors in this table are based on nameplate capacity values, and are calculated based on when the units come on line.

131 The subcategories of steam units are consolidated consistent with confidentiality rules. Coal is comprised of coal and waste coal. Natural gas is comprised of natural gas and propane. Oil is comprised of both heavy and light oil. Biomass is comprised of biomass, landfill gas, and municipal solid waste.

Figure 5-10 Outages (MW): 2012 through September 2020



In the first nine months of 2020, forced and planned outages were lower than in 2018 and 2019 (Figure 5-11). The MWh of planned outages in the first nine months of 2020 were 31 percent lower than in the first nine months of 2019 and the MWh of forced outages were 4 percent lower than in the first nine months of 2019. The MWh of maintenance outages were 1 percent higher than in the first nine months of 2019.

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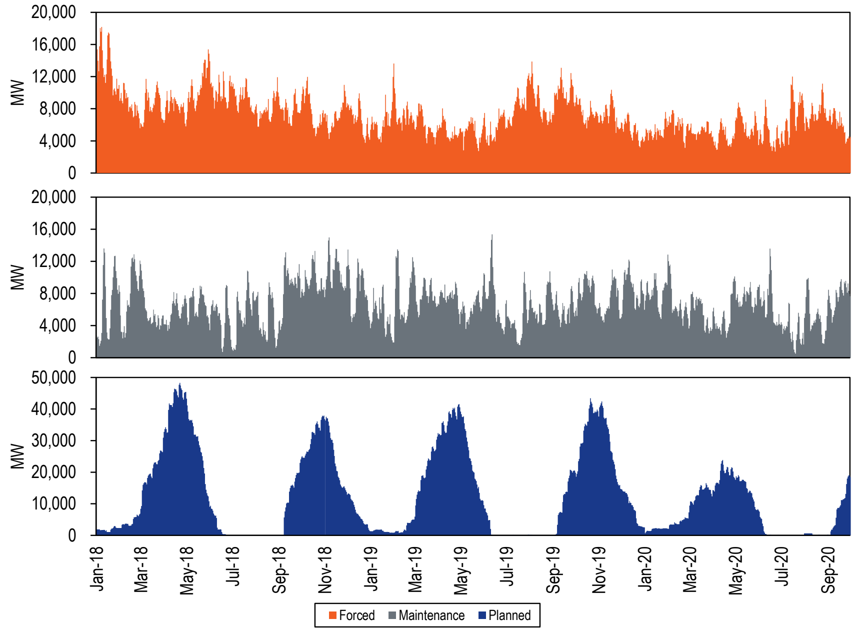
Figure 5-11 Outages (MW): Forced, maintenance and planned outages 2018 through September 2020



Performance factors include the equivalent availability factor (EAF), the equivalent maintenance outage factor (EMOF), the equivalent planned outage factor (EPOF) and the equivalent forced outage factor (EFOF). These four factors add to 100 percent for any generating unit. The EAF is the proportion of hours in a year when a unit is available to generate at full capacity while the three outage factors include all the hours when a unit is unavailable. The EMOF is the proportion of hours in a year when a unit is unavailable because of maintenance outages and maintenance deratings. The EPOF is the proportion of hours in a year when a unit is unavailable because of planned outages and planned deratings. The EFOF is the proportion of hours in a year when a unit is unavailable because of forced outages and forced deratings.

The PJM aggregate EAF, EFOF, EPOF, and EMOF are shown in Figure 5-12. Metrics by unit type are shown in Table 5-26.

Figure 5-12 Equivalent outage and availability factors: January through September, 2007 to 2020

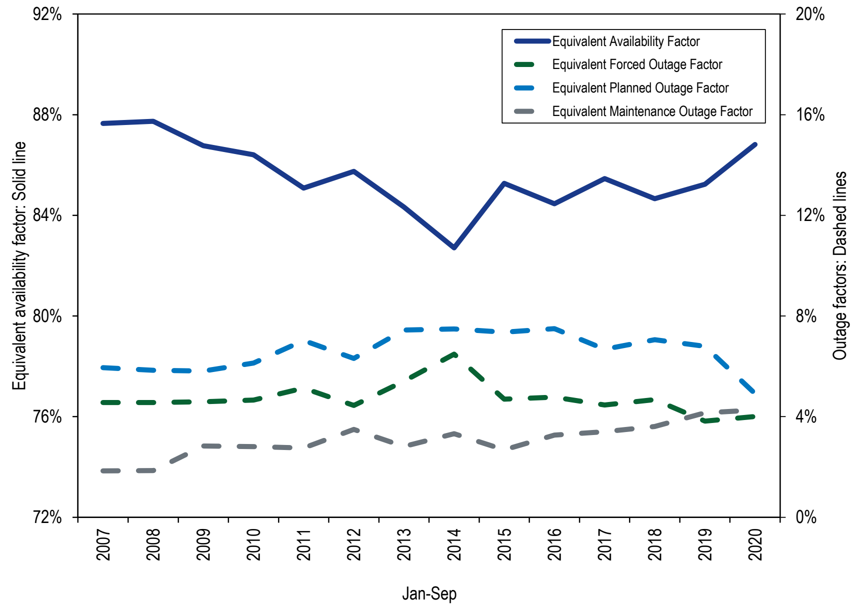


Table 5-26 EFOF, EPOF, EMOF and EAF by unit type: January through September, 2007 through 2020

	Coal				Combined Cycle				Combustion Turbine				Diesel				Hydroelectric				Nuclear				Other			
Jan-Sep	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF
2007	7.0%	8.4%	2.5%	82.2%	2.2%	5.2%	1.3%	91.2%	4.6%	2.3%	2.1%	91.0%	10.8%	0.7%	1.8%	86.7%	1.3%	5.4%	1.6%	91.8%	1.1%	3.8%	0.3%	94.7%	6.0%	7.2%	2.8%	83.9%
2008	7.9%	6.3%	2.4%	83.3%	2.1%	5.0%	1.4%	91.5%	3.0%	3.9%	1.9%	91.2%	9.8%	1.2%	1.2%	87.9%	1.6%	6.8%	1.7%	89.9%	0.9%	5.2%	0.6%	93.3%	4.2%	8.7%	2.6%	84.4%
2009	6.7%	7.1%	3.6%	82.6%	3.4%	5.1%	3.5%	88.0%	1.5%	2.7%	2.1%	93.8%	6.7%	0.3%	1.2%	91.8%	2.1%	8.9%	2.3%	86.7%	4.2%	4.2%	0.7%	90.9%	3.4%	7.9%	5.0%	83.7%
2010	7.8%	7.8%	4.2%	80.2%	2.6%	6.0%	3.1%	88.3%	2.0%	2.0%	1.6%	94.4%	4.7%	0.6%	0.8%	93.9%	0.8%	8.4%	2.1%	88.8%	1.9%	4.4%	0.5%	93.1%	5.0%	8.3%	3.5%	83.3%
2011	8.7%	8.1%	4.0%	79.3%	2.4%	7.0%	2.1%	88.5%	2.0%	3.2%	1.5%	93.2%	3.8%	0.0%	1.9%	94.3%	1.6%	13.2%	2.0%	83.2%	2.2%	5.8%	1.5%	90.5%	5.1%	8.1%	3.0%	83.8%
2012	7.3%	7.5%	5.8%	79.3%	2.5%	6.4%	1.8%	89.3%	2.0%	2.4%	1.5%	94.1%	3.9%	0.1%	1.7%	94.4%	3.5%	4.9%	1.8%	89.8%	1.4%	6.1%	0.9%	91.6%	4.8%	8.3%	4.7%	82.2%
2013	8.5%	9.4%	4.4%	77.6%	1.9%	8.5%	2.6%	87.0%	5.3%	3.1%	1.3%	90.2%	5.5%	0.3%	1.4%	92.8%	2.1%	6.5%	1.6%	89.7%	1.2%	5.6%	0.8%	92.4%	7.5%	9.2%	3.7%	79.6%
2014	10.0%	8.2%	5.2%	76.5%	2.8%	8.7%	2.1%	86.4%	7.7%	3.3%	1.4%	87.5%	14.0%	0.5%	2.3%	83.2%	2.0%	8.9%	3.0%	86.1%	1.8%	5.9%	0.9%	91.5%	7.1%	12.9%	5.9%	74.1%
2015	8.1%	7.7%	4.0%	80.1%	2.1%	8.3%	1.7%	87.9%	2.9%	4.1%	1.7%	91.3%	8.4%	0.4%	2.3%	88.9%	2.3%	7.9%	1.5%	88.3%	1.2%	4.9%	1.3%	92.7%	6.6%	15.3%	4.2%	73.9%
2016	8.7%	7.9%	5.9%	77.5%	3.0%	8.6%	1.7%	86.7%	2.2%	4.3%	1.9%	91.6%	5.4%	0.2%	2.5%	91.9%	2.1%	6.7%	2.7%	88.4%	2.1%	4.6%	1.1%	92.2%	5.2%	16.5%	3.8%	74.5%
2017	10.1%	8.1%	6.6%	75.3%	1.9%	7.9%	1.6%	88.6%	1.2%	3.9%	1.7%	93.2%	5.8%	0.2%	1.7%	92.3%	2.2%	5.3%	2.9%	89.6%	0.6%	5.0%	0.6%	93.9%	4.3%	8.5%	5.0%	82.2%
2018	10.6%	9.6%	6.8%	73.0%	1.5%	7.9%	1.2%	89.4%	2.0%	4.2%	1.5%	92.4%	6.2%	0.9%	2.7%	90.2%	2.2%	5.3%	3.1%	89.4%	0.8%	4.5%	0.5%	94.2%	4.0%	8.2%	8.1%	79.8%
2019	8.4%	7.8%	8.4%	75.3%	1.6%	7.9%	1.7%	88.8%	1.5%	5.4%	1.6%	91.5%	7.3%	1.0%	2.3%	89.3%	1.4%	5.4%	3.6%	89.7%	0.9%	4.6%	0.9%	93.5%	3.8%	9.9%	6.5%	79.7%
2020	1.6%	7.9%	1.7%	88.8%	1.5%	5.4%	1.6%	91.5%	7.3%	1.0%	2.3%	89.3%	1.4%	5.4%	3.6%	89.7%	0.9%	4.6%	0.9%	93.5%	3.8%	9.9%	6.5%	79.7%	3.8%	6.8%	4.1%	85.2%

Generator Forced Outage Rates

The most fundamental forced outage rate metric is the equivalent demand forced outage rate (EFORd). EFORd is a measure of the probability that a generating unit will fail, either partially or totally, to perform when it is needed to operate. EFORd measures the forced outage rate during periods of demand, and does not include planned or maintenance outages. A period of demand is a period during which a generator is running or needed to run. EFORd calculations use historical performance data, including equivalent forced outage hours, service hours, average forced outage duration, average run time, average time between unit starts, available hours and period hours.[132] The EFORd metric includes all forced outages, regardless of the reason for those outages.

The average PJM EFORd in the first nine months of 2020 was 6.3 percent, an increase from 6.0 percent in the first nine months of 2019. Figure 5-13 shows the average EFORd since 1999 for all units in PJM.[133]

132 Equivalent forced outage hours are the sum of all forced outage hours in which a generating unit is fully inoperable and all partial forced outage hours in which a generating unit is partially inoperable prorated to represent full hours.
133 The universe of units in PJM changed as the PJM footprint expanded and as units retired from and entered PJM markets. See the *2019 State of the Market Report for PJM*, Appendix A: "PJM Overview" for details.

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Figure 5-13 Trends in the equivalent demand forced outage rate (EFORd): 1999 through 2020

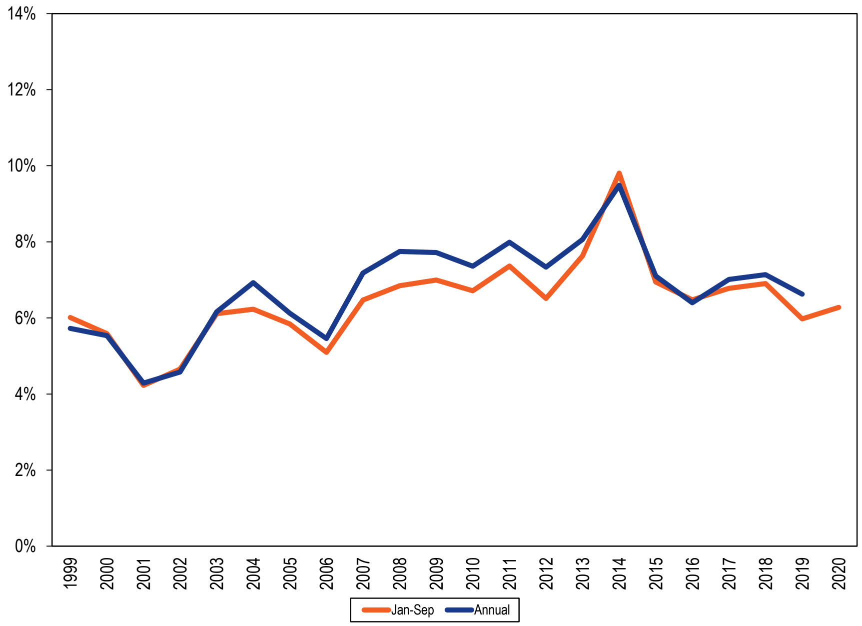

Table 5-27 shows the class average EFORd by unit type.

Table 5-27 EFORd by unit type: January through September, 2007 through 2020

	Jan-Sep													
	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Coal	7.9%	8.9%	8.2%	9.2%	10.8%	9.6%	10.8%	12.5%	9.5%	10.6%	12.7%	13.5%	11.8%	9.7%
Combined Cycle	3.7%	3.5%	4.8%	3.6%	3.1%	3.1%	2.6%	4.6%	2.8%	3.6%	2.4%	2.2%	2.0%	4.1%
Combustion Turbine	11.2%	11.3%	9.1%	9.1%	7.9%	6.5%	10.5%	17.7%	9.9%	5.3%	5.0%	6.4%	5.1%	4.1%
Diesel	12.3%	10.8%	8.8%	6.7%	9.8%	5.1%	6.1%	15.0%	9.7%	7.3%	7.1%	6.8%	8.0%	7.4%
Hydroelectric	1.9%	2.5%	2.7%	1.3%	2.2%	5.1%	3.2%	3.1%	3.1%	2.9%	3.1%	2.8%	1.7%	4.9%
Nuclear	1.2%	1.0%	4.3%	2.1%	2.4%	1.5%	1.3%	2.0%	1.2%	2.3%	0.6%	0.8%	1.0%	1.3%
Other	10.2%	9.6%	8.5%	7.9%	9.2%	8.3%	12.2%	13.6%	13.1%	9.8%	12.6%	9.5%	9.4%	16.7%
Total	6.5%	6.8%	7.0%	6.7%	7.4%	6.5%	7.6%	9.8%	6.9%	6.5%	6.8%	6.9%	6.0%	6.3%

Other Forced Outage Rate Metrics

Under the capacity performance modifications to RPM, effective with the 2018/2019 Delivery Year, neither XEFORd nor EFORp are relevant.

Forced Outage Analysis

The MMU analyzed the causes of forced outages for the entire PJM system. The metric used was lost generation, which is the product of the duration of the outage and the size of the outage reduction. Lost generation can be converted into lost system equivalent availability.[134] On a system wide basis, the resultant lost equivalent availability from the forced outages is equal to the equivalent forced outage factor (EFOF).

PJM EFOF was 4.0 percent in the first nine months of 2020. This means there was 4.0 percent lost availability because of forced outages. Table 5-28 shows that forced outages for boiler tube leaks, at 13.6 percent of the systemwide EFOF, were the largest single contributor to EFOF.

134 For any unit, lost generation can be converted to lost equivalent availability by dividing lost generation by the product of the generating units' capacity and period hours. This can also be done on a systemwide basis.

Table 5-28 Contribution to EFOF by unit type by cause: January through September, 2020

	Coal	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Other	System
Boiler Tube Leaks	23.8%	1.8%	0.0%	0.0%	0.0%	0.0%	7.0%	13.6%
Electrical	2.6%	38.3%	14.0%	5.9%	6.2%	0.0%	1.9%	8.9%
Miscellaneous (Pollution Control Equipment)	12.0%	0.0%	0.1%	0.0%	0.0%	0.0%	0.1%	6.3%
High Pressure Turbine	10.9%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	5.7%
Catastrophe	1.8%	6.9%	1.7%	0.1%	54.4%	0.0%	6.5%	5.4%
Unit Testing	2.9%	3.9%	9.2%	25.9%	16.5%	0.5%	13.1%	5.4%
Generator	0.7%	18.6%	0.3%	5.1%	1.0%	4.9%	6.5%	4.7%
Controls	2.8%	0.8%	1.2%	9.7%	2.2%	0.0%	16.4%	4.0%
Feedwater System	6.5%	1.0%	0.0%	0.0%	0.0%	4.4%	1.0%	4.0%
Boiler Air and Gas Systems	3.4%	0.0%	0.0%	0.0%	0.0%	0.0%	16.2%	3.9%
Boiler Piping System	5.7%	2.2%	0.0%	0.0%	0.0%	0.0%	0.5%	3.4%
Miscellaneous (Steam Turbine)	0.8%	1.4%	0.0%	0.0%	0.0%	0.0%	16.2%	2.8%
Miscellaneous (Gas Turbine)	0.0%	4.8%	27.1%	0.0%	0.0%	0.0%	0.0%	2.5%
Boiler Fuel Supply from Bunkers to Boiler	4.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.5%	2.3%
Steam Generators and Steam System	0.0%	0.0%	0.0%	0.0%	0.0%	30.9%	0.0%	2.2%
Wet Scrubbers	3.9%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	2.0%
Economic	3.2%	0.1%	0.2%	3.0%	4.4%	0.0%	0.4%	2.0%
Auxiliary Systems	1.0%	1.8%	6.5%	0.0%	0.1%	0.0%	0.2%	1.3%
Reactor Coolant System	0.0%	0.0%	0.0%	0.0%	0.0%	17.4%	0.0%	1.2%
All Other Causes	13.9%	18.2%	39.7%	50.4%	15.1%	41.9%	13.2%	18.4%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

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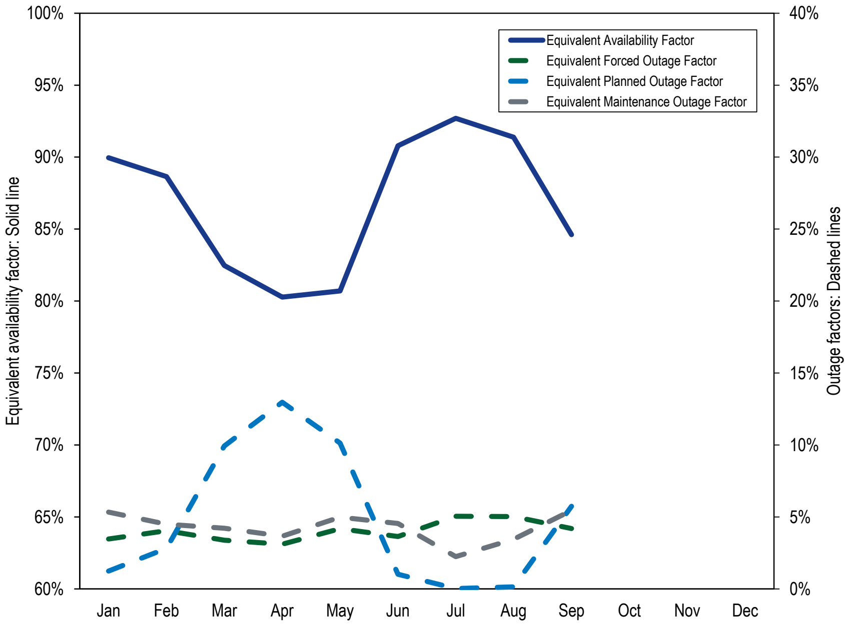
Performance by Month

On a monthly basis, unit availability as measured by the equivalent availability factor is shown in Figure 5-14.

Figure 5-14 Monthly generator performance factors: January through September, 2020



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