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. 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 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 non-performance 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. 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.

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. Base Residual Auctions (BRA) are held for Delivery Years that are three years in the future. Effective with the 2012/2013 Delivery Year, First, Second and Third Incremental Auctions (IA) are held for each Delivery Year.[5] Prior to the 2012/2013 Delivery Year, the Second Incremental Auction was conducted if PJM determined that an unforced capacity resource shortage exceeded 100 MW of unforced capacity due to a load forecast increase. Effective January 31, 2010, First, Second, and Third Incremental Auctions are conducted 20, 10, and three months prior to the Delivery Year.[6] Also effective for the 2012/2013 Delivery Year, 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.[7]

The 2019/2020 RPM Third Incremental Auction was conducted in the first three months of 2019.

On June 9, 2015, FERC accepted changes to the PJM capacity market rules proposed in PJM's Capacity Performance (CP) filing.[8] For a transition period during the 2018/2019 and 2019/2020 Delivery Years, PJM will procure two product types, Capacity Performance and Base Capacity. PJM also procured Capacity Performance resources in two transition auctions for the 2016/2017 and 2017/2018 Delivery Years. Effective with the 2020/2021 Delivery Year, PJM will procure a single capacity product, Capacity Performance. CP Resources are expected to be available and capable of providing energy and reserves when needed at any time during the Delivery Year.[9] Effective for the 2018/2019 through the 2019/2020 Delivery Years, a Base Capacity Demand Resource Constraint and a Base Capacity Resource Constraint are established for each modeled LDA. These maximum quantities are set for reliability purpose to limit the quantity procured of the less available products, including Base Capacity Generation Resources, Base Capacity Demand Resources, and Base Capacity Energy Efficiency Resources. The Capacity Performance (CP) Transition Incremental Auctions (IAs) were held as part of a five year transition to a single capacity product type in the 2020/2021 Delivery Year. Participation in the CP Transition IAs was voluntary. If a resource cleared a CP Transition IA and had a prior commitment for the relevant delivery year, the existing commitment was converted to a CP commitment, which is subject to the CP performance requirements and nonperformance charges. The Transition IAs were not designed to minimize the cost of purchasing Capacity Performance resources for the two delivery years and were not designed to maximize economic welfare for the two delivery years.

RPM prices are locational and may vary depending on transmission constraints.[10] 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

4 The terms *PJM Region*, *RTO Region* and *RTO* are synonymous in this report and include all capacity within the PJM footprint.
5 See 126 FERC ¶ 61,275 at P 86 (2009).
6 See Letter Order, FERC Docket No. ER10-366-000 (January 22, 2010).
7 See 126 FERC ¶ 61,275 at P 88 (2009).
8 See 151 FERC ¶ 61,208 (2015).
9 See "PJM Manual 18: PJM Capacity Market," Rev. 41 (Jan. 1, 2019) § 1.5, at p 19.
10 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.

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.** During the first three months of 2019, RPM installed capacity decreased 910.9 MW or 0.5 percent, from 186,496.1 MW on January 1 to 185,585.2 MW on March 31. 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 March 31, 2018, 41.0 percent was gas; 31.8 percent was coal; 17.6 percent was nuclear; 4.8 percent was hydroelectric; 3.4 percent was oil; 0.6 percent was wind; 0.4 percent was solid waste; and 0.3 percent was solar.
- **Market Concentration.** In the 2019/2020 RPM Third Incremental Auction all participants in the total PJM market as well as the LDA RPM markets failed the three pivotal supplier (TPS) test.[11] 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.[12] [13] [14]
- **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 10,798.7 MW for June 1, 2018, as a result of cleared capacity for demand resources and energy efficiency resources in RPM auctions for the 2018/2019 Delivery Year (13,731.7 MW) less replacement capacity (2,933.0 MW).

Market Conduct

- **2019/2020 RPM Third Incremental Auction.** Of the 137 generation resources that submitted Base Capacity offers, the MMU calculated offer caps for one generation resource (0.7 percent), of which one (0.7 percent) was a unit-specific offer cap. Of the 454 generation resources that submitted Capacity Performance offers, the MMU calculated unit specific offer caps for four generation resources (0.9 percent).

Market Performance

- The 2019/2020 RPM Third Incremental Auction was conducted in the first three months of 2019. The weighted average capacity price for the 2018/2019 Delivery Year is $172.09, including all RPM auctions for the 2018/2019 Delivery Year held 2018. The weighted average capacity price for the 2019/2020 Delivery Year is $112.63, including all RPM auctions for the 2019/2020 Delivery Year held through 2018.
- For the 2018/2019 Delivery Year, RPM annual charges to load are $11.0 billion.
- In the 2021/2022 RPM Base Residual Auction, 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.

11 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).

12 See OATT Attachment DD § 6.5.

13 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).

14 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).

Generator Performance

- **Forced Outage Rates.** The average PJM EFORd for the first three months of 2019 was 7.0 percent, a decrease from 9.0 percent for the first three months of 2018.[15]
- **Generator Performance Factors.** The PJM aggregate equivalent availability factor for the first three months of 2019 was 86.2 percent, an increase from 85.7 percent for the first three months of 2018.
- **Outages Deemed Outside Management Control (OMC).** In the first three months of 2019, 3.1 percent of forced outages were classified as OMC outages.

Recommendations[16]

The MMU recognizes that PJM has implemented the Capacity Performance Construct to replace some of the existing core market rules and to address fundamental performance incentive issues. The MMU recognizes that the Capacity Performance Construct addresses many of the MMU's recommendations. The MMU's recommendations are based on the existing capacity market rules. The status is reported as adopted if the recommendation was included in FERC's order approving PJM's Capacity Performance filing.[17]

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 types, including planned generation, demand resources and imports.[18 19] (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.[20 21] 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.)

15 The generator performance analysis includes all PJM capacity resources for which there are data in the PJM generator availability data systems (GADS) database. This set of capacity resources may include generators in addition to those in the set of generators committed as capacity resources in RPM. Data was downloaded from the PJM GADS database on April 30, 2019. 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.

17 151 FERC ¶ 61,208 (2015).

18 See also Comments of the Independent Market Monitor for PJM, Docket No. ER14-503-000 (December 20, 2013).

19 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).

20 See PJM Interconnection, L.L.C., Docket No. ER12-513-000 (December 1, 2011) ("Triennial Review").

21 See the *2017 State of the Market Report for PJM*, Volume 2, Section 7: Net Revenue.

- 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. New recommendation. Status: Not adopted.)

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.[22] (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.[23] (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

22 Brief of the Independent Market Monitor for PJM, Docket No. EL16-49, ER18-1314-000,-001; EL18-178 (October 2, 2018).

23 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).

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 Q3, 2018. Status: Not adopted.)

Performance Incentive Requirements of RPM

- The MMU recommends that a unit which is not capable of supplying energy consistent with its day-ahead offer 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 PAH 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.)

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 non-performance 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.

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 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 three months of 2019. 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 2017 and 2018, the MMU prepared a number of RPM related reports and testimony, shown in Table 5-2. The capacity performance modifications to the RPM construct have significantly improved the capacity market and addressed many of the issues identified by the MMU. The MMU will continue to publish more detailed reports on the CP auctions which include more specific issues and suggestions for improvements.

The PJM markets have worked to provide incentives to entry and to retaining capacity. PJM had excess reserves of more than 9,000 ICAP MW on June 1, 2018, and will have excess reserves of more than 13,000 ICAP MW on June 1, 2019, based on current positions.[30] Capacity investments in PJM were financed by market sources. Of the 30,881.7 MW of additional capacity that cleared in RPM auctions for the 2007/2008 through 2017/2018 delivery years, 22,419.7 MW (72.6 percent) were based on market funding. Of the 13,718.4 MW of additional capacity that cleared in RPM auctions for the 2018/2019 through 2021/2022 delivery years, 11,772.7 MW (85.8 percent) are 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, emerged more fully in 2017 and 2018 and the first three months of 2019. The subsidies are not part of the PJM market design but nonetheless threaten the

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, 2016," <http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Analysis_of_Replacement_Capacity_for_RPM_Commitments_06012007_to_06012016_20161227.pdf> (December 27, 2016).

29 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).

30 The calculated reserve margin for June 1, 2019, does not account for cleared buy bids that have not been used in replacement capacity transactions.

foundations of the PJM Capacity Market as well as the competitiveness of PJM markets overall.

The Ohio subsidy proceedings, the Illinois ZEC legislation to subsidize the Quad Cities nuclear power plant, the request in Pennsylvania to subsidize the Three Mile Island and other 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, and the request by FirstEnergy to the U.S. DOE for subsidies consistent with the DOE Grid Resilience Proposal, 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 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).

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 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.

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.

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. 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 to help ensure reliability.

As a result of the fact that demand side resources have contributed to price suppression in PJM capacity markets, the place of demand side in PJM should be reexamined. 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.

Table 5-2 RPM related MMU reports: 2018 through March 2019

Date	Name
January 19, 2018	Analysis of Replacement Capacity for RPM Commitments http://www.monitoringanalytics.com/reports/Presentations/2018/IMM_IASTF_Analysis_of_Replacement_Capacity_for_RPM_Commitments_20180119.pdf
January 25, 2018	MOPR-Ex Main Motion http://www.monitoringanalytics.com/reports/Presentations/2018/IMM_MRC_MOPR-Ex_Main_Motion_20180125.pdf
January 25, 2018	MOPR-Ex Alternate Proposal http://www.monitoringanalytics.com/reports/Presentations/2018/IMM_MRC_MOPR-Ex_Alternate_Proposal_20180125.pdf
January 25, 2018	MOPR-Ex Memo http://www.monitoringanalytics.com/reports/Presentations/2018/IMM_MRC_MOPR-Ex_Memo_20180125.pdf
February 23, 2018	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2018/2019, 2019/2020 and 2020/2021 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Notice_RPM_Must_Offer_Obligations_20180223.pdf
March 9, 2018	Generation Additions and Retirements in the PJM Capacity Market: MW and Funding Sources http://www.monitoringanalytics.com/reports/Reports/2018/IMM_Generation_Additions_and_Retirements_in_the_PJM_Capacity_Market_20180309.pdf
April 11, 2018	IMM Comments re Base Capacity Complaint Docket Nos. EL17-32 and EL17-36 http://www.monitoringanalytics.com/reports/Reports/2018/IMM_Comments_Docket_No_EL17-32_EL17-36_20180411.pdf
May 9, 2018	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/IMM_Notice_RPM_Must_Offer_Obligations_20180509.pdf
June 1, 2018	IMM CONE CT Study Results http://www.monitoringanalytics.com/reports/Presentations/2018/IMM_MIC_Quadrennial_Review_Special_Session_CONE_CT_Study_Results_20180601.pdf
June 7, 2018	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/IMM_Notice_RPM_Must_Offer_Obligations_20180706.pdf
June 13, 2018	IMM Post Technical Conf. Comments re Base Capacity Complaint Docket No. EL17-31, -36 http://www.monitoringanalytics.com/Filings/2018/IMM_Post_Tech_Conf_Comments_Docket_No_EL17-32_-36_20180713.pdf
June 22, 2018	IMM CONE CT Study Results http://www.monitoringanalytics.com/reports/Presentations/2018/IMM_MIC_Quadrennial_Review_Special_Session_CONE_CT_Study_Results_20180601.pdf
August 24, 2018	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	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2019/2020, 2020/2021 and 2021/2022 Delivery Years (PDF) http://www.monitoringanalytics.com/reports/Market_Messages/Messages/IMM_Notice_RPM_Must_Offer_Obligations_20180824.pdf
September 26, 2018	MOPR/FRR Sensitivity Analyses of the 2021/2022 RPM Base Residual Auction http://www.monitoringanalytics.com/reports/Reports/2018/IMM_MOPR_FRR_Sensitivity_Analyses_Report_20180926.pdf
October 2, 2018	IMM Brief re Capacity Market Investigation Docket Nos. EL16-49-000,ER18-1314-000,-001, EL18-178 http://www.monitoringanalytics.com/Filings/2018/IMM_Brief_Docket_No_EL16-49_EL18-178_ER18-1314_20181002.pdf
October 22, 2018	IMM Comments re NJ ZECs Docket No. EO18080899 http://www.monitoringanalytics.com/Filings/2018/IMM_Comments_Docket_No_EO18080899_20181022.pdf
October 23, 2018	IMM Notice of Withdrawal re Fairless MOPR Docket No. EL17-82 http://www.monitoringanalytics.com/Filings/2018/IMM_Notice_of_Withdrawal_Docket_No_EL17-82_20181023.pdf
October 31, 2018	IMM Summary of Position re Capacity Market Investigation Docket Nos. EL18-178, ER18-1314-000,-001, EL16-49 http://www.monitoringanalytics.com/Filings/2018/IMM_Summary_of_Position_Docket_No__EL18-178_ER18-1314_EL16-49.pdf
November 6, 2018	IMM Brief re Capacity Market Investigation Docket Nos. EL18-178, ER18-1314-000,-001, EL16-49 http://www.monitoringanalytics.com/Filings/2018/IMM_Reply_Brief_Docket_No_EL18-178_ER18-1314-000_001_EL16-49_20181106.pdf
November 19, 2018	IMM Protest re Quadrennial Review Docket No. ER19-105 http://www.monitoringanalytics.com/Filings/2018/IMM_Protest_Docket_No_ER19-105_20181119.pdf
November 19, 2018	IMM Protest re Maintenance Adders Docket No. ER19-210 http://www.monitoringanalytics.com/Filings/2018/IMM_Protest_Docket_No_ER19-210_20181119.pdf
December 21, 2018	IMM Answer and Motion for Leave to Answer re VOM Complaint and Maintenance Adder Docket No. EL19-8, ER19-210 http://www.monitoringanalytics.com/Filings/2018/IMM_Answer_Docket_Nos_EL19-8_ER19-210_20181221.pdf
December 31, 2018	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_20181231.pdf
February 21, 2019	IMM Complaint re CONE x B Offers Docket No. EL19-xxx 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

Installed Capacity

On January 1, 2019, RPM installed capacity was 186,496.1 MW (Table 5-3).[31] Over the next three months, new generation, unit deactivations, facility reratings, plus import and export shifts resulted in RPM installed capacity of 185,585.2 MW on March 31, 2019, a decrease of 910.9 MW or 0.5 percent from the January 1 level.[32 33] The 910.9 MW decrease was the result of deactivations (1,692.0 MW) and derates (66.4 MW), offset by new or reactivated generation (824.7 MW) and uprates (22.8 MW).

At the beginning of the new delivery year on June 1, 2018, RPM installed capacity was 183,386.2 MW, a decrease of 1,658.3 MW or 0.9 percent from the May 31, 2018 level.

Table 5-3 Installed capacity (By fuel source): January 1, January 31, February 28, and March 31, 2019

	01-Jan-19		31-Jan-19		28-Feb-19		31-Mar-19	
	MW	Percent	MW	Percent	MW	Percent	MW	Percent
Coal	60,763.4	32.6%	60,763.4	32.6%	59,092.6	32.0%	59,092.6	31.8%
Gas	75,261.2	40.4%	75,276.9	40.4%	75,265.1	40.7%	76,089.8	41.0%
Hydroelectric	8,888.2	4.8%	8,888.2	4.8%	8,873.9	4.8%	8,873.9	4.8%
Nuclear	32,684.5	17.5%	32,684.5	17.5%	32,677.8	17.7%	32,677.8	17.6%
Oil	6,388.2	3.4%	6,388.2	3.4%	6,359.5	3.4%	6,340.5	3.4%
Solar	640.0	0.3%	640.0	0.3%	640.0	0.3%	640.0	0.3%
Solid waste	712.3	0.4%	712.3	0.4%	712.3	0.4%	712.3	0.4%
Wind	1,158.3	0.6%	1,158.3	0.6%	1,158.3	0.6%	1,158.3	0.6%
Total	186,496.1	100.0%	186,511.8	100.0%	184,779.5	100.0%	185,585.2	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, 2018, as well as the expected installed capacity for the next three delivery years, based on the results of all auctions held through March 31, 2019.[34] On June 1, 2007, coal comprised 40.7 percent of the installed capacity, reached a maximum of 42.9 percent in 2012, decreased to 33.3 percent on June 1, 2018 and is projected to decrease to 28.2 percent by June 1, 2021. The share of gas increased from 29.1 percent in 2007 to 38.9 percent in 2018 and is projected to increase to 50.3 percent in 2021.

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

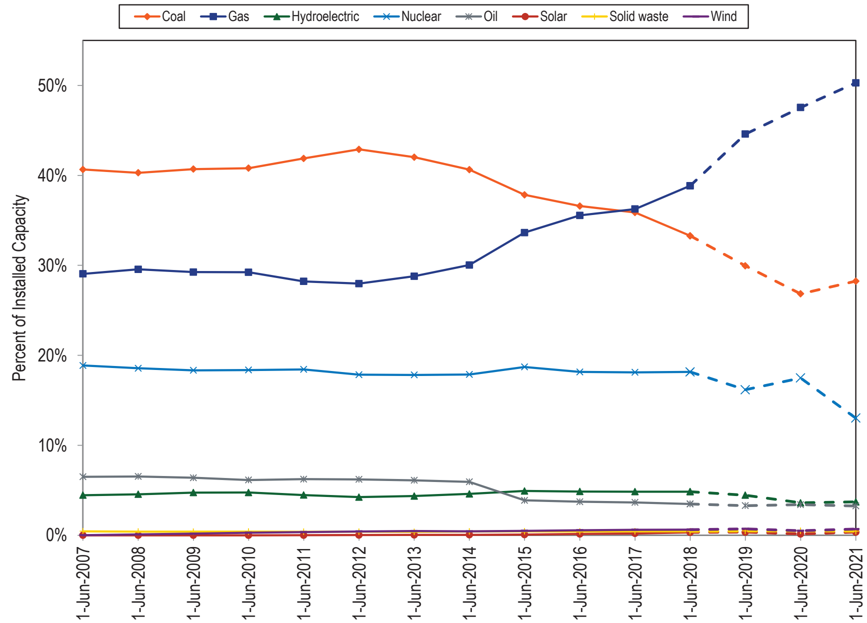


Table 5-4 shows the RPM installed capacity on January 1, 2019, through March 31, 2019, for the top five generation capacity resource owners, excluding FRR committed MW.

31 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.

32 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 eRPM system, regardless of whether the capacity cleared in the RPM auctions.

33 Wind resources accounted for 1,158.3 MW, and solar resources accounted for 640.0 MW of installed capacity in PJM on March 31, 2019. 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," Rev. 12 (Jan. 1, 2017) § B.3, at p 18.

34 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.

Table 5-4 Installed capacity by parent company: January 1, January 31, February 28, and March 31, 2019

	01-Jan-19			31-Jan-19			28-Feb-19			31-Mar-19		
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	22,819.1	13.3%	1	22,819.1	13.3%	1	22,814.9	13.4%	1	22,795.9	13.3%	1
Dominion Resources, Inc.	20,388.9	11.8%	2	20,388.9	11.8%	2	20,372.4	12.0%	2	20,372.4	11.9%	2
FirstEnergy Corp.	14,644.0	8.5%	3	14,644.0	8.5%	3	12,980.5	7.6%	3	12,980.5	7.6%	3
Vistra Energy Corp.	12,082.3	7.0%	4	12,082.3	7.0%	4	12,082.0	7.1%	4	12,082.0	7.1%	4
Talen Energy Corporation	10,959.3	6.4%	5	10,975.0	6.4%	5	10,964.0	6.4%	5	10,964.0	6.4%	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, 2019, to March 31, 2019, by funding type.

Table 5-5 Installed capacity by funding type: January 1, January 31, February 28, and March 31, 2018

	01-Jan-19		31-Jan-19		28-Feb-19		31-Mar-19	
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	153,676.9	82.4%	153,692.6	82.4%	151,987.2	82.3%	152,792.9	82.3%
Nonmarket	32,819.2	17.6%	32,819.2	17.6%	32,792.3	17.7%	32,792.3	17.7%
Total	186,496.1	100.0%	186,511.8	100.0%	184,779.5	100.0%	185,585.2	100.0%

Fuel Diversity

Figure 5-2 shows the fuel diversity index (FDI_c) for RPM installed capacity.[35] 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.[36] 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.[37] The average FDI_c for the first three months of 2019 decreased 0.7 percent from the first three months of 2018. 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.

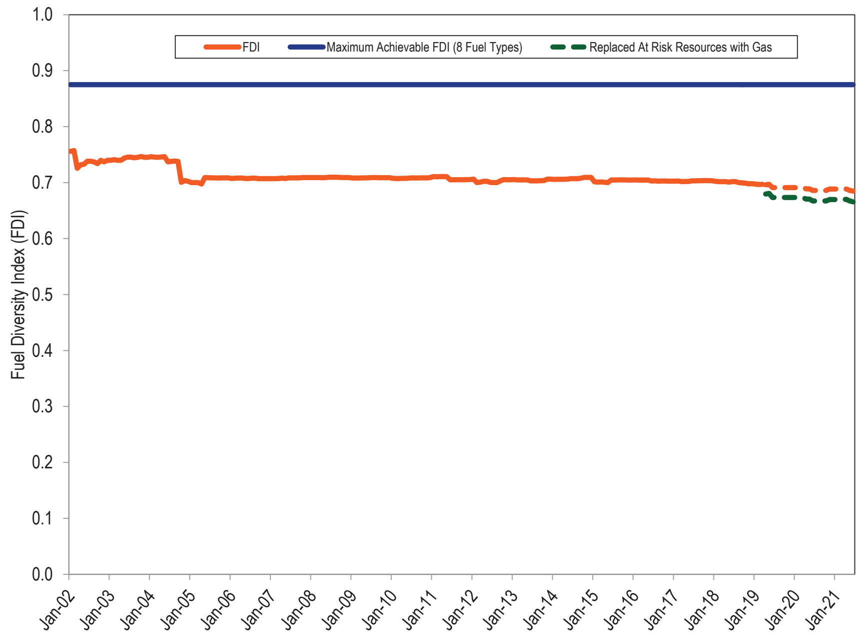
The FDI_c was used to measure the impact of potential retirements of resources that the MMU has identified as being at risk of retirement. There were 18 capacity resources with installed capacity totaling 14,954 MW identified as being at risk of retirement. The dashed green line in Figure 5-2 shows the FDI_c calculated assuming that the capacity from these 18 resources that has cleared in a RPM auction is replaced by gas generation. The FDI_c under these assumptions would decrease by 0.018 (2.6 percent) on average from the expected FDI_c for the period April 1, 2019, through June 1, 2021.

35 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.

36 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.

37 See the *2018 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.

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



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.[38]

In the first three months of 2019, the 2019/2020 RPM Third Incremental Auction was conducted.

Market Structure

Supply

Table 5-6 shows generation capacity changes since the implementation of the Reliability Pricing Model through the 2017/2018 Delivery Year. The 19,726.8 MW increase was the result of new generation capacity resources (23,479.1 MW), reactivated generation capacity resources (971.0 MW), uprates (6,431.6 MW), integration of external zones (18,109.0 MW), a net increase in capacity imports (3,545.5 MW), a net decrease in capacity exports (2,519.2 MW), offset by deactivations (31,959.6 MW) and derates (3,369.0 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 final peak load forecast for the given 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 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, 2019, and June 1, 2020, do not account for cleared buy bids that have not been used in replacement capacity transactions. The projected reserve margins for June 1, 2019, and June 1, 2020, account for projected replacement capacity using cleared buy bids by applying the rate at which historical buy bids have been used.

38 See *PJM Interconnection, L.L.C.*, Letter Order in Docket No. ER10-366-000 (January 22, 2010).

Future Changes in Generation Capacity[39]

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 2017/2018 Delivery Year, internal installed capacity decreased by 4,446.9 MW after accounting for new capacity resources, reactivations, and uprates (30,881.7 MW) and capacity deactivations and derates (35,328.6 MW).

For the current and future delivery years (2018/2019 through 2021/2022), new generation capacity is defined as capacity that cleared an RPM auction for the first time in the specified DY. Looking ahead, based on expected completion rates of cleared new generation capacity (10,654.1 MW) and pending deactivations (10,950.2 MW), PJM capacity is expected to decrease by 296.1 MW for the 2018/2019 through 2021/2022 Delivery Years.

Table 5-6 Generation capacity changes: 2007/2008 to 2018/2019

	ICAP (MW)									
	Total at June 1	New	Reactivations	Uprates	Integration	Net Change in Capacity Imports	Net Change in Capacity Exports	Deactivations	Derates	Net Change
2007/2008	163,659.4	372.8	156.8	1,238.1	0.0	(96.7)	143.9	389.5	617.8	519.8
2008/2009	164,179.2	812.9	6.3	1,108.9	0.0	871.1	(1,702.9)	615.0	612.4	3,274.7
2009/2010	167,453.9	188.1	13.0	370.4	0.0	68.6	735.9	472.4	171.2	(739.4)
2010/2011	166,714.5	1,751.2	16.0	587.3	11,821.6	187.2	(427.0)	1,439.2	286.9	13,064.2
2011/2012	179,778.7	3,095.0	138.0	553.8	3,607.4	262.7	(1,374.5)	2,758.5	313.0	5,959.9
2012/2013	185,738.6	266.4	79.0	364.5	2,680.0	841.8	(17.3)	4,152.1	267.6	(170.7)
2013/2014	185,567.9	264.7	20.9	397.9	0.0	2,217.2	21.6	4,027.7	421.9	(1,570.5)
2014/2015	183,997.4	3,036.0	0.0	480.4	0.0	859.1	73.3	11,442.9	221.0	(7,361.7)
2015/2016	176,635.7	5,497.8	0.0	409.0	0.0	787.6	285.1	863.4	156.4	5,389.5
2016/2017	182,025.2	2,537.8	537.0	589.8	0.0	(1,011.1)	(36.4)	1,447.3	167.8	1,074.8
2017/2018	183,100.0	5,656.4	4.0	331.5	0.0	(1,442.0)	(220.9)	4,351.6	133.0	286.2
2018/2019	183,386.2									
Total		23,479.1	971.0	6,431.6	18,109.0	3,545.5	(2,519.2)	31,959.6	3,369.0	19,726.8

Sources of Funding[40]

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 generation capacity from the 2007/2008 DY through the 2017/2018 DY totaled 23,479.1 MW (76.0 percent of all additions), with 16,450.0 MW from market funding and 7,029.1 MW from nonmarket funding. Reactivated generation capacity from the 2007/2008 DY through the 2017/2018 DY totaled 971.0 MW (3.1 percent of all additions), with 896.0 MW from market funding and 75.0 MW from nonmarket funding. Uprates to existing generation capacity from the 2007/2008 DY through the 2017/2018 DY totaled 6,431.6 MW (20.8 percent of all additions), with 5,073.7 MW from market funding and 1,357.9 MW from nonmarket funding. In summary, of the 30,881.7 MW of additional capacity from new, reactivated, and uprated generation that cleared in RPM auctions for the 2007/2008 through 2017/2018 delivery years, 22,419.7 MW (72.6 percent) were based on market funding.

Of the 5,512.7 MW of the additional generation capacity (new resources, reactivated resources, and uprates) that cleared in RPM auctions for the 2018/2019 through 2021/2022 delivery years, that are not yet in service, 5,477.7 MW have market funding and 35.0 MW have nonmarket funding. Applying the historical completion rates, 3,959.8 MW, or 72.3 percent, of the market funded projects are expected to go into service. Similarly, 22.0 MW, or 62.8 percent, of nonmarket funded projects are expected to go into service. Together, 3,981.8 MW, or 72.2 percent, of new generation capacity that cleared

39 For more details on future changes in generation capacity, see "Generation Additions and Retirements in the PJM Capacity Market: MW and Funding Sources for Delivery Years 2007/2008 through 2020/2021," <http://www.monitoringanalytics.com/reports/Reports/2018/IMM_Generation_Additions_and_Retirements_in_the_PJM_Capacity_Market_20180309.pdf> (March 9, 2018).

40 For more details on sources of funding for generation capacity, see "Generation Additions and Retirements in the PJM Capacity Market: MW and Funding Sources for Delivery Years 2007/2008 through 2020/2021," <http://www.monitoringanalytics.com/reports/Reports/2018/IMM_Generation_Additions_and_Retirements_in_the_PJM_Capacity_Market_20180309.pdf> (March 9, 2018).

MW in RPM and are not yet in service are expected to go into service through the 2021/2022 Delivery Year.

Of the 8,205.7 MW of the additional generation capacity that cleared in RPM auctions for the 2018/2019 through 2021/2022 delivery years and are already in service, 6,295.0 MW (76.7 percent) are based on market funding. In summary, 11,772.7 MW (85.8 percent) of the additional generation capacity (6,295.0 MW in service and 5,477.7 MW not yet in service) that cleared in RPM auctions for the 2018/2019 through 2021/2022 delivery years are based on market funding. Capacity additions based on nonmarket funding are 1,945.7 MW (14.2 percent) of proposed generation that cleared at least one RPM auction for the 2018/2019 through 2021/2022 delivery years.

- **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.

Table 5-7 RPM reserve margin: June 1, 2016, to June 1, 2021[41] [42]

	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 Percent	Reserve Margin in Excess of IRM ICAP (MW)	Projected Replacement Capacity using Cleared Buy Bids UCAP (MW)	Projected Reserve Margin
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	164,777.8	151,643.5	12,284.2	0.0	139,359.3	16.0%	6.08%	175,444.8	25.9%	9.9%	13,788.1	1,616.1	24.7%
01-Jun-20	165,943.4	152,245.4	12,065.2	558.0	139,622.2	15.9%	5.97%	176,479.2	26.4%	10.5%	14,657.1	3,446.6	23.8%
01-Jun-21	160,795.3	152,647.4	12,107.1	510.0	140,030.3	15.8%	5.89%	170,858.9	22.0%	6.2%	8,703.8	0.0	22.0%

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.
- **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, 2018 PJM EDCs and their affiliates maintained a large market share of load obligations under RPM, together totaling 59.8 percent (Table 5-8), down from 63.6 percent on June 1, 2017. The combined market share of LSEs not affiliated with any EDC and of non-PJM EDC affiliates was 40.2 percent, up from 36.4 percent on June 1, 2017. The share of capacity market load obligation fulfilled by PJM EDCs and their affiliates, and LSEs not affiliated

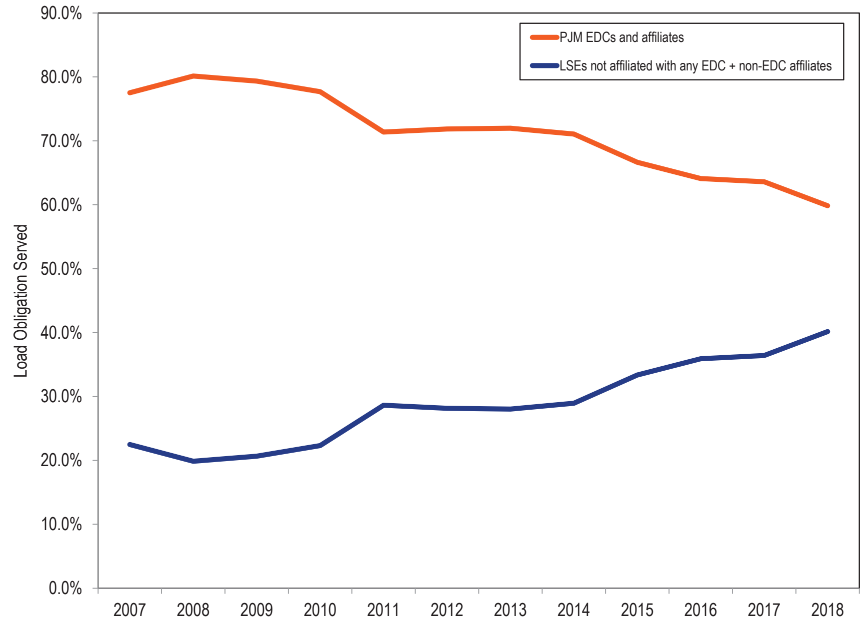
41 The calculated reserve margins in this table do not include EE on the supply side or the EE add back on the demand side. The EE excluded from the supply side for this calculation includes annual EE and summer EE. This is how PJM calculates the reserve margin.
42 These reserve margin calculations do not consider Fixed Resource Requirement (FRR) load.

with any EDC and non-PJM EDC affiliates from June 1, 2007 to June 1, 2018 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 59.8 percent on June 1, 2018. 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 40.2 percent on June 1, 2018. 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.

Table 5-8 Capacity market load obligation served: June 1, 2018

	Obligation (MW)		
	PJM EDCs and Affiliates	LSEs not affiliated with any EDC + non EDC Affiliates	Total
Obligation	106,696.8	71,617.7	178,314.4
Percent of total obligation	59.8%	40.2%	100.0%

Figure 5-3 Capacity market load obligation served: June 1, 2007 through June 1, 2018



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 for 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. The MW of CTRs available for allocation to LSEs in an LDA is 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 $6,734,907, 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 $7,605,806. BGE had 306.0 MW of ICTRs due to Incremental Rights-Eligible Required Transmission Enhancements with a value of $8,180,931.

Market Concentration

Auction Market Structure

As shown in Table 5-9, in the 2019/2020 RPM Third Incremental Auction all participants in the total PJM market as well as the LDA RPM markets failed the three pivotal supplier (TPS).[43] 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.[44] [45] [46]

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.

43 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.

44 See OATT Attachment DD § 6.5.

45 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).

46 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).

Table 5-9 RSI results: 2018/2019 through 2021/2022 RPM Auctions[47]

RPM Markets	$RSI_{1,\ 1.05}$	RSI_3	Total Participants	Failed RSI_3 Participants
2018/2019 Base Residual Auction				
RTO	0.81	0.65	125	125
EMAAC	0.59	0.16	12	12
ComEd	1.11	0.02	4	4
2018/2019 First Incremental Auction				
RTO	0.51	0.23	32	32
EMAAC	-0.00	0.00	2	2
ComEd	0.00	0.00	1	1
2018/2019 Second Incremental Auction				
RTO	0.64	0.87	44	9
EMAAC	0.25	0.06	5	5
2018/2019 Third Incremental Auction				
RTO	0.88	0.65	71	71
EMAAC	0.00	0.00	3	3
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
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
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

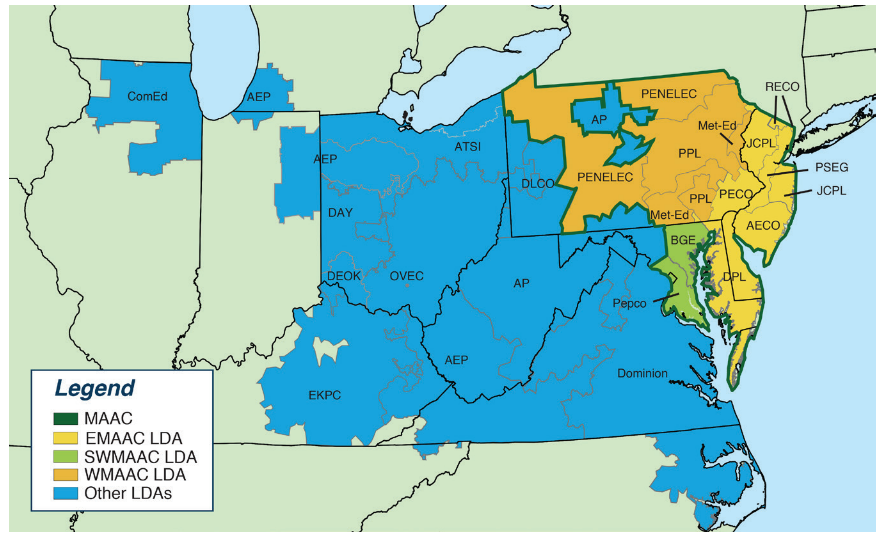
47 The RSI shown is the lowest RSI in the market.

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.[48]

Locational Deliverability Areas are shown in Figure 5-4, Figure 5-5 and Figure 5-6.

Figure 5-4 Map of locational deliverability areas



48 For definitions of the RPM Locational Deliverability Areas see *2018 State of the Market Report for PJM*, Section 5 Capacity Market, at Locational Deliverability Areas (LDAs). <http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2018/2018-som-pjm-sec5.pdf>

Figure 5-5 Map of RPM EMAAC subzonal LDAs

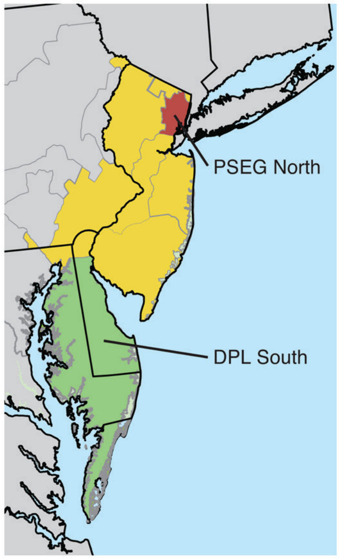
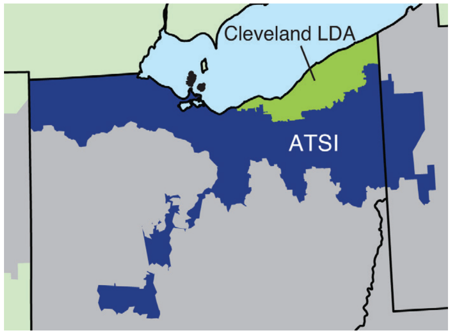


Figure 5-6 Map of RPM ATSI subzonal LDA



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.[49 50]

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

49 For an explanation of importing and exporting capacity see *2018 State of the Market Report for PJM*, Section 5 Capacity Market, at Imports and Exports. <http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2018/2018-som-pjm-sec5.pdf>
50 OATT Attachment DD § 5.6.6(b).

Demand Resources

There are two basic demand products incorporated in the RPM market design.[51]

As shown in Table 5-11, Table 5-12, and Table 5-13, capacity in the RPM load management programs was 10,798.7 MW for June 1, 2018, as a result of cleared capacity for demand resources and energy efficiency resources in RPM auctions for the 2018/2019 Delivery Year (13,731.7 MW) less replacement capacity (2,933.0 MW).

Table 5-11 RPM load management statistics by LDA: June 1, 2017 to June 1, 2021[52 53 54 55]

		UCAP (MW)														
		RTO	MAAC	EMAAC	SWMAAC	DPL South	PSEG	PSEG North	Pepco	ATSI	ATSI Cleveland	ComEd	BGE	PPL	DAY	DEOK
01-Jun-17	DR cleared	11,870.7	4,584.5	1,630.9	1,464.1	86.3	402.8	157.1	658.3	1,256.0	323.5	1,602.9	805.8	811.9		
	EE cleared	1,922.3	547.7	180.0	291.5	5.6	55.2	18.5	155.4	192.3	41.4	747.6	136.1	43.2		
	DR net replacements	(3,870.8)	(1,461.6)	(555.7)	(344.8)	(39.5)	(107.9)	(30.6)	(136.5)	(457.2)	(163.1)	(279.2)	(208.3)	(299.2)		
	EE net replacements	195.6	145.8	20.6	98.3	(0.4)	4.4	2.6	26.2	(41.9)	(11.7)	10.3	72.1	(9.9)		
	Total RPM load management	10,117.8	3,816.4	1,275.8	1,509.1	52.0	354.5	147.6	703.4	949.2	190.1	2,081.6	805.7	546.0		
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	(3,181.8)	(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		
	Total RPM load management	10,798.7	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	(245.9)	(50.9)	(19.9)	(2.2)	(0.4)	(6.1)	(3.6)	(1.2)	(2.9)		(81.4)		(17.6)		
	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		
	Total RPM load management	12,985.7	4,649.4	2,034.6	1,116.5	98.7	509.6	225.7	723.4	1,248.9	374.6	2,471.4	393.1	796.5		
01-Jun-20	DR cleared	9,008.7	2,823.2	1,168.9	481.1	72.6	339.0	152.7	234.6	853.0	227.1	1,623.0	246.5	615.6	211.4	164.1
	EE cleared	2,080.5	683.7	346.7	261.4	8.7	119.6	38.7	114.2	172.0	40.1	722.6	147.2	44.2	53.8	74.1
	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
	Total RPM load management	11,089.2	3,506.9	1,515.6	742.5	81.3	458.6	191.4	348.8	1,025.0	267.2	2,345.6	393.7	659.8	265.2	238.2
01-Jun-21	DR cleared	11,125.8	3,413.4	1,378.9	624.9	66.3	407.9	188.6	345.9	1,142.4	272.8	1,997.8	279.0	684.7	227.7	213.8
	EE cleared	2,832.0	938.7	617.0	207.0	13.6	240.1	72.9	102.6	148.2	36.2	770.5	104.4	72.4	60.1	89.7
	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
	Total RPM load management	13,957.8	4,352.1	1,995.9	831.9	79.9	648.0	261.5	448.5	1,290.6	309.0	2,768.3	383.4	757.1	287.8	303.5

51 For an explanation of demand resources and energy efficiency products in the capacity market, see *2018 State of the Market Report for PJM*, Section 5, Capacity Market, at Demand Resources. <http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2018/2018-som-pjm-sec5.pdf>

52 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.

53 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 replacement transactions reported for the 2014/2015 Delivery Year include transactions associated with RTP Controls, Inc., which was declared in collateral default on March 9, 2012.

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

55 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[56 57 58]

	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	(3,181.8)	8,253.6		8,252.6	8,512.0	1.091	9,282.4
01-Jun-19	10,703.1	0.0	(245.9)	10,457.2	0.0	10,457.2	0.0	1.090	0.0
01-Jun-20	9,008.7	0.0	0.0	9,008.7	0.0	9,008.7	0.0	1.090	0.0
01-Jun-21	11,125.8	0.0	0.0	11,125.8	0.0	11,125.8	0.0	1.090	0.0

Table 5-13 RPM commitments and replacements for energy efficiency resources: June 1, 2007 to June 1, 2021[59 60]

	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	0.0	2,528.5	0.0	2,528.5
01-Jun-20	2,080.5	0.0	0.0	2,080.5	0.0	2,080.5
01-Jun-21	2,832.0	0.0	0.0	2,832.0	0.0	2,832.0

56 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.

57 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.

58 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.

59 Pursuant to PJM Operating Agreement § 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 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.

60 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.

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.[61]

2019/2020 RPM Third Incremental Auction

As shown in Table 5-14, 137 generation resources submitted Base Capacity offers in the 2019/2020 RPM Third Incremental Auction. The MMU calculated offer caps for one generation resource (0.7 percent), of which zero were based on the technology specific default (proxy) ACR values and one was a unit-specific offer cap (0.7 percent of all generation resources), of which all included an APIR component. Of the 137 generation resources with Base Capacity offers, 112 generation resources elected the offer cap option of 1.1 times the BRA clearing price (81.8 percent), two Planned Generation Capacity Resources had uncapped offers (1.5 percent), and the remaining 22 generation resources were price takers (16.1 percent). Market power mitigation was applied to the Base Capacity sell offers of zero generation resources, including 0.0 MW.

As shown in Table 5-14, 454 generation resources submitted Capacity Performance offers in the 2019/2020 RPM Third Incremental Auction. The MMU calculated offer caps for four generation resources (0.9 percent), all of which were unit-specific with an APIR component. Of the 454 generation resources, 394 generation resources had the net CONE times B offer cap (86.8 percent), 37 generation resources elected the offer cap option of 1.1 times the BRA clearing price (8.1 percent), one Planned Generation Capacity Resource had an uncapped offer (0.2 percent), and the remaining 18 generation resources were price takers (4.0 percent). Market power mitigation was applied to the Capacity Performance sell offers of zero generation resources, including 0.0 MW.

61 For an explanation of offer caps, offer floors, and the minimum offer price rule (MOPR), see *2018 State of the Market Report for PJM*, Section 5 Capacity Market, at Offer Caps and Offer Floors. <http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2018/2018-som-pjm-sec5.pdf>

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 210.2 ICAP MW of MOPR Unit-Specific Exception requests for the 2019/2020 RPM Third Incremental Auction, requests for 210.2 MW were granted.

Table 5-14 ACR statistics: 2019/2020 RPM Auctions

	2019/2020 Base Residual Auction				2019/2020 First Incremental Auction				2019/2020 Second Incremental Auction				2019/2020 Third Incremental Auction			
	Base Capacity		Capacity Performance		Base Capacity		Capacity Performance		Base Capacity		Capacity Performance		Base Capacity		Capacity Performance	
Offer Cap/Mitigation Type	Number of Generation Resources	Percent of Generation Resources Offered	Number of Generation Resources	Percent of Generation Resources Offered	Number of Generation Resources	Percent of Generation Resources Offered	Number of Generation Resources	Percent of Generation Resources Offered	Number of Generation Resources	Percent of Generation Resources Offered	Number of Generation Resources	Percent of Generation Resources Offered	Number of Generation Resources	Percent of Generation Resources Offered	Number of Generation Resources	Percent of Generation Resources Offered
Default ACR	171	33.9%	0	0.0%	17	21.0%	1	0.3%	10	13.9%	NA	NA	0	0.0%	NA	NA
Unit specific ACR (APIR)	34	6.7%	8	0.8%	11	13.6%	5	1.3%	8	11.1%	5	1.2%	1	0.7%	4	0.9%
Unit specific ACR (APIR and CPQR)	0	0	17	1.7%	0	0	1	0.3%	0	0	1	0.2%	0	0	0	0.0%
Unit specific ACR (non-APIR)	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Unit specific ACR (non-APIR and CPQR)	0	0	0	0.0%	0	0	0	0.0%	0	0	0	0.0%	0	0	0	0.0%
Opportunity cost input	7	1.4%	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Default ACR and opportunity cost	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%	NA	NA	0	0.0%	0	0.0%
Net CONE times B	NA	NA	888	88.5%	NA	NA	362	94.8%	NA	NA	350	85.6%	NA	NA	394	86.8%
Offer cap of 1.1 times BRA clearing price elected	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	112	81.8%	37	8.1%
Uncapped planned uprate and default ACR	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%	NA	NA	0	0.0%	NA	NA
Uncapped planned uprate and opportunity cost	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Uncapped planned uprate and Net CONE times B	NA	NA	2	0.2%	NA	NA	0	0.0%	NA	NA	3	0.7%	NA	NA	0	0.0%
Uncapped planned uprate and price taker	0	0.0%	0	0.0%	0	0.0%	1	0.3%	1	1.4%	1	0.2%	0	0.0%	0	0.0%
Uncapped planned uprate and 1.1 times BRA clearing price elected	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	0	0.0%	0	0.0%
Uncapped planned generation resources	9	1.8%	14	1.4%	0	0.0%	1	0.3%	2	2.8%	0	0.0%	2	1.5%	1	0.2%
Existing generation resources as price takers	284	56.2%	74	7.4%	53	65.4%	11	2.9%	51	70.8%	49	12.0%	22	16.1%	18	4.0%
Total Generation Capacity Resources offered	505	100.0%	1,003	100.0%	81	100.0%	382	100.0%	72	100.0%	409	100.0%	137	100.0%	454	100.0%

Table 5-15 MOPR statistics: RPM Auctions conducted in first quarter, 2019[62]

		Number of Requests	ICAP (MW)			UCAP (MW)	
		(Company-Plant Level)	Requested	Granted	Offered	Offered	Cleared
2019/2020 Third Incremental Auction	Competitive Entry Exemption	8	210.2	210.2	5.4	5.3	5.3
	Self-Supply Exemption	0	0.0	0.0	0.0	0.0	0.0
	Unit-Specific Exception for resources	0	0.0	0.0	0.0	0.0	0.0
	Unit-Specific Exception for uprates	0	0.0	0.0	0.0	0.0	0.0
	Other MOPR Screened Generation Resources	0	0.0	0.0	46.2	44.8	0.0
	Total	8	210.2	210.2	51.6	50.1	5.3

62 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 not reported as a result of PJM confidentiality rules.

Replacement Capacity[63]

Table 5-16 shows the committed and replacement capacity for all capacity resources for June 1 of each year from 2007 through 2021. The 2019 through 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	(9,757.9)	167,306.3	0.0	167,306.3
01-Jun-20	168,634.0	0.0	(610.1)	168,023.9	0.0	168,023.9
01-Jun-21	163,627.3	0.0	0.0	163,627.3	0.0	163,627.3

Market Performance

Figure 5-7 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 three months of 2019, and Table 5-18 shows the RPM cleared MW for all RPM auctions held through the first three months of 2019.

Figure 5-8 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 three months of 2019. A summary of these weighted average prices is given in Table 5-19.

Table 5-20 shows RPM revenue by resource type for all RPM auctions held through the first three months of 2019 with $9.4 billion for new/repower/reactivated generation resources based on the unforced MW cleared and the resource clearing prices. A resource classified as "new/repower/reactivated" is a capacity resource addition since the implementation of RPM and is considered "new/repower/reactivated" for its initial offer and all its subsequent offers in RPM auctions.

63 For more details on replacement capacity, 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).

Table 5-21 shows RPM revenue by calendar year for all RPM auctions held through the first three months of 2019. In 2017, RPM revenue was $8.8 billion. In 2018, RPM revenue was $10.3 billion.

Table 5-22 shows the RPM annual charges to load. For the 2017/2018 Delivery Year, RPM annual charges to load are $9.1 billion. For the 2018/2019 Delivery Year, annual charges to load are $11.0 billion.

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
2007/2008 BRA		$40.80	$40.80	$40.80	$40.80	$197.67	$188.54	$197.67	$197.67	$197.67	$188.54		$40.80	$188.54
2008/2009 BRA		$111.92	$111.92	$111.92	$111.92	$148.80	$210.11	$148.80	$148.80	$148.80	$210.11		$111.92	$210.11
2008/2009 Third Incremental Auction		$10.00	$10.00	$10.00	$10.00	$10.00	$223.85	$10.00	$10.00	$10.00	$223.85		$10.00	$223.85
2009/2010 BRA		$102.04	$191.32	$191.32	$191.32	$191.32	$237.33	$191.32	$191.32	$191.32	$237.33		$102.04	$237.33
2009/2010 Third Incremental Auction		$40.00	$86.00	$86.00	$86.00	$86.00	$86.00	$86.00	$86.00	$86.00	$86.00		$40.00	$86.00
2010/2011 BRA		$174.29	$174.29	$174.29	$174.29	$174.29	$174.29	$186.12	$174.29	$174.29	$174.29		$174.29	$174.29
2010/2011 Third Incremental Auction		$50.00	$50.00	$50.00	$50.00	$50.00	$50.00	$50.00	$50.00	$50.00	$50.00		$50.00	$50.00
2011/2012 BRA		$110.00	$110.00	$110.00	$110.00	$110.00	$110.00	$110.00	$110.00	$110.00	$110.00		$110.00	$110.00
2011/2012 First Incremental Auction		$55.00	$55.00	$55.00	$55.00	$55.00	$55.00	$55.00	$55.00	$55.00	$55.00		$55.00	$55.00
2011/2012 ATSI FRR Integration Auction		$108.89	$108.89	$108.89	$108.89	$108.89	$108.89	$108.89	$108.89	$108.89	$108.89	$108.89	$108.89	$108.89
2011/2012 Third Incremental Auction		$5.00	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00
2012/2013 BRA		$16.46	$133.37	$16.46	$133.37	$139.73	$133.37	$222.30	$139.73	$185.00	$133.37		$16.46	$133.37
2012/2013 ATSI FRR Integration Auction		$20.46	$20.46	$20.46	$20.46	$20.46	$20.46	$20.46	$20.46	$20.46	$20.46	$20.46	$20.46	$20.46
2012/2013 First Incremental Auction		$16.46	$16.46	$16.46	$16.46	$153.67	$16.46	$153.67	$153.67	$153.67	$16.46	$16.46	$16.46	$16.46
2012/2013 Second Incremental Auction		$13.01	$13.01	$13.01	$13.01	$48.91	$13.01	$48.91	$48.91	$48.91	$13.01	$13.01	$13.01	$13.01
2012/2013 Third Incremental Auction		$2.51	$2.51	$2.51	$2.51	$2.51	$2.51	$2.51	$2.51	$2.51	$2.51	$2.51	$2.51	$2.51
2013/2014 BRA		$27.73	$226.15	$27.73	$226.15	$245.00	$226.15	$245.00	$245.00	$245.00	$247.14	$27.73	$27.73	$226.15
2013/2014 First Incremental Auction		$20.00	$20.00	$20.00	$20.00	$178.85	$54.82	$178.85	$178.85	$178.85	$54.82	$20.00	$20.00	$54.82
2013/2014 Second Incremental Auction		$7.01	$10.00	$7.01	$10.00	$40.00	$10.00	$40.00	$40.00	$40.00	$10.00	$7.01	$7.01	$10.00
2013/2014 Third Incremental Auction		$4.05	$30.00	$4.05	$30.00	$188.44	$30.00	$188.44	$188.44	$188.44	$30.00	$4.05	$4.05	$30.00
2014/2015 BRA	Limited	$125.47	$125.47	$125.47	$125.47	$125.47	$125.47	$125.47	$125.47	$213.97	$125.47	$125.47	$125.47	$125.47
2014/2015 BRA	Extended Summer	$125.99	$136.50	$125.99	$136.50	$136.50	$136.50	$136.50	$136.50	$225.00	$136.50	$125.99	$125.99	$136.50
2014/2015 BRA	Annual	$125.99	$136.50	$125.99	$136.50	$136.50	$136.50	$136.50	$136.50	$225.00	$136.50	$125.99	$125.99	$136.50
2014/2015 First Incremental Auction	Limited	$0.03	$5.23	$0.03	$5.23	$5.23	$5.23	$5.23	$5.23	$399.62	$5.23	$0.03	$0.03	$5.23
2014/2015 First Incremental Auction	Extended Summer	$5.54	$16.56	$5.54	$16.56	$16.56	$16.56	$16.56	$16.56	$410.95	$16.56	$5.54	$5.54	$16.56
2014/2015 First Incremental Auction	Annual	$5.54	$16.56	$5.54	$16.56	$16.56	$16.56	$16.56	$16.56	$410.95	$16.56	$5.54	$5.54	$16.56
2014/2015 Second Incremental Auction	Limited	$25.00	$56.94	$25.00	$56.94	$56.94	$56.94	$56.94	$56.94	$310.00	$56.94	$25.00	$25.00	$56.94
2014/2015 Second Incremental Auction	Extended Summer	$25.00	$56.94	$25.00	$56.94	$56.94	$56.94	$56.94	$56.94	$310.00	$56.94	$25.00	$25.00	$56.94
2014/2015 Second Incremental Auction	Annual	$25.00	$56.94	$25.00	$56.94	$56.94	$56.94	$56.94	$56.94	$310.00	$56.94	$25.00	$25.00	$56.94
2014/2015 Third Incremental Auction	Limited	$25.51	$132.20	$25.51	$132.20	$132.20	$132.20	$132.20	$132.20	$256.76	$132.20	$25.51	$25.51	$132.20
2014/2015 Third Incremental Auction	Extended Summer	$25.51	$132.20	$25.51	$132.20	$132.20	$132.20	$132.20	$132.20	$256.76	$132.20	$25.51	$25.51	$132.20
2014/2015 Third Incremental Auction	Annual	$25.51	$132.20	$25.51	$132.20	$132.20	$132.20	$132.20	$132.20	$256.76	$132.20	$25.51	$25.51	$132.20
2015/2016 BRA	Limited	$118.54	$150.00	$118.54	$150.00	$150.00	$150.00	$150.00	$150.00	$150.00	$150.00	$304.62	$118.54	$150.00
2015/2016 BRA	Extended Summer	$136.00	$167.46	$136.00	$167.46	$167.46	$167.46	$167.46	$167.46	$167.46	$167.46	$322.08	$136.00	$167.46
2015/2016 BRA	Annual	$136.00	$167.46	$136.00	$167.46	$167.46	$167.46	$167.46	$167.46	$167.46	$167.46	$357.00	$136.00	$167.46
2015/2016 First Incremental Auction	Limited	$43.00	$111.00	$43.00	$111.00	$111.00	$111.00	$111.00	$122.95	$122.95	$111.00	$168.37	$43.00	$111.00

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

		RPM Clearing Price ($ per MW-day)												
	Product Type	RTO	MAAC	APS	PPL	EMAAC	SWMAAC	DPL South	PSEG	PSEG North	Pepco	ATSI	ComEd	BGE
2015/2016 First Incremental Auction	Extended Summer	$43.00	$111.00	$43.00	$111.00	$111.00	$111.00	$111.00	$122.95	$122.95	$111.00	$168.37	$43.00	$111.00
2015/2016 First Incremental Auction	Annual	$43.00	$111.00	$43.00	$111.00	$111.00	$111.00	$111.00	$122.95	$122.95	$111.00	$168.37	$43.00	$111.00
2015/2016 Second Incremental Auction	Limited	$123.56	$141.12	$123.56	$141.12	$141.12	$141.12	$141.12	$155.02	$155.02	$141.12	$204.10	$123.56	$141.12
2015/2016 Second Incremental Auction	Extended Summer	$136.00	$153.56	$136.00	$153.56	$153.56	$153.56	$153.56	$167.46	$167.46	$153.56	$216.54	$136.00	$153.56
2015/2016 Second Incremental Auction	Annual	$136.00	$153.56	$136.00	$153.56	$153.56	$153.56	$153.56	$167.46	$167.46	$153.56	$216.54	$136.00	$153.56
2015/2016 Third Incremental Auction	Limited	$100.76	$122.33	$100.76	$122.33	$122.33	$122.33	$122.33	$122.56	$122.56	$122.33	$100.76	$100.76	$122.33
2015/2016 Third Incremental Auction	Extended Summer	$163.20	$184.77	$163.20	$184.77	$184.77	$184.77	$184.77	$185.00	$185.00	$184.77	$163.20	$163.20	$184.77
2015/2016 Third Incremental Auction	Annual	$163.20	$184.77	$163.20	$184.77	$184.77	$184.77	$184.77	$185.00	$185.00	$184.77	$163.20	$163.20	$184.77
2016/2017 BRA	Limited	$59.37	$119.13	$59.37	$119.13	$119.13	$119.13	$119.13	$219.00	$219.00	$119.13	$94.45	$59.37	$119.13
2016/2017 BRA	Extended Summer	$59.37	$119.13	$59.37	$119.13	$119.13	$119.13	$119.13	$219.00	$219.00	$119.13	$114.23	$59.37	$119.13
2016/2017 BRA	Annual	$59.37	$119.13	$59.37	$119.13	$119.13	$119.13	$119.13	$219.00	$219.00	$119.13	$114.23	$59.37	$119.13
2016/2017 First Incremental Auction	Limited	$53.93	$89.35	$53.93	$89.35	$89.35	$89.35	$89.35	$214.44	$214.44	$89.35	$94.45	$53.93	$89.35
2016/2017 First Incremental Auction	Extended Summer	$60.00	$119.13	$60.00	$119.13	$119.13	$119.13	$119.13	$244.22	$244.22	$119.13	$100.52	$60.00	$119.13
2016/2017 First Incremental Auction	Annual	$60.00	$119.13	$60.00	$119.13	$119.13	$119.13	$119.13	$244.22	$244.22	$119.13	$100.52	$60.00	$119.13
2016/2017 Second Incremental Auction	Limited	$31.00	$71.00	$31.00	$71.00	$71.00	$71.00	$71.00	$99.01	$212.53	$71.00	$101.50	$31.00	$71.00
2016/2017 Second Incremental Auction	Extended Summer	$31.00	$71.00	$31.00	$71.00	$71.00	$71.00	$71.00	$99.01	$212.53	$71.00	$101.50	$31.00	$71.00
2016/2017 Second Incremental Auction	Annual	$31.00	$71.00	$31.00	$71.00	$71.00	$71.00	$71.00	$99.01	$212.53	$71.00	$101.50	$31.00	$71.00
2016/2017 Capacity Performance Transition Auction	Capacity Performance	$134.00	$134.00	$134.00	$134.00	$134.00	$134.00	$134.00	$134.00	$134.00	$134.00	$134.00	$134.00	$134.00
2016/2017 Third Incremental Auction	Limited	$5.02	$10.02	$5.02	$10.02	$10.02	$10.02	$10.02	$54.76	$184.97	$10.02	$5.02	$5.02	$10.02
2016/2017 Third Incremental Auction	Extended Summer	$5.02	$10.02	$5.02	$10.02	$10.02	$10.02	$10.02	$54.76	$184.97	$10.02	$5.02	$5.02	$10.02
2016/2017 Third Incremental Auction	Annual	$5.02	$10.02	$5.02	$10.02	$10.02	$10.02	$10.02	$54.76	$184.97	$10.02	$5.02	$5.02	$10.02
2017/2018 BRA	Limited	$106.02	$106.02	$106.02	$40.00	$106.02	$106.02	$106.02	$201.02	$201.02	$106.02	$106.02	$106.02	$106.02
2017/2018 BRA	Extended Summer	$120.00	$120.00	$120.00	$53.98	$120.00	$120.00	$120.00	$215.00	$215.00	$120.00	$120.00	$120.00	$120.00
2017/2018 BRA	Annual	$120.00	$120.00	$120.00	$120.00	$120.00	$120.00	$120.00	$215.00	$215.00	$120.00	$120.00	$120.00	$120.00
2017/2018 Capacity Performance Transition Auction	Capacity Performance	$151.50	$151.50	$151.50	$151.50	$151.50	$151.50	$151.50	$151.50	$151.50	$151.50	$151.50	$151.50	$151.50
2017/2018 First Incremental Auction	Limited	$84.00	$84.00	$84.00	$84.00	$84.00	$84.00	$84.00	$143.08	$143.08	$84.00	$84.00	$84.00	$84.00
2017/2018 First Incremental Auction	Extended Summer	$84.00	$84.00	$84.00	$84.00	$84.00	$84.00	$84.00	$143.08	$143.08	$84.00	$84.00	$84.00	$84.00
2017/2018 First Incremental Auction	Annual	$84.00	$84.00	$84.00	$84.00	$84.00	$84.00	$84.00	$143.08	$143.08	$84.00	$84.00	$84.00	$84.00
2017/2018 Second Incremental Auction	Limited	$26.50	$26.50	$26.50	$26.50	$26.50	$26.50	$26.50	$120.43	$179.00	$26.50	$26.50	$26.50	$26.50
2017/2018 Second Incremental Auction	Extended Summer	$26.50	$26.50	$26.50	$26.50	$26.50	$26.50	$26.50	$120.43	$179.00	$26.50	$26.50	$26.50	$26.50
2017/2018 Second Incremental Auction	Annual	$26.50	$26.50	$26.50	$26.50	$26.50	$26.50	$26.50	$120.43	$179.00	$26.50	$26.50	$26.50	$26.50
2017/2018 Third Incremental Auction	Limited	$36.49	$36.49	$36.49	$36.49	$36.49	$36.49	$36.49	$115.76	$115.76	$36.49	$36.49	$36.49	$36.49
2017/2018 Third Incremental Auction	Extended Summer	$36.49	$36.49	$36.49	$36.49	$36.49	$36.49	$36.49	$115.76	$115.76	$36.49	$36.49	$36.49	$36.49
2017/2018 Third Incremental Auction	Annual	$36.49	$36.49	$36.49	$36.49	$36.49	$36.49	$36.49	$115.76	$115.76	$36.49	$36.49	$36.49	$36.49
2018/2019 BRA	Base Capacity	$149.98	$149.98	$149.98	$75.00	$210.63	$149.98	$210.63	$210.63	$210.63	$149.98	$149.98	$200.21	$149.98
2018/2019 BRA	Base Capacity DR/EE	$149.98	$149.98	$149.98	$75.00	$210.63	$59.95	$210.63	$210.63	$210.63	$41.09	$149.98	$200.21	$59.95
2018/2019 BRA	Capacity Performance	$164.77	$164.77	$164.77	$164.77	$225.42	$164.77	$225.42	$225.42	$225.42	$164.77	$164.77	$215.00	$164.77
2018/2019 First Incremental Auction	Base Capacity	$22.51	$22.51	$22.51	$22.51	$80.04	$22.51	$35.68	$80.04	$80.04	$22.51	$22.51	$25.36	$22.51
2018/2019 First Incremental Auction	Base Capacity DR/EE	$22.51	$22.51	$22.51	$22.51	$80.04	$22.51	$35.68	$80.04	$80.04	$22.51	$22.51	$25.36	$22.51
2018/2019 First Incremental Auction	Capacity Performance	$27.15	$27.15	$27.15	$27.15	$84.68	$27.15	$84.68	$84.68	$84.68	$27.15	$27.15	$30.00	$27.15
2018/2019 Second Incremental Auction	Base Capacity	$5.00	$5.00	$5.00	$5.00	$35.02	$5.00	$30.00	$35.02	$35.02	$5.00	$5.00	$5.00	$5.00
2018/2019 Second Incremental Auction	Base Capacity DR/EE	$5.00	$5.00	$5.00	$5.00	$35.02	$5.00	$30.00	$35.02	$35.02	$5.00	$5.00	$5.00	$5.00
2018/2019 Second Incremental Auction	Capacity Performance	$50.00	$50.00	$50.00	$50.00	$80.02	$50.00	$80.02	$80.02	$80.02	$50.00	$50.00	$50.00	$50.00
2018/2019 Third Incremental Auction	Base Capacity	$14.29	$14.29	$14.29	$14.29	$19.30	$14.29	$5.00	$19.30	$19.30	$14.29	$14.29	$14.29	$3.50

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

		RPM Clearing Price ($ per MW-day)												
	Product Type	RTO	MAAC	APS	PPL	EMAAC	SWMAAC	DPL South	PSEG	PSEG North	Pepco	ATSI	ComEd	BGE
2018/2019 Third Incremental Auction	Base Capacity DR/EE	$14.29	$14.29	$14.29	$14.29	$19.30	$14.29	$5.00	$19.30	$19.30	$14.29	$14.29	$14.29	$3.50
2018/2019 Third Incremental Auction	Capacity Performance	$34.99	$34.99	$34.99	$34.99	$34.99	$34.99	$34.99	$34.99	$34.99	$34.99	$34.99	$34.99	$34.99
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
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

Table 5-18 Capacity market cleared MW: 2007/2008 through 2021/2022 RPM Auctions[64]

		UCAP (MW)															
Delivery Year	Auction	Rest of RTO	Rest of MAAC	APS	EMAAC	SWMAAC	DPL South	PSEG	PSEG North	Pepco	ATSI	ATSI Cleveland	ComEd	BGE	PPL	DAY	DEOK
2007/2008	BASE	88,410.2	-	-	30,797.8	10,201.2	-	-	-	-	-	-	-	-	-	-	-
2008/2009	BASE	88,745.1	-	-	30,231.3	10,621.2	-	-	-	-	-	-	-	-	-	-	-
2008/2009	THIRD	719.5	-	-	292.1	20.6	-	-	-	-	-	-	-	-	-	-	-
2009/2010	BASE	59,684.1	-	30,982.5	31,650.6	9,914.6	-	-	-	-	-	-	-	-	-	-	-
2009/2010	THIRD	503.1	-	178.7	353.8	762.8	-	-	-	-	-	-	-	-	-	-	-
2010/2011	BASE	68,777.4	51,019.9	-	-	10,873.4	1,519.7	-	-	-	-	-	-	-	-	-	-
2010/2011	THIRD	1,313.1	373.6	-	-	127.9	31.2	-	-	-	-	-	-	-	-	-	-
2011/2012	BASE	132,264.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2011/2012	FIRST	361.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2011/2012	THIRD	1,557.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2012/2013	BASE	70,679.4	22,777.6	-	22,644.7	11,643.5	1,354.1	3,672.1	3,582.5	-	-	-	-	-	-	-	-
2012/2013	FIRST	452.2	16.1	-	560.4	38.7	167.8	319.9	133.6	-	-	-	-	-	-	-	-
2012/2013	SECOND	539.1	143.8	-	102.9	4.0	0.1	24.3	23.6	-	-	-	-	-	-	-	-
2012/2013	THIRD	1,871.9	215.0	-	170.2	16.4	56.3	37.5	36.2	-	-	-	-	-	-	-	-
2013/2014	BASE	85,103.4	23,562.4	-	23,203.9	6,450.4	1,612.4	3,859.7	4,173.4	4,791.7	-	-	-	-	-	-	-
2013/2014	FIRST	1,719.5	128.5	-	167.8	2.0	1.3	238.7	124.2	5.1	-	-	-	-	-	-	-
2013/2014	SECOND	1,143.7	109.6	-	125.9	24.4	61.7	34.1	17.3	480.0	-	-	-	-	-	-	-
2013/2014	THIRD	1,449.0	404.1	-	301.2	1.8	9.7	1.1	4.7	531.8	-	-	-	-	-	-	-
2014/2015	BASE	82,798.7	23,497.9	-	23,527.6	5,509.5	1,551.8	3,765.5	3,812.3	5,614.6	-	-	-	-	-	-	-
2014/2015	FIRST	2,590.2	605.5	-	69.0	764.5	10.3	31.8	143.3	24.5	-	-	-	-	-	-	-
2014/2015	SECOND	2,000.4	215.1	-	271.7	159.6	13.7	5.0	0.9	243.1	-	-	-	-	-	-	-
2014/2015	THIRD	2,517.4	247.9	-	645.7	142.1	61.8	65.4	282.1	15.4	-	-	-	-	-	-	-
2015/2016	BASE	87,870.2	21,713.1	-	24,567.7	4,857.1	1,722.1	3,076.8	3,632.4	6,129.5	10,669.1	-	-	-	-	-	-
2015/2016	FIRST	1,523.6	855.2	-	92.8	654.8	.	23.9	268.3	1.7	777.4	-	-	-	-	-	-
2015/2016	SECOND	865.3	70.7	-	48.5	430.6	2.3	3.6	6.6	5.3	346.8	-	-	-	-	-	-
2015/2016	THIRD	1,908.0	464.1	-	71.2	340.9	12.5	29.5	70.1	5.6	402.1	-	-	-	-	-	-
2016/2017	BASE	22,136.2	17,491.2	-	15,181.3	4,988.1	1,577.0	2,587.9	3,693.7	5,786.3	4,155.0	2,752.8	-	-	-	-	-
2016/2017	CP TRANSITION	74,359.3	6,219.4	-	8,373.9	1,039.0	170.8	1.6	1.4	308.0	4,526.0	97.2	-	-	-	-	-
2016/2017	FIRST	1,032.3	304.2	-	417.0	132.9	0.5	409.0	7.5	8.7	295.3	2.1	-	-	-	-	-
2016/2017	SECOND	126.9	4.0	-	30.5	32.9	0.0	10.7	6.7	0.0	16.4	.	-	-	-	-	-
2016/2017	THIRD	790.1	180.6	-	264.0	22.7	11.4	22.8	84.6	71.9	11.2	6.0	-	-	-	-	-
2017/2018	BASE	19,385.3	5,132.3	-	10,218.5	733.6	792.9	2,217.5	3,893.2	2,938.8	2,896.8	911.7	8,616.1	2,488.8	4,411.9	-	-
2017/2018	CP TRANSITION	48,074.6	10,128.4	-	14,993.6	1,670.7	891.0	2.1	1.7	3,165.9	5,898.3	1,636.9	18,116.2	1,391.5	6,223.6	-	-
2017/2018	FIRST	173.6	8.8	-	31.1	.	7.0	151.4	3.1	31.6	10.1	0.3	73.2	3.1	111.3	-	-
2017/2018	SECOND	783.5	90.3	-	111.2	.	2.9	27.7	33.0	59.5	76.6	24.3	20.9	34.1	4.5	-	-
2017/2018	THIRD	314.3	105.6	-	205.1	16.3	40.8	82.2	76.0	94.4	141.5	14.6	125.3	209.1	26.9	-	-
2018/2019	BASE	67,273.7	14,294.6	-	24,039.7	2,405.1	1,728.5	2,132.8	3,168.0	5,478.7	7,913.5	2,258.1	23,320.4	3,296.9	9,565.5	-	-
2018/2019	FIRST	260.5	831.3	-	178.5	.	29.0	38.2	27.9	58.7	582.5	27.9	468.6	4.5	37.7	-	-
2018/2019	SECOND	580.7	148.0	-	515.2	.	5.6	26.7	22.9	117.9	81.1	37.9	338.2	5.6	498.2	-	-
2018/2019	THIRD	1,433.2	253.2	-	372.8	27.6	67.1	101.3	199.9	229.5	245.1	16.4	1,156.4	50.0	44.7	-	-
2019/2020	BASE	69,128.4	13,101.5	-	23,715.8	2,406.7	1,598.5	2,249.7	3,228.9	6,248.4	8,202.1	2,089.0	22,971.4	2,739.5	9,649.6	-	-
2019/2020	FIRST	823.8	249.4	-	78.7	0.0	11.7	10.6	28.8	43.6	96.9	50.6	711.4	31.9	157.7	-	-
2019/2020	SECOND	473.0	160.4	-	229.4	20.0	21.2	18.8	44.8	41.9	229.7	33.9	105.8	87.5	146.2	-	-
2019/2020	THIRD	2,037.4	529.7	-	286.9	3.4	2.4	159.2	23.2	80.6	232.8	221.4	867.4	254.8	1,127.8	-	-
2020/2021	BASE	61,457.0	15,488.6	-	22,926.7	2,138.9	1,647.2	2,126.5	2,975.4	5,987.1	8,068.8	1,857.9	24,109.2	2,380.6	10,370.1	1,528.0	2,445.1
2020/2021	FIRST	1,317.8	331.4	-	181.0	32.5	38.9	5.5	32.1	70.1	389.4	277.5	653.7	38.7	83.5	81.9	20.3
2021/2022	BASE	61,395.2	16,679.9	.	22,286.8	2,220.2	1,673.8	2,237.7	3,134.1	6,013.2	6,762.4	1,248.1	22,358.1	1,980.6	11,253.8	1,637.4	2,746.1

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

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	$93.62	$75.83	$140.05
APS	$158.20	$93.62	$75.83	$140.05
ATSI	$148.42	$92.97	$74.98	$171.32
Cleveland	$158.68	$89.17	$72.16	$171.33
ComEd	$199.02	$188.90	$184.32	$195.55
DAY	$158.20	$93.62	$74.82	$140.00
DEOK	$158.20	$93.62	$129.12	$140.00
DLCO	$158.20	$93.62	$75.83	$140.05
Dominion	$158.20	$93.62	$75.83	$140.05
EKPC	$158.20	$93.62	$75.83	$140.05
MAAC				
EMAAC				
AECO	$214.31	$112.48	$186.61	$165.68
DPL	$214.31	$112.48	$186.61	$165.68
DPL South	$211.38	$115.95	$184.53	$165.73
JCPL	$214.31	$112.48	$186.61	$165.68
PECO	$214.31	$112.48	$186.61	$165.68
PSEG	$210.92	$110.56	$187.39	$204.20
PSEG North	$211.71	$116.03	$186.33	$204.27
RECO	$214.31	$112.48	$186.61	$165.68
SWMAAC				
BGE	$141.58	$88.20	$85.24	$199.00
Pepco	$144.90	$90.59	$85.54	$140.00
WMAAC				
Met-Ed	$152.65	$93.81	$85.16	$140.00
PENELEC	$152.65	$93.81	$85.16	$140.00
PPL	$147.90	$88.53	$85.70	$140.08

Table 5-20 RPM revenue by type: 2007/2008 through 2021/2022[65] [66]

				Coal		Gas		Hydroelectric		Nuclear	
	Demand Resources	Energy Efficiency Resources	Imports	Existing	New/repower/ reactivated	Existing	New/repower/ reactivated	Existing	New/repower/ reactivated	Existing	New/repower/ reactivated
2007/2008	$5,537,085	$0	$22,225,980	$1,019,060,206	$0	$1,625,158,046	$3,516,075	$209,490,444	$0	$996,085,233	$0
2008/2009	$35,349,116	$0	$60,918,903	$1,835,059,769	$0	$2,115,862,522	$9,784,064	$287,838,147	$12,255	$1,322,601,837	$0
2009/2010	$65,762,003	$0	$56,517,793	$2,409,315,953	$1,854,781	$2,551,967,501	$30,168,831	$364,731,344	$11,173	$1,517,723,628	$0
2010/2011	$60,235,796	$0	$106,046,871	$2,648,278,766	$3,168,069	$2,829,039,737	$58,065,964	$442,410,730	$19,085	$1,799,258,125	$0
2011/2012	$55,795,785	$139,812	$185,421,273	$1,586,775,249	$28,330,047	$1,721,272,563	$98,448,693	$278,529,660	$0	$1,079,386,338	$0
2012/2013	$264,387,897	$11,408,552	$13,260,822	$1,014,858,378	$7,568,127	$1,256,600,367	$76,633,409	$179,117,374	$11,998	$762,719,550	$0
2013/2014	$558,715,114	$21,598,174	$31,804,645	$1,741,613,525	$12,950,135	$2,154,401,813	$167,844,235	$308,853,673	$25,708	$1,346,223,419	$0
2014/2015	$681,315,139	$42,308,549	$135,573,409	$1,935,468,356	$57,078,818	$2,176,442,220	$205,555,569	$333,941,614	$6,649,774	$1,464,950,862	$0
2015/2016	$903,496,003	$66,652,986	$260,806,674	$2,902,870,267	$63,682,708	$2,676,692,075	$535,039,154	$389,540,948	$15,478,144	$1,850,033,226	$0
2016/2017	$466,952,356	$68,709,670	$244,091,507	$2,137,545,515	$72,217,195	$2,217,027,225	$667,098,133	$283,613,426	$13,927,638	$1,483,759,630	$0
2017/2018	$515,145,457	$86,147,605	$218,710,769	$2,452,687,763	$62,790,145	$2,550,970,172	$984,733,791	$348,972,234	$15,219,121	$1,694,447,711	$0
2018/2019	$637,742,320	$103,105,796	$263,475,004	$2,637,322,434	$77,072,397	$2,992,482,882	$1,444,760,231	$416,075,805	$15,382,098	$2,004,607,689	$0
2019/2020	$375,353,169	$92,569,666	$84,207,557	$1,679,065,727	$47,569,776	$1,960,634,807	$1,061,191,651	$250,101,011	$6,311,022	$1,283,332,540	$0
2020/2021	$343,544,146	$93,092,140	$74,256,199	$1,318,324,680	$36,115,158	$2,080,256,094	$1,146,062,527	$209,060,912	$7,737,607	$1,421,992,631	$0
2021/2022	$631,409,762	$166,627,498	$130,197,690	$2,079,667,778	$66,256,260	$2,670,256,030	$1,676,705,702	$295,309,520	$11,589,480	$1,181,920,902	$0

				Oil		Solar		Solid waste		Wind		
	Demand Resources	Energy Efficiency Resources	Imports	Existing	New/repower/ reactivated	Existing	New/repower/ reactivated	Existing	New/repower/ reactivated	Existing	New/repower/ reactivated	Total revenue
2007/2008	$5,537,085	$0	$22,225,980	$339,272,020	$0	$0	$0	$31,512,230	$0	$430,065	$0	$4,252,287,381
2008/2009	$35,349,116	$0	$60,918,903	$375,774,257	$4,837,523	$0	$0	$35,011,991	$0	$1,180,153	$2,917,048	$6,087,147,586
2009/2010	$65,762,003	$0	$56,517,793	$447,358,085	$5,676,582	$0	$0	$42,758,762	$523,739	$2,011,156	$6,836,827	$7,503,218,157
2010/2011	$60,235,796	$0	$106,046,871	$440,593,115	$4,339,539	$0	$0	$40,731,606	$413,503	$1,819,413	$15,232,177	$8,449,652,496
2011/2012	$55,795,785	$139,812	$185,421,273	$263,061,402	$967,887	$0	$66,978	$25,636,836	$261,690	$1,072,929	$9,919,881	$5,335,087,023
2012/2013	$264,387,897	$11,408,552	$13,260,822	$248,107,065	$2,772,987	$0	$1,246,337	$26,840,670	$316,420	$812,644	$5,052,036	$3,871,714,635
2013/2014	$558,715,114	$21,598,174	$31,804,645	$385,720,626	$5,670,399	$0	$3,523,555	$43,943,130	$1,977,705	$1,373,205	$13,538,988	$6,799,778,047
2014/2015	$681,315,139	$42,308,549	$135,573,409	$319,758,617	$4,106,697	$0	$3,836,582	$34,281,137	$1,709,533	$1,524,551	$32,766,219	$7,437,267,646
2015/2016	$903,496,003	$66,652,986	$260,806,674	$397,556,965	$5,947,275	$0	$7,064,983	$35,862,368	$6,179,607	$1,829,269	$42,994,253	$10,161,726,902
2016/2017	$466,952,356	$68,709,670	$244,091,507	$261,495,016	$4,030,823	$0	$7,057,256	$32,648,789	$6,380,604	$1,144,873	$26,189,042	$7,993,888,695
2017/2018	$515,145,457	$86,147,605	$218,710,769	$276,148,715	$3,888,126	$0	$10,899,883	$34,771,100	$9,036,976	$1,529,251	$40,577,901	$9,306,676,719
2018/2019	$637,742,320	$103,105,796	$263,475,004	$339,771,633	$2,922,855	$0	$16,928,323	$38,243,467	$9,658,138	$1,166,553	$54,226,228	$11,054,943,851
2019/2020	$375,353,169	$92,569,666	$84,207,557	$187,076,264	$1,818,114	$610,166	$12,246,100	$21,332,647	$5,326,702	$1,296,846	$46,582,019	$7,116,625,781
2020/2021	$343,544,146	$93,092,140	$74,256,199	$212,589,855	$1,408,492	$0	$7,389,376	$26,917,827	$5,428,707	$25,124	$35,671,349	$7,019,872,821
2021/2022	$631,409,762	$166,627,498	$130,197,690	$253,987,440	$2,401,396	$0	$29,673,108	$31,924,862	$7,757,690	$2,089,282	$63,102,701	$9,300,877,101

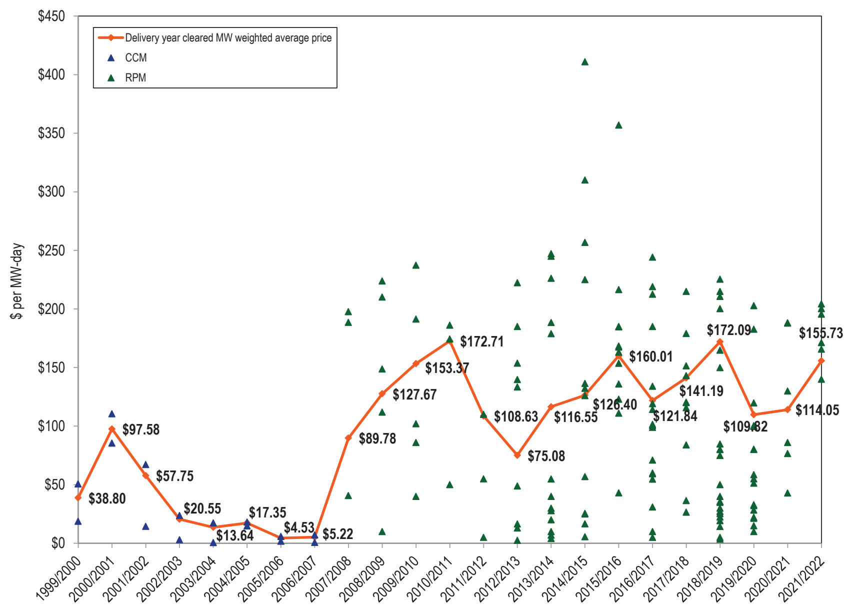
65 A resource classified as "new/repower/reactivated" is a capacity resource addition since the implementation of RPM and is considered "new/repower/reactivated" for its initial offer and all its subsequent offers in RPM Auctions.
66 The results for the ATSI Integration Auctions are not included in this table.

Table 5-21 RPM revenue by calendar year: 2007 through 2022[67]

Year	Weighted Average RPM Price ($ per MW-day)	Weighted Average Cleared UCAP (MW)	Effective Days	RPM Revenue
2007	$89.78	129,409.2	214	$2,486,310,108
2008	$111.93	130,223.2	366	$5,334,880,241
2009	$142.74	132,772.0	365	$6,917,391,702
2010	$164.71	134,033.9	365	$8,058,113,907
2011	$135.14	134,105.2	365	$6,615,032,130
2012	$89.01	137,684.7	366	$4,485,656,150
2013	$99.39	154,044.3	365	$5,588,442,225
2014	$122.32	160,668.7	365	$7,173,539,072
2015	$146.10	169,112.0	365	$9,018,343,604
2016	$137.69	176,742.6	366	$8,906,998,628
2017	$133.19	180,272.0	365	$8,763,578,112
2018	$159.31	177,680.6	365	$10,331,688,133
2019	$135.58	176,503.3	365	$8,734,502,333
2020	$112.29	172,057.9	366	$7,071,299,627
2021	$138.49	165,333.1	365	$8,357,228,755
2022	$155.73	163,627.3	151	$3,847,760,116

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

Figure 5-7 History of capacity prices: 1999/2000 through 2021/2022[68]



68 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.

Figure 5-8 Map of RPM capacity prices: 2018/2019 through 2021/2022

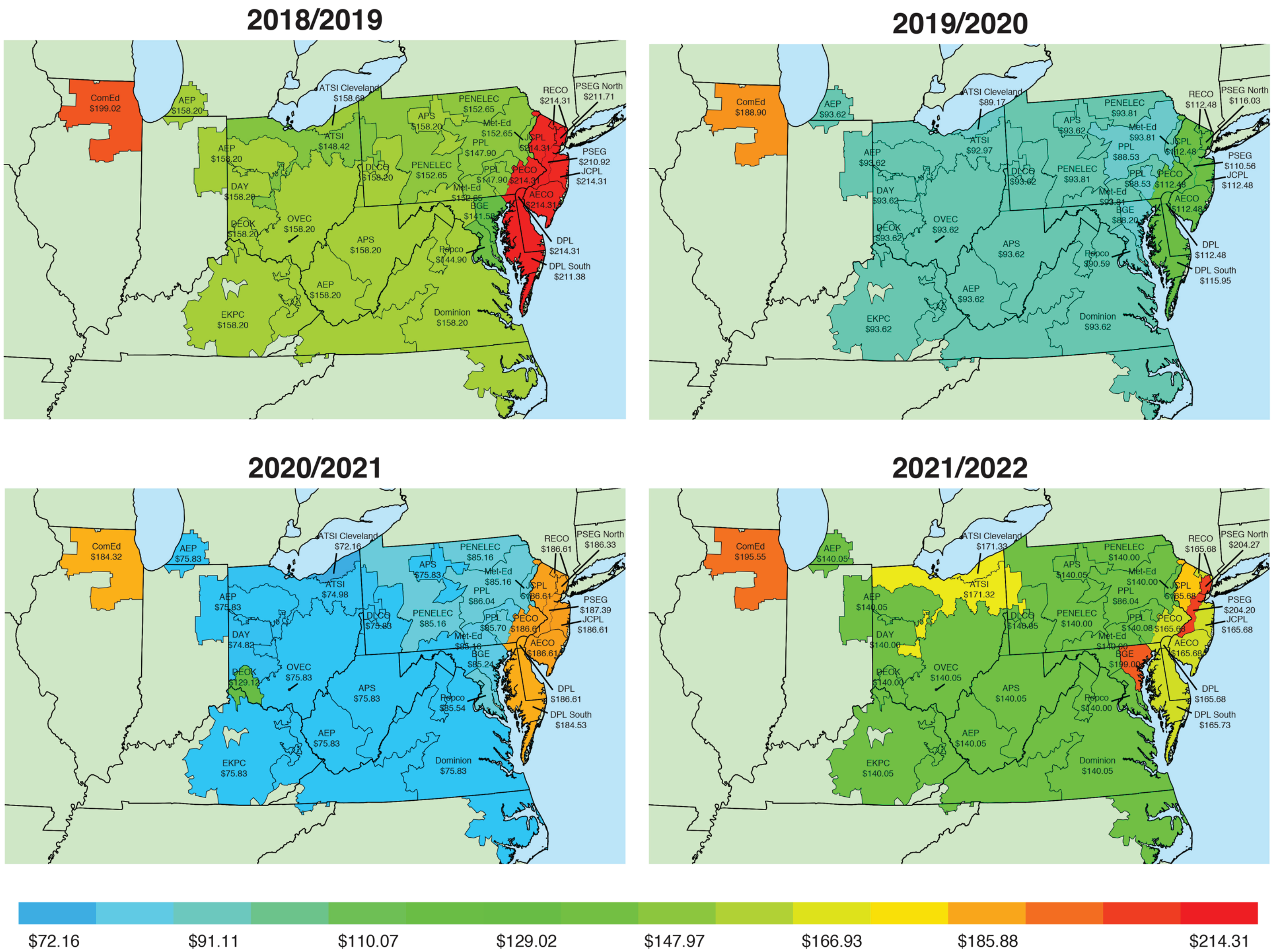


Table 5-22 RPM cost to load: 2018/2019 through 2021/2022 RPM Auctions[69 70 71]

	Net Load Price ($ per MW-day)	UCAP Obligation (MW)	Annual Charges
2018/2019			
Rest of RTO	$164.70	80,837.7	$4,859,734,465
Rest of MAAC	$218.98	31,118.9	$2,487,249,930
BGE	$158.20	7,701.4	$444,710,759
DPL	$219.29	4,463.7	$357,277,053
ComEd	$212.03	24,752.4	$1,915,591,298
Pepco	$156.90	7,329.2	$419,746,111
PPL	$155.11	8,300.9	$469,969,694
Total		164,504.2	$10,954,279,310
2019/2020			
Rest of RTO	$98.07	89,185.9	$3,201,364,940
Rest of EMAAC	$115.58	24,415.1	$1,032,810,556
BGE	$97.79	7,595.2	$271,828,430
ComEd	$192.56	24,985.1	$1,760,892,086
Pepco	$92.90	7,330.3	$249,230,694
PSEG	$115.83	11,281.1	$478,247,326
Total		164,792.8	$6,994,374,033
2020/2021			
Rest of RTO	$77.00	69,538.0	$1,954,438,669
Rest of MAAC	$86.89	29,572.5	$937,886,000
Rest of EMAAC	$176.17	34,949.0	$2,247,251,699
ComEd	$183.79	25,040.0	$1,679,743,111
DEOK	$103.53	5,208.1	$196,815,744
Total		164,307.7	$7,016,135,223
2021/2022			
Rest of RTO	$140.53	82,080.4	$4,210,274,861
Rest of EMAAC	$163.08	23,762.8	$1,414,495,718
ATSI	$157.99	14,464.9	$834,165,114
BGE	$161.62	7,435.0	$438,596,021
ComEd	$192.69	24,983.0	$1,757,064,009
PSEG	$184.03	10,901.1	$732,248,951
Total		163,627.3	$9,386,844,675

69 The RPM annual charges are calculated using the rounded, net load prices as posted in the PJM RPM Auction results.
70 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.
71 The Net Load Prices and obligation MW for 2020/2021 and 2021/2022 are not finalized.

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.[72] 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.[73 74]

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 5-23 shows the capacity factors by unit type for the first three months of 2018 and 2019. In the first three months of 2019, nuclear units had a capacity factor of 94.3 percent, compared to 95.4 percent in the first three months of 2018; combined cycle units had a capacity factor of 64.4 percent in the first three months of

72 OATT Part V.
73 *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.").
74 For an explanation of the RMR rules, see *2018 State of the Market Report for PJM*, Section 5 Capacity Market, at Reliability Must Run (RMR) Service. <http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2018/2018-som-pjm-sec5.pdf>

2019, compared to a capacity factor of 63.1 percent in the first three months of 2018; all steam units had a capacity factor of 40.5 percent in the first three months of 2019, compared to 43.3 percent in the first three months of 2018; coal units had a capacity factor of 46.3 percent in the first three months of 2019, compared to 50.0 percent in the first three months of 2018.

Table 5-23 Capacity factor (By unit type (GWh)): January through March, 2018 and 2019[75] [76]

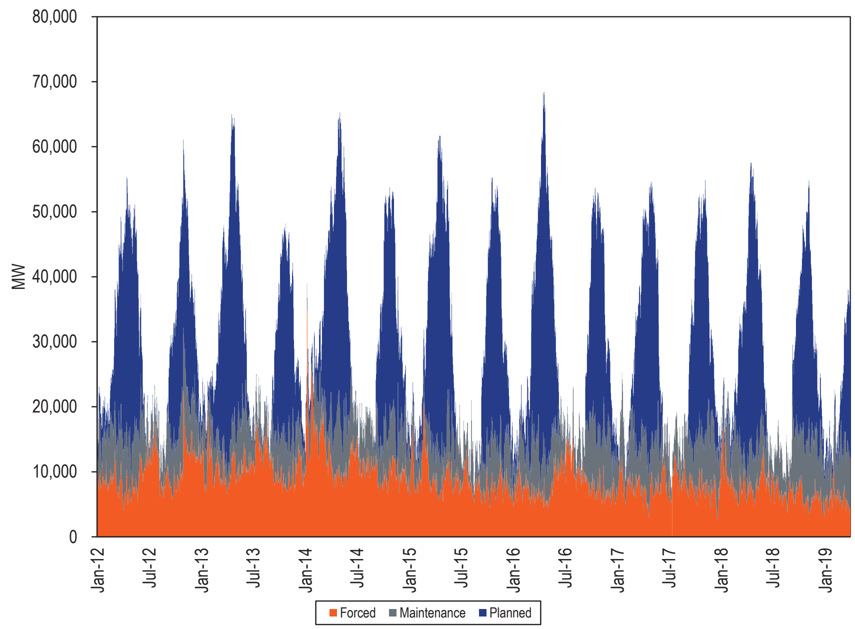
	2018 (Jan-Mar)		2019 (Jan-Mar)		Change in 2019 from 2018
Unit Type	Generation (GWh)	Capacity Factor	Generation (GWh)	Capacity Factor	
Battery	3.7	0.6%	6.1	0.8%	0.2%
Combined Cycle	52,815.8	63.1%	67,773.2	64.4%	1.3%
Single Fuel	44,365.8	69.5%	59,802.5	72.4%	2.9%
Dual Fuel	8,450.1	42.5%	7,970.7	35.2%	(7.3%)
Combustion Turbine	2,906.3	5.0%	1,701.3	2.9%	(2.1%)
Single Fuel	1,836.1	4.3%	1,268.0	3.0%	(1.3%)
Dual Fuel	1,070.1	6.8%	433.3	2.6%	(4.2%)
Diesel	76.8	10.1%	44.6	6.1%	(4.0%)
Single Fuel	70.9	10.6%	43.1	6.8%	(3.8%)
Dual Fuel	5.9	6.6%	1.5	1.7%	(4.9%)
Diesel (Landfill gas)	456.2	53.7%	423.2	52.6%	(1.1%)
Fuel Cell	55.8	85.3%	56.7	85.2%	(0.1%)
Nuclear	71,827.2	95.4%	69,798.2	94.3%	(1.0%)
Pumped Storage Hydro	1,327.2	12.2%	1,136.2	10.4%	(1.7%)
Run of River Hydro	2,522.7	39.3%	3,821.8	58.8%	19.5%
Solar	389.7	13.7%	495.0	14.7%	0.9%
Steam	68,906.2	43.3%	59,193.4	40.5%	(2.8%)
Biomass	1,644.0	69.9%	1,409.7	66.6%	(3.4%)
Coal	65,795.9	50.0%	56,751.7	46.3%	(3.7%)
Single Fuel	64,068.5	51.5%	55,707.2	48.3%	(3.2%)
Dual Fuel	1,727.4	23.8%	1,044.4	14.4%	(9.4%)
Natural Gas	1,279.7	6.3%	1,028.6	6.1%	(0.2%)
Single Fuel	134.9	6.3%	102.3	13.8%	7.5%
Dual Fuel	1,144.7	6.3%	926.3	5.8%	(0.5%)
Oil	186.7	4.0%	3.5	0.1%	(3.9%)
Wind	7,395.3	40.4%	7,307.2	36.6%	(3.8%)
Total	208,684.4	50.0%	211,758.3	49.5%	(0.5%)

75 The capacity factors in this table are based on nameplate capacity values, and are calculated based on when the units come on line.
76 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.

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 5-9, 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 5-12.

Figure 5-9 Outages (MW): January 2012 through March 2019



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 5-10. Metrics by unit type are shown in Table 5-24.

Figure 5-10 Equivalent outage and availability factors: January through March, 2007 through 2019

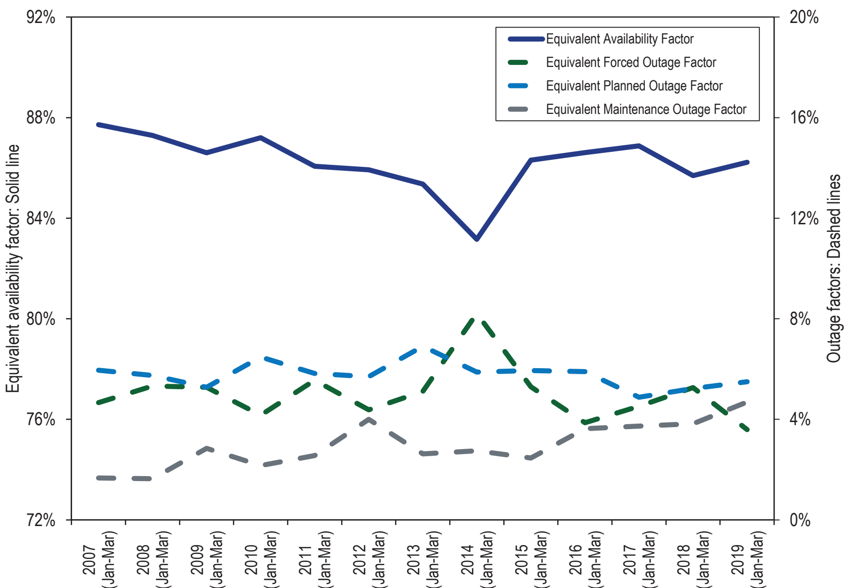


Table 5-24 EFOF, EPOF, EMOF and EAF by unit type: January through March, 2007 through 2019

	Coal				Combined Cycle				Combustion Turbine				Diesel				Hydroelectric				Nuclear				Other			
	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 (Jan-Mar)	6.8%	7.8%	2.0%	83.4%	1.0%	6.8%	1.1%	91.1%	6.6%	2.2%	2.3%	88.9%	8.0%	0.3%	1.6%	90.2%	1.3%	7.3%	2.0%	89.5%	0.4%	4.7%	0.4%	94.5%	7.2%	6.0%	2.3%	84.6%
2008 (Jan-Mar)	8.6%	5.6%	2.1%	83.7%	1.8%	2.9%	1.5%	93.8%	3.3%	3.8%	1.3%	91.6%	10.1%	0.2%	0.9%	88.8%	1.2%	8.7%	0.6%	89.5%	1.4%	6.9%	0.7%	91.0%	7.7%	8.4%	2.8%	81.1%
2009 (Jan-Mar)	7.0%	6.2%	3.4%	83.4%	3.6%	5.9%	3.5%	86.9%	1.5%	2.9%	1.9%	93.7%	6.6%	0.2%	1.7%	91.5%	1.5%	10.0%	1.2%	87.2%	3.8%	3.2%	1.0%	92.0%	9.9%	6.6%	6.0%	77.6%
2010 (Jan-Mar)	6.3%	7.7%	3.6%	82.4%	1.5%	6.0%	2.3%	90.2%	2.4%	1.8%	1.3%	94.5%	4.1%	0.7%	0.7%	94.5%	0.7%	10.1%	1.5%	87.7%	0.7%	6.7%	0.4%	92.3%	9.1%	7.2%	1.6%	82.2%
2011 (Jan-Mar)	9.3%	7.4%	4.1%	79.3%	3.0%	8.3%	1.3%	87.4%	1.6%	2.6%	1.7%	94.1%	2.5%	0.0%	3.6%	93.9%	1.7%	9.5%	0.9%	88.0%	1.5%	4.0%	0.7%	93.8%	9.2%	4.6%	3.5%	82.8%
2012 (Jan-Mar)	7.0%	7.4%	7.5%	78.1%	1.7%	6.1%	1.9%	90.2%	1.6%	2.2%	1.3%	94.9%	1.9%	0.0%	0.8%	97.3%	1.6%	4.8%	1.4%	92.2%	0.9%	5.3%	0.5%	93.3%	8.8%	4.8%	3.5%	82.9%
2013 (Jan-Mar)	6.8%	10.0%	4.1%	79.1%	1.9%	9.9%	3.3%	85.0%	5.3%	2.8%	0.8%	91.1%	3.7%	0.1%	1.1%	95.1%	0.4%	3.5%	2.3%	93.8%	0.5%	3.7%	0.3%	95.6%	13.5%	5.7%	3.6%	77.2%
2014 (Jan-Mar)	9.9%	4.9%	4.1%	81.1%	4.3%	10.3%	1.4%	83.9%	14.3%	3.2%	1.2%	81.3%	14.8%	0.0%	2.7%	82.4%	1.1%	9.3%	5.6%	84.1%	1.6%	5.8%	0.3%	92.3%	13.0%	7.9%	5.4%	73.7%
2015 (Jan-Mar)	8.2%	5.2%	4.0%	82.6%	2.8%	7.4%	1.7%	88.1%	3.4%	3.6%	1.2%	91.8%	9.9%	0.3%	1.9%	87.9%	2.0%	9.6%	1.4%	87.0%	1.4%	5.1%	0.5%	92.9%	9.8%	10.7%	4.0%	75.5%
2016 (Jan-Mar)	7.1%	6.7%	7.0%	79.2%	2.1%	4.3%	1.5%	92.1%	2.2%	2.3%	1.8%	93.6%	5.9%	0.0%	2.9%	91.3%	2.2%	5.0%	3.7%	89.0%	0.8%	4.8%	1.1%	93.3%	4.7%	13.7%	3.4%	78.2%
2017 (Jan-Mar)	10.8%	5.8%	7.6%	75.8%	2.2%	4.8%	1.3%	91.7%	1.0%	2.7%	1.8%	94.5%	4.1%	0.2%	1.4%	94.3%	2.6%	5.3%	3.4%	88.8%	0.4%	5.5%	0.5%	93.6%	2.5%	4.1%	4.6%	88.8%
2018 (Jan-Mar)	11.5%	6.4%	8.0%	74.0%	1.8%	4.3%	1.1%	92.8%	2.1%	3.4%	1.6%	93.0%	5.8%	0.7%	2.8%	90.8%	3.4%	4.0%	2.0%	90.6%	0.3%	5.1%	0.3%	94.4%	5.8%	6.7%	5.8%	81.8%
2019 (Jan-Mar)	7.1%	3.6%	9.5%	79.8%	1.3%	6.5%	1.8%	90.4%	1.5%	4.2%	2.0%	92.3%	5.2%	1.1%	2.9%	90.7%	1.0%	6.9%	3.0%	89.2%	0.5%	9.2%	0.7%	89.6%	7.4%	3.6%	7.9%	81.1%

Generator Forced Outage Rates

There are three primary forced outage rate metrics. The most fundamental forced outage rate metric is EFORd. The other forced outage rate metrics either exclude some outages, XEFORd, or exclude some outages and exclude some time periods, EFORp. The other outage rate metrics will no longer be used under the capacity performance capacity market design.

The unadjusted forced outage rate of a generating unit is measured as 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.[77] The EFORd metric includes all forced outages, regardless of the reason for those outages.

The average PJM EFORd for the first three months of 2019 was 7.0 percent, a decrease from 9.0 percent for the first three months of 2018. Figure 5-11 shows the average EFORd since 1999 for all units in PJM.[78]

77 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.

78 The universe of units in PJM changed as the PJM footprint expanded and as units retired from and entered PJM markets. See the *2018 State of the Market Report for PJM*, Appendix A: "PJM Geography" for details.

Figure 5-11 Trends in the equivalent demand forced outage rate (EFORd): 1999 through 2019

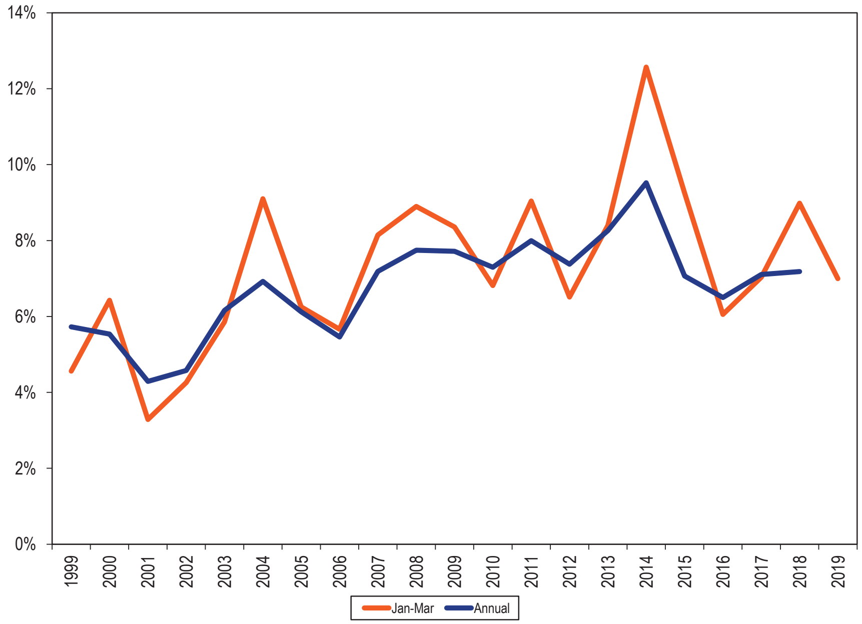


Table 5-25 shows the class average EFORd by unit type.

Table 5-25 EFORd data for different unit types: January through March, 2007 through 2019

	Jan-Mar												
	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Coal	7.5%	9.2%	8.1%	7.8%	10.9%	8.8%	8.2%	10.9%	9.4%	9.1%	14.2%	14.3%	10.9%
Combined Cycle	5.9%	5.4%	4.7%	2.4%	4.0%	2.3%	2.3%	7.5%	5.1%	2.8%	2.6%	3.2%	2.8%
Combustion Turbine	22.2%	16.9%	13.4%	12.5%	12.1%	9.1%	19.6%	29.7%	18.1%	8.4%	7.0%	10.6%	8.7%
Diesel	9.0%	10.0%	8.1%	6.2%	5.1%	2.7%	3.8%	15.5%	11.0%	7.5%	5.5%	6.2%	5.7%
Hydroelectric	1.9%	2.9%	2.0%	1.0%	2.1%	2.7%	0.6%	1.4%	2.3%	3.3%	3.2%	3.7%	1.2%
Nuclear	0.4%	1.5%	3.8%	0.7%	1.6%	0.9%	0.5%	1.7%	1.5%	0.9%	0.5%	0.3%	0.6%
Other	10.2%	15.9%	16.4%	12.7%	19.7%	10.2%	18.5%	24.4%	18.8%	8.5%	5.9%	18.1%	15.0%
Total	8.1%	8.9%	8.4%	6.8%	9.0%	6.5%	8.4%	12.6%	9.2%	6.1%	7.0%	9.0%	7.0%

Other Forced Outage Rate Metrics

There are a number of performance incentives in the current capacity market design, but they fall short of the incentives that a unit would face if it earned all its revenue in an energy market. These incentives will change when the capacity performance capacity market design is implemented beginning with the 2018/2019 Delivery Year but remain essential reasons why the incentive components of capacity performance design were necessary.

Currently, there are two additional forced outage rate metrics that play a significant role in PJM markets, XEFORd and EFORp. Under the capacity performance modifications to RPM, neither XEFORd nor EFORp will be relevant.

The XEFORd metric is the EFORd metric adjusted to remove outages that have been defined to be outside management control (OMC). Under the capacity performance modifications to RPM, all outages will be included in the EFORd metric used to determine the level of unforced capacity for specific units that must be offered in PJM's Capacity Market, including the outages previously designated as OMC. OMC outages will no longer be excluded from the EFORd calculations.

The EFORp metric is the EFORd metric adjusted to remove OMC outages and to reflect unit availability only during the approximately 500 hours defined in the PJM RPM tariff to be the critical load hours. Under the capacity performance modifications to RPM, EFORp will no longer be used to calculate performance penalties.

Current PJM capacity market rules use XEFORd to determine the UCAP for generating units. Unforced capacity in the PJM Capacity Market for any individual generating unit is equal to one minus the XEFORd multiplied by the unit ICAP.

The current PJM capacity market rules create an incentive to minimize the forced outage rate excluding OMC outages, but not an incentive to minimize the forced outage rate accounting for all forced outages. In fact, because PJM uses XEFORd as the outage metric to define capacity available for sale, the current PJM Capacity Market includes an incentive to classify as many forced outages as possible as OMC. That incentive is removed in the capacity performance design.

Outages Deemed Outside Management Control

OMC outages will continue to be excluded from outage rate calculations through the end of the 2017/2018 Delivery Year. Under the capacity performance modifications to RPM, effective with the 2018/2019 Delivery Year, OMC outages will no longer be excluded from the EFORd metric used to determine the level of unforced capacity for specific units that must be offered in PJM's Capacity Market. All forced outages will be included.[79]

Table 5-26 shows OMC forced outages by cause code, as classified by PJM. OMC forced outages accounted for 3.1 percent of all forced outages in the first three months of 2019. The largest contributor to OMC outages, wet coal, was the cause of 38.6 percent of OMC outages and 1.2 percent of all forced outages.

79 "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Schedule 5.B.

Table 5-26 OMC outages: January through March, 2019

OMC Cause Code	Percent of OMC Forced Outages	Percent of all Forced Outages
Wet coal	38.6%	1.2%
Other miscellaneous external problems	13.4%	0.4%
Lack of fuel	10.8%	0.3%
Switchyard system protection devices	8.6%	0.3%
Switchyard circuit breakers	7.6%	0.2%
Storms	4.7%	0.1%
Transmission system problems other than catastrophes	4.6%	0.1%
Transmission line	4.2%	0.1%
Flood	2.5%	0.1%
Other fuel quality problems	1.7%	0.1%
Frozen coal	1.6%	0.0%
High ash content	1.1%	0.0%
Other switchyard equipment	0.5%	0.0%
Transmission equipment beyond the 1st substation	0.1%	0.0%
Lack of water (hydro)	0.1%	0.0%
Low Btu oil	0.0%	0.0%
Fire; not related to a specific component	0.0%	0.0%
Lightning	0.0%	0.0%
Total	100.0%	3.1%

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.[80] On a system wide basis, the resultant lost equivalent availability from the forced outages is equal to the equivalent forced outage factor (EFOF).[81]

PJM EFOF was 4.4 percent in the first three months of 2019. This means there was 5.5 percent lost availability because of forced outages. Table 5-27 shows that forced outages for boiler tube leaks, at 18.9 percent of the systemwide EFOF, were the largest single contributor to EFOF.

80 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.
81 EFOF incorporates all outages regardless of their designation as OMC.

Table 5-27 Contribution to EFOF by unit type by cause: January through March, 2019

	Coal	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Other	System
Boiler Tube Leaks	25.5%	9.8%	0.0%	0.0%	0.0%	0.0%	7.5%	18.9%
Economic	0.0%	1.9%	27.9%	2.1%	3.2%	0.0%	58.7%	11.9%
Boiler Fuel Supply from Bunkers to Boiler	14.2%	0.1%	0.0%	0.0%	0.0%	0.0%	1.3%	9.8%
Boiler Air and Gas Systems	6.9%	0.0%	0.0%	0.0%	0.0%	0.0%	10.7%	6.5%
Electrical	6.7%	1.4%	11.1%	2.0%	3.3%	16.8%	2.2%	6.2%
Miscellaneous (Pollution Control Equipment)	8.8%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	5.9%
Unit Testing	3.3%	0.1%	3.4%	40.3%	16.4%	9.1%	4.7%	3.9%
Fuel Quality	4.4%	0.2%	0.0%	4.2%	0.0%	0.0%	0.7%	3.1%
Feedwater System	3.1%	1.5%	0.0%	0.0%	0.0%	4.7%	3.9%	3.0%
Auxiliary Systems	2.4%	6.9%	14.8%	0.0%	0.0%	1.1%	0.1%	2.9%
Boiler Piping System	3.5%	3.5%	0.0%	0.0%	0.0%	0.0%	0.0%	2.5%
Slag and Ash Removal	3.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.8%	2.4%
Miscellaneous (Generator)	1.2%	5.5%	4.8%	2.2%	2.2%	0.0%	0.9%	1.6%
Exciter	0.5%	2.8%	0.5%	0.1%	1.0%	28.3%	1.1%	1.6%
Fuel, Ignition and Combustion Systems	0.0%	9.6%	15.9%	0.0%	0.0%	0.0%	0.0%	1.5%
Boiler Internals and Structures	2.0%	0.4%	0.0%	0.0%	0.0%	0.0%	0.0%	1.4%
Lube Oil	2.0%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	1.3%
Condensing System	1.4%	6.1%	0.0%	0.0%	0.0%	0.0%	0.1%	1.3%
Generator	0.0%	20.0%	3.6%	1.1%	0.6%	0.0%	0.0%	1.3%
All Other Causes	10.6%	30.1%	18.1%	48.0%	73.2%	40.0%	7.3%	13.3%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Table 5-28 shows the categories which are included in the economic category.[82] Lack of fuel that is considered outside management control accounted for 2.8 percent of all economic reasons.

OMC lack of fuel is described as "Lack of fuel where the operator is not in control of contracts, supply lines, or delivery of fuels."[83] Only a handful of units use other economic problems to describe outages. Other economic problems are not defined by NERC GADS and are best described as economic problems that cannot be classified by the other NERC GADS economic problem cause codes. Lack of water events occur when a hydroelectric plant does not have sufficient fuel (water) to operate.

Table 5-28 Contributions to economic outages: January through March, 2019

	Contribution to Economic Reasons
Lack of fuel (Non-OMC)	95.3%
Lack of fuel (OMC)	2.8%
Problems with primary fuel for units with secondary fuel operation	0.9%
Other economic problems	0.8%
Wet fuel (biomass)	0.1%
Fuel conservation	0.1%
Lack of water (hydro)	0.0%
Total	100.0%

82 The definitions of these outages are defined by NERC GADS.
83 The definitions of these outages are defined by NERC GADS.

EFORd, XEFORd and EFORp

The equivalent forced outage rate during peak hours (EFORp) is a measure of the probability that a generating unit will fail, either partially or totally, to perform when it is needed to operate during the peak hours of the day in the peak months of January, February, June, July and August. EFORp is calculated using historical performance data and is designed to measure if a unit would have run had the unit not been forced out. Like XEFORd, EFORp excludes OMC outages. PJM systemwide EFORp is a capacity-weighted average of individual unit EFORp.

Until the capacity performance market design is fully implemented for the 2020/2021 Delivery Year, EFORp will be used in the calculation of nonperformance charges for units that are not capacity performance capacity resources. Under capacity performance, EFORp will not be used.

EFORd, XEFORd and EFORp are designed to measure the rate of forced outages, which are defined as outages that cannot be postponed beyond the end of the next weekend.[84] It is reasonable to expect that units have some degree of control over when to take a forced outage, depending on the underlying cause of the forced outage. If units had no control over the timing of forced outages, outages during peak hours of the peak months would be expected to occur at roughly the same rate as outages during periods of demand throughout the rest of the year. With the exception of hydroelectric and nuclear units, EFORp is lower than XEFORd, suggesting that units elect to take non-OMC forced outages during off-peak hours, as much as it is within their ability to do so. That is consistent with the incentives created by the PJM Capacity Market but it does not directly address the question of the incentive effect of omitting OMC outages from the EFORp metric.

Table 5-29 shows the capacity-weighted class average of EFORd, XEFORd and EFORp.

Table 5-29 EFORd, XEFORd and EFORp data by unit type: January through March, 2019[85]

	EFORd	XEFORd	EFORp	Difference EFORd and XEFORd	Difference EFORd and EFORp
Coal	10.9%	10.7%	6.3%	0.2%	4.6%
Combined Cycle	2.8%	2.6%	1.3%	0.2%	1.5%
Combustion Turbine	8.7%	7.5%	4.4%	1.2%	4.4%
Diesel	5.7%	5.6%	4.2%	0.1%	1.6%
Hydroelectric	1.2%	1.1%	1.5%	0.2%	(0.3%)
Nuclear	0.6%	0.6%	0.8%	0.0%	(0.1%)
Other	15.0%	14.4%	1.5%	0.6%	13.5%
Total	7.0%	6.6%	3.3%	0.4%	3.7%

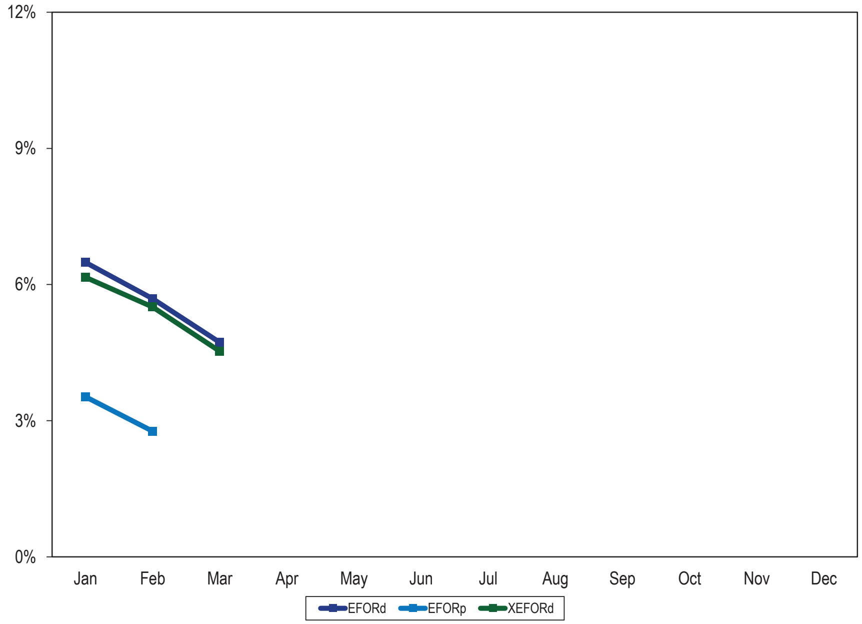
Performance by Month

On a monthly basis, EFORp values were less than EFORd and XEFORd values as shown in Figure 5-12, demonstrating that units had fewer non-OMC outages during peak hours than would have been expected based on EFORd.

84 See "PJM Manual 22: Generator Resource Performance Indices," Rev. 17 (April 1, 2017), Definitions.

85 EFORp is only calculated for the peak months of January, February, June, July and August.

Figure 5-12 EFORd, XEFORd and EFORp: January through March, 2019



On a monthly basis, unit availability as measured by the equivalent availability factor is shown in Figure 5-13.

Figure 5-13 Monthly generator performance factors: January through March 2019