## BEFORE
## THE PUBLIC UTILITIES COMMISSION OF OHIO

| | | |
|---|---|---|
| In the Matter of the 2018 Long-Term Forecast Report on Behalf of Ohio Power Company and Related Matters | ) ) ) | Case No. 18-501-EL-FOR |
| In the Matter of the Application of Ohio Power Company for Approval To Enter into Renewable Energy Purchase Agreements for Inclusion in The Renewable Generation Rider | ) ) ) ) ) | Case No. 18-1392-EL-RDR |
| In the Matter of the Application of Ohio Power Company for Approval to Amend Its Tariffs | ) ) ) | Case No. 18-1393-EL-ATA |

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# DIRECT TESTIMONY OF KEVIN M. MURRAY
# ON BEHALF OF INDUSTRIAL ENERGY USERS-OHIO

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**JANUARY 2, 2019**

**COUNSEL FOR INDUSTRIAL ENERGY USERS-OHIO**

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## DIRECT TESTIMONY OF KEVIN M. MURRAY ON BEHALF OF INDUSTRIAL ENERGY USERS-OHIO

### I. INTRODUCTION

**Q1. Please state your name and business address.**

A1. My name is Kevin M. Murray. My business address is 21 East State Street, 17th Floor, Columbus, Ohio 43215-4228.

**Q2. By whom are you employed and in what position?**

A2. I am employed as a Technical Specialist by McNees Wallace & Nurick LLC ("McNees") and serve as the Executive Director of the Industrial Energy Users-Ohio ("IEU-Ohio"). I am providing testimony on behalf of IEU-Ohio.

**Q3. Please describe your educational background.**

A3. I graduated from the University of Cincinnati in 1982 with a Bachelor of Science degree in Metallurgical Engineering.

**Q4. Please describe your professional experience.**

A4. I have been employed by McNees for 21 years where I focus on helping IEU-Ohio members address issues that affect the price and availability of utility services. I have also been actively involved, on behalf of commercial and industrial customers, in the formation of regional transmission operators ("RTOs") and the organization of regional electricity markets from both the supply-side and demand-side perspective. I serve as an end-use customer sector representative on the Midcontinent Independent Transmission System Operator, Inc. ("MISO") Advisory Committee and I have been actively involved in MISO working groups that focus on various issues since 1999. Prior to joining McNees, I was employed by the law firm of Kegler, Brown, Hill & Ritter ("KBH&R") in a similar capacity. Prior to joining KBH&R, I spent 12 years with The Timken Company, a specialty steel and roller bearing manufacturer. While at The Timken Company, I worked within a group that focused on meeting the electricity and natural gas requirements for facilities in the United States. I also spent several years in supervisory positions within The Timken Company's steelmaking operations (now TimkenSteel).

**Q5. Have you previously testified before the Public Utilities Commission of Ohio ("Commission")?**

A5. Yes. The proceedings before the Commission in which I have submitted expert testimony are identified in Exhibit KMM-1.

**Q6. What is the purpose of your testimony?**

A6. The purpose of my testimony is to recommend that the Commission find that Ohio Power Company ("AEP Ohio") has not demonstrated a need to own or operate

900 megawatts ("MW") of renewable generation resources including the two solar power purchase agreements.[1] For reasons discussed below, the scope of my testimony is limited to the need issue the Commission has identified as the first-phase or threshold issue. It is my understanding that questions regarding any cost recovery will be addressed, if at all, in a second phase of these proceedings.

## II. HISTORY OF THIS PROCEEDING

**Q7. What is the history of this proceeding?**

A7. On April 16, 2018, AEP Ohio filed its Long-term Forecast Report ("LTFR") for 2018 in Case No. 18-501-EL-FOR. AEP Ohio corrected and supplemented its LTFR on May 31, 2018, and June 26, 2018, at the request of Commission Staff.

On June 7, 2018, AEP Ohio filed a motion for waiver requesting that the Commission waive certain portions of the LTFR requirements for electric utilities and electric transmission owners. In its motion, AEP Ohio stated that it intended to file an amendment to its 2018 LTFR to demonstrate the need for at least 900 megawatts ("MW") of renewable energy projects in Case No. 18-501-EL-FOR, consistent with the Commission's orders in the Company's recent ESP proceedings and its earlier power purchase agreement ("PPA") proceedings. The Commission granted AEP Ohio's waiver request on September 19, 2018, subject to conditions.

On September 19, 2018, AEP Ohio filed an amendment to its 2018 LTFR.

On September 27, 2018, AEP Ohio filed an application in Case No. 18-1392-EL-RDR and Case No. 18-1393-EL-ATA seeking approval to recover, through the AEP Ohio

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[1] In Case No. 16-1852-EL-SSO, *et al.*, the Commission approved AEP Ohio's Renewable Generation Rider as a placeholder to recover the costs associated with up to 900 MW of renewable energy resources, including 400 MW of solar resources and 500 MW of wind resources.

Renewable Generation Rider ("RGR"), the costs associated with two 20-year renewable power purchase agreements ("PPAs").

AEP Ohio also requested that the three cases referenced above be consolidated. The Attorney Examiner issued an Entry granting the request to consolidate these cases on October 22, 2018 and established a procedural schedule including a date for an evidentiary hearing to consider AEP Ohio's application.

As indicated above, the October 22, 2018 Entry also bifurcated these cases into two phases, with the first phase of the proceeding to consider whether AEP Ohio has demonstrated the need for renewable generation resources as required by the Commission's rules. The second phase, if it becomes necessary, will require a separate evidentiary hearing and address AEP Ohio's request to use the RGR to recover the costs associated with the PPAs.

**Q8. How has AEP Ohio characterized the need for its proposed renewable PPAs?**

A8. AEP Ohio has indicated there is a strong desire from its customers to source electricity from renewable energy resources. AEP Ohio's conclusion is based upon a survey conducted on its behalf by Navigant Consulting. AEP Ohio admits that it does not need additional renewable energy for system reliability or the renewable energy credits to comply with Ohio's renewable energy mandates. However, AEP Ohio has interpreted the results of the survey conducted by Navigant Consulting to conclude that AEP Ohio customers desire renewable energy (which AEP Ohio equates to need), even if there are additional costs in securing the renewable resources.

## III. NEEDS FOR CAPACITY

**Q9. Is there a need for additional electrical capacity within the regional power market operated by PJM Interconnection ("PJM")?**

A9. No. The regional power market operated by PJM is awash in capacity and there is no indication this situation is likely to change anytime soon. And, as indicated in the direct written testimony of AEP Ohio witness William Allen in Case no. 18-501-EL-FOR, AEP Ohio is not seeking a Commission determination that there is a need for capacity in this proceeding.

**Q10. Do the results of PJM's most recent base residual auction demonstrate the region does not need additional capacity?**

A10. Yes. The 2021/2022 Reliability Pricing Model ("RPM") Base Residual Auction ("BRA") held in May 2018 cleared 163,627.3 MW of unforced capacity representing a 22.0% reserve margin. After accounting for the use of the current Fixed Resource Requirement ("FRR"), the resulting reserve margin is 21.5% or 5.7% higher than the target minimum reserve market requirement of 15.8%. Although 163,627.3 MW of unforced capacity cleared, a total of 184,585.1 MW of unforced capacity was offered, which demonstrates there is no need for additional capacity in the PJM region. I have attached a report issued by PJM summarizing the results of the May 2018 BRA as Exhibit KMM-2.

**Q11. Is additional capacity planned or under construction in PJM?**

A11. Yes. As of September 30, 2018, there are 101,393.4 MW of capacity in PJM's interconnection queues. Of this, 23,071.3 MW are wind projects and 25,753.4 MW are solar projects. I have attached Section 12 of Monitoring Analytics second quarter

2018 state of the market report as Exhibit KMM-3. This section of the report provides additional detail and statistics on the status of PJM's interconnection queues.

**Q12. Will all of the generation in one of PJM's interconnection queues become commercially operational?**

A12. It is not likely that all of the generation will become commercially operational, based upon historical performance. Since the inception of PJM's interconnection queue and as of September 30, 2018, 59,737.9 MW out of 504,007.2 MW of interconnection requests have resulted in generation projects becoming commercially operational. This history indicates that 11.9% of the generation identified in interconnection queues become commercially operational. If this rate is applied to the 101,393.4 MW currently in an interconnection queue, it implies 12,017.7 MW of new generation will become commercially operational.

**Q13. Is there a need for additional generation physically located in Ohio?**

A13. No. When a generation owner seeks to retire or mothball a generation unit it must submit a deactivation request to PJM. PJM will study the requested retirement and if the retirement would cause reliability concerns, PJM will direct the unit to remain in service until transmission upgrades can be completed. As indicated below, PJM has approved several recent requests to deactivate generation units located in or nearby Ohio which confirms there is no immediate need for in state generation resources.

**Q14. Has PJM considered recent requests to deactivate generation units located in or nearby Ohio?**

A14. Yes. On August 29, 2018, FirstEnergy Solutions submitted a generation deactivation request for Eastlake Unit 6 and Bruce Mansfield Units 1, 2 and 3[2], effective June 1, 2021. FirstEnergy Solutions submitted a deactivation request for Sammis Units 5, 6 and 7 and the Sammis diesel, effective June 1, 2022. PJM approved these deactivation requests on October 11, 2018.

Previously, FirstEnergy Solutions submitted a deactivation request for its Davis Besse, Perry and Beaver Valley Units 1 and 2[3] nuclear facilities with planned retirement dates of May 31, 2020, May 31, 2021, and May 31, 2021 respectively. PJM approved those deactivation requests on May 3, 2018.

**Q15. Notwithstanding the lack of need for additional generation capacity within Ohio, is there new generation capacity being added in Ohio?**

A15. Yes. There are several large natural gas-fired generating facilities located in Ohio that have recently begun commercial operation or are under construction. These include the 799 MW Oregon Clean Energy Center which began commercial operations on July 1, 2017, the 742 MW Carroll County Energy facility which began commercial operations on January 17, 2018, the 525 MW NTE Ohio facility which began commercial operations on May 18, 2018, the 800 MW Clean Energy Future-Lordstown which began commercial operations on September 30, 2018, the 1,650 MW Guernsey Power Station that is being constructed (Ohio Power Siting Board Case No. 16-2443-EL-BGN), the 940 MW Clean Energy Future-Trumbull facility that is being constructed (Ohio Power Siting Board Case No. 16-2444-EL-BGN), the

[2] The Bruce Mansfield Units are located in Shippingport, Pennsylvania, which is physically about 5 miles (as the crow flies) from the Ohio border.

[3] The Beaver Valley facility is also located in Shippingport, Pennsylvania.

955 MW Clean Energy Future-Oregon facility that is being constructed (Ohio Power Siting Board Case No. 17-0530-EL-BGN), and the 1,050 MW Harrison Power Project that is being constructed (Ohio Power Siting Board Case No. 17-1189-EL-BGN). Additionally, as I discuss later in my testimony, there are a large number of renewable energy facilities that have been completed or are under development including several large utility scale solar projects.

**Q16. AEP Ohio has identified two solar projects for which it is seeking Commission approval of PPAs. Does Ohio have a need for additional solar renewable energy credits?**

A16. No. Since the specific in state solar set aside was eliminated by Senate Bill 310 in 2014, solar renewable credits can be sourced from any resource that can be shown to be deliverable to Ohio. The Commission has interpreted this requirement as allowing renewable energy credits to be sourced by any generating facility physically located within PJM.

As I show in Exhibit KMM-4 to my testimony, since it began certifying renewable energy facilities, the Commission has certified 592.47 MW of solar generation.[4] On a combined basis, these facilities have the capability to generate 15,730,818 MWHs of renewable energy credits.[5] As shown on Exhibit KMM-5, this is more than 35.7 times Ohio's 2018 solar renewable mandate.

[4] The data shown on Exhibit KMM-4 was downloaded from the Commission's website and is current as of October 22, 2018 at 9:48 a.m.

[5] 592.47 MW times 35% capacity factor times 8,760 hours equals 1,816,513 MWH. Exhibit KMM-5 is a copy of PJM's business practice manual and related files to establish capacity accreditation for generation resources. PJM accredits non-tracking solar generating facilities at a capacity factor of 38%. Therefore the 35% capacity factor is conservative.

**Q17. Are there additional utility scale solar projects under development in Ohio for which the developers are not asking that customers underwrite the projects' business and financial risk through a non-bypassable charge?**

A17. Yes. As shown on Exhibit KMM-6, in addition to the two solar projects that are included in AEP Ohio's proposal, a total of eight utility scale solar projects having a combined capacity of 914.9 MW have been proposed in Ohio since the beginning of 2017. Hillcrest Solar I, LLC, a planned 125 MW project, has been approved by the Ohio Power Siting Board (OPSB Case No. 17-1152-EL-BGN) and it has received interconnection approval from PJM. The Vinton Solar Farm and Hardin Solar Energy LLC with a combined capacity of 275 MW have been approved by OPSB (OPSB Case Nos. 17-0774-EL-BGN and 17-0773-EL-BGN) and are in the PJM interconnection system study phase. Five additional projects with a combined capacity of 514.9 MW are currently before the Ohio Power Siting Board.

The Hillcrest Solar I, LLC project mentioned above is estimated to generate approximately 383,250 MWH of renewable energy credits each year or more than 7.5 times Ohio's 2018 solar renewable mandate. If all of these facilities are completed, the combined annual energy output would be approximately 2,808,803 MWH, or more than 55 times Ohio's 2018 solar renewable mandate. These facts demonstrate that market forces are working effectively to deliver renewable energy from project developers that are willing and able to assume the business and financial risks associated with those projects, and that there is no need for AEP Ohio proposed renewable PPAs.

## IV. CORPORATE RENEWABLE ENERGY COMMITMENTS

**Q18. AEP Ohio has based its demonstration of need for the proposed renewable energy purchase agreements on the claim that "there is a strong desire on the part of AEP Ohio customers for in-state renewable power." Do you agree that these claimed customer preferences demonstrate a basis for need?**

A18. No. As I have explained, there is no need for these projects based upon system reliability requirements or to meet the state's renewable energy mandates. Further, any customer preferences for renewable energy can be addressed by market forces as I discuss further below.

**Q19. Are corporations establishing voluntary renewable energy commitments?**

A19. Yes. In preparing my testimony I reviewed a report and information publicly posted on the Internet that track voluntary corporate renewable energy commitments. For example, I reviewed a recent report by the International Renewable Energy Agency ("IRENA"), attached to my testimony as Exhibit KMM-7, which indicates that as of 2017 more than 2,400 companies in 75 countries have committed to 465 terawatt hours of renewable energy purchases to further corporate goals such as sustainability.

My review of Internet posted information indicates that, as of the date on which I prepared my testimony, in the United States, 154 companies have joined RE100 and have committed to move to 100% renewable energy purchases over time.[6]

**Q19. Are corporations entering into bilateral contracts to purchase the output of renewable energy facilities?**

[6] A listing of the companies and their commitments is available at: http://there100.org.

A19. Yes. For example, on October 17, 2018, Iron Mountain announced the signing of a 15-year (PPA) with an affiliate of NextEra Energy Resources, LLC, for 145 MWs of new wind energy from the Pretty Prairie Wind Farm, located in Reno County, Kansas.[7] The company has a corporate goal of sourcing 100% of its electricity from renewable energy resources by 2050. It is my understanding that current Ohio law allows customers to competitively source their generation supply requirements and, if they prefer, to rely on renewable generation supply for 100% of such requirements. It is also my understanding that in addition to the market opportunity for customers to source renewable generation through bilateral contracts, they can also support renewable development through a market-based opportunity to purchase renewable energy credits ("RECs").

In fact, and based on a PNM Resources press release, it is my understanding that American Electric Power recently entered into a joint venture with PNM Resources to construct two 50 MW solar generating facilities to supply power to a Facebook data center to be located in New Mexico. I have attached a copy of a press release announcing that joint venture as Exhibit KMM-8.

**Q20. Is American Electric Power or its affiliates actively marketing renewable generation to customers through the use of bilateral contracts?**

A20. Yes. As described in a recent presentation (handout) by American Electric Power at the 53rd Edison Electric Institute ("EEI") Utility Financial Conference, AEP Energy, through its subsidiaries AEP Onsite Partners and AEP Renewables, has provided

[7] A copy of Iron Mountain's press release announcing the transaction is posted at: http://www.ironmountain.com/about-us/news-events/news-categories/press-releases/2018/october/iron-mountain-drives-renewable-energy-goals-for-global-electricity-use-in-2018-through-partnerships-with-nextera-energy-resources (last accessed October 30, 2018).

energy from renewable energy facilities from both utility scale as well as customer-specific “behind the meter” renewable generation facilities in locations throughout the United States. As of October 19, 2018, these projects total 218.4 MW of solar facilities and 257 MW of wind facilities. I have attached a copy of American Electric Power’s EEI presentation as Exhibit KMM-9.

**Q21. What do these renewable energy commitments demonstrate?**

A21. Market-based approaches are working to bring renewable generating resources into the marketplace and are more than adequately addressing customer preferences for renewable energy sources of generation. While AEP Ohio has attempted to suggest the proposed renewable energy projects are needed to meet customer preferences, the large number of projects under development, coupled with significant evidence of corporate demand for renewable energy commitments, demonstrates that market forces are responding and satisfying customer demands for renewable energy and it is not necessary for the Commission to authorize AEP Ohio’s particular proposed solar power purchase agreements or the associated cost recovery through the RGR.

**Q22. This proceeding is the first step to address the need for facilities and whether AEP Ohio customers should bear the risk that the costs of those renewable energy projects exceed market rates. Has AEP Oho demonstrated that customers should bear that risk?**

A22. No. There is no reason to involuntarily conscript AEP Ohio customers to fund AEP Ohio’s purchase from the proposed solar generating facilities. If there is such a strong interest in increased corporate renewable energy purchases as suggested by AEP Ohio in its supporting testimony, it should not be difficult to market the output of the solar facilities through bilateral contracts. Therefore, if AEP Ohio chooses to proceed with the proposed PPAs, it should not be permitted to recover the costs associated with these contracts through a non-bypassable charge applicable to retail customers. There is no need shown that AEP Ohio customers should bear these risks rather than AEP shareholders.

**Q23. Has the Commission directed AEP Ohio to consider the use of bilateral contracts in order to fulfill the renewable energy commitment that AEP Ohio entered into through the stipulation and recommendation submitted in Case No. 14-1693-EL-RDR to resolve the proceeding?**

A23. Yes. In its March 31, 2016 Opinion and Order accepting the stipulation and recommendation to resolve Case No. 14-1693-EL-RDR, the Commission directed AEP Ohio to first look towards the use of bilateral contracting opportunities in order to fulfill the 900 MW renewable commitment of AEP Ohio:

> The Commission first encourages that bilateral contracting opportunities be explored to provide support for the construction of renewables. To the extent that bilateral opportunities are not available, the Commission will entertain and review a cost recovery filing, first focusing on enhancing solar opportunities. We also direct AEP Ohio to demonstrate that bilateral opportunities were explored and that a competitive process was utilized to source and determine ownership of any project to be built.

*In the Matter of the Application Seeking Approval of Ohio Power Company's Proposal to Enter into an Affiliate Power Purchase Agreement for Inclusion in the Power Purchase Agreement Rider,* Case No. 14-1693-El-RDR, Opinion and Order at 83 (March 31, 2016).

**Q24. Has AEP Ohio presented evidence that it has pursued the use of bilateral contracts to fulfill its renewable energy commitments?**

A24. No. There is nothing in AEP Ohio's testimony that discusses a structure that involves a bypassable charge or bilateral retail contracts.

## V. CONCLUSION

**Q25. What are your conclusions and recommendations?**

A25. The Commission should conclude that AEP Ohio's proposed definition of need (a claimed customer preference for renewable energy facilities) does not satisfy the Commission's long-term forecast rules to demonstrate the need for additional electricity resource options. Further, the Commission should conclude that AEP Ohio has failed to demonstrate the need for its proposed solar PPAs. After reaching that conclusion, the Commission should rule the second phase of this proceeding is not necessary and dismiss AEP Ohio's request to collect costs associated with the power purchase agreements through Rider RGR as moot.

**Q26. Does this conclude your direct testimony?**

A26. Yes.

**Exhibit KMM-1**

## Exhibit KMM-1

*In the Matter of the Application of Ohio Power Company for Authority to Establish a Standard Service Offer Pursuant to §4928.143, Revised Code, in the Form of an Electric Security Plan, et al.,* Case Nos. 13-2385-EL-SSO, *et al.*

*In the Matter of the Application of The Dayton Power and Light Company for Approval of Its Market Rate Offer*, *et al.,* PUCO Case Nos. 12-426-EL-SSO, *et al.*

*In the Matter of the Commission Review of the Capacity Charges of Ohio Power Company and Columbus Southern Power Company,* PUCO Case No. 10-2929-EL-UNC.

*In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Authority to Establish a Standard Service Offer Pursuant to §4928.143, Ohio Rev. Code, in the Form of an Electric Security Plan*, PUCO Case Nos. 11-346-EL-SSO and 11-348-EL-SSO, *et al.*

*In the Matter of the Application of Columbus Southern Power Company for Approval of its Electric Security Plan; an Amendment to its Corporate Separation Plan, and the Sale or Transfer of Certain Generating Assets*, Case No. 08-917-EL-SSO and *In the Matter of the Application of Ohio Power Company for Approval of its Electric Security Plan; and an Amendment to its Corporate Separation Plan*, PUCO Case No. 08-918-EL-SSO (remand phase).

*In the Matter of the Application of Columbus Southern Power Company for Approval of its Program Portfolio Plan and Request for Expedited Consideration*, PUCO Case No. 09-1089-EL-POR.

*In the Matter of the Application of Ohio Power Company for Approval of its Program Portfolio Plan and Request for Expedited Consideration*, PUCO Case No. 09-1090-EL-POR.

*In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company for Approval of a Market Rate Offer to Conduct a Competitive Bidding Process for Standard Service Offer Electric Generation Supply, Accounting Modifications Associated with Reconciliation Mechanism, and Tariffs for Generation Service*, PUCO Case No. 09-906-EL-SSO.

*In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company for Authority to Establish a Standard Service Offer Pursuant to R.C. 4928.143 in the Form of an Electric Security Plan*, PUCO Case No. 08-935-EL-SSO.

*In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company for Approval of a Market Rate Offer to Conduct a Competitive Bidding Process for Standard Service Offer Electric Generation Supply,* *Accounting Modifications Associated with Reconciliation Mechanism, and Tariffs for Generation Service*, PUCO Case No. 08-936-EL-SSO.

*In the Matter of the Application of Columbus Southern Power Company for Approval of its Electric Security Plan; an Amendment to its Corporate Separation Plan; and the Sale or Transfer of Certain Generating Assets*, PUCO Case No. 08-917-EL-SSO.

*In the Matter of the Application of Ohio Power Company for Approval of its Electric Security Plan; and an Amendment to its Corporate Separation Plan*, PUCO Case No. 08-918-EL-SSO.

*In the Matter of the Application of Duke Energy Ohio for Approval of an Electric Security Plan*, PUCO Case No. 08-920-EL-SSO.

*In the Matter of the Application of The Dayton Power and Light Company for Approval of Its Electric Security Plan*, PUCO Case No. 08-1094-EL-SSO.

# EXHIBIT KMM-2

# 2021/2022 RPM Base Residual Auction Results

## Executive Summary

The 2021/2022 Reliability Pricing Model (RPM) Base Residual Auction (BRA) cleared 163,627.3 MW of unforced capacity in the RTO representing a 22.0% reserve margin. Accounting for load and resource commitments under the Fixed Resource Requirement (FRR), the reserve margin for the entire RTO for the 2021/2022 Delivery Year as procured in the BRA is 21.5%, or 5.7% higher than the target reserve margin of 15.8%. This reserve margin was achieved at clearing prices that are between approximately 44% to 82% of Net CONE, depending upon the Locational Deliverability Area (LDA). The auction also attracted a diverse set of resources, including a significant increase in Demand Response and Energy Efficiency resources, additional wind and solar resources, and one new combined cycle gas resource.

The 2021/2022 BRA is the second where PJM has procured 100% Capacity Performance ("CP") Resources. CP Resources must be capable of sustained, predictable operation, and are expected to be available and capable of providing energy and reserves when needed throughout the entire Delivery Year. As was the case with the 2020/2021 BRA, the 2021/2022 BRA was conducted under the provisions of PJM's Enhanced Aggregation filing (Docket ER17-367-000 & 001) which was accepted by FERC on March 21, 2017.

### 2021/2022 BRA Resource Clearing Prices

Resource Clearing Prices (RCPs) for the 2021/2022 BRA are shown in Table 1 below. The RCP for CP Resources located in the rest of RTO is $140.00/MW-day. EMAAC, PSEG, BGE, ATSI and COMED were constrained LDAs in the 2021/2022 BRA with locational price adders, in regards to the immediate parent LDA, of $25.73/MW-day, $38.56/MW-day, $60.30/MW-day, $31.33/MW-day and $55.55/MW-day, respectively, for all resources located in those LDAs. For comparison, the RTO's resource clearing price in the 2020/2021 BRA was $76.53/MW-day. Additionally, the MAAC, EMAAC, COMED and DEOK LDA were constrained LDAs in the 2020/2021 BRA with RCPs of $86.04/MW-day, $187.87/MW-day, $188.12/MW-day and $130.00/MW-day respectively.

| | 2021/22 BRA Resource Clearing Prices ($/MW-day) | | | | | |
|---|---|---|---|---|---|---|
| Capacity Type | Rest of RTO | EMAAC | PSEG | BGE | ATSI | COMED |
| Capacity Performance | $140.00 | $165.73 | $204.29 | $200.30 | $171.33 | $195.55 |

# 2021/2022 RPM Base Residual Auction Results

**2021/2022 BRA Cleared Capacity Resources**

As seen in the table below, the 2021/2022 BRA procured 893.0 MW of capacity from new generation and 508.3 MW from uprates to existing or planned generation. The quantity of capacity procured from external Generation Capacity Resources in the 2021/2022 BRA is 4,051.8 MW which is an increase of 54.6 MW from that procured in last year's BRA. All external generation capacity that has cleared in the 2021/2022 BRA are Prior Capacity Import Limit (CIL) Exception External Resources[1] that qualify for an exception for the 2021/2022 Delivery Year to satisfy the enhanced pseudo-tie requirements established by FERC Order ER17-1138. The total quantity of DR procured in the 2021/2022 BRA is 11,125.8 MW which is an increase of 3,305.4 MW from that procured in last year's BRA; and, the total quantity of EE procured in the 2021/2022 BRA is 2,832.0 MW, which is an increase of 1,121.8 MW from that procured in last year's BRA.

**Megawatts of Unforced Capacity Procured by Type from the 2014/2015 BRA to the 2021/2022 BRA**

| BRA Delivery Year | New Generation | Generation Uprates | Imports | Demand Response | Energy Efficiency |
|---|---|---|---|---|---|
| 2021/2022 | 893.0 | 508.3 | 4,051.8 | 11,125.8 | 2,832.0 |
| 2020/2021 | 2,389.3 | 434.5 | 3,997.2 | 7,820.4 | 1,710.2 |
| 2019/2020 | 5,373.6 | 155.6 | 3,875.9 | 10,348.0 | 1,515.1 |
| 2018/2019 | 2,954.3 | 587.6 | 4,687.9 | 11,084.4 | 1,246.5 |
| 2017/2018 | 5,927.4 | 339.9 | 4,525.5 | 10,974.8 | 1,338.9 |
| 2016/2017 | 4,281.6 | 1,181.3 | 7,482.7 | 12,408.1 | 1,117.3 |
| 2015/2016 | 4,898.9 | 447.4 | 3,935.3 | 14,832.8 | 922.5 |
| 2014/2015 | 415.5 | 341.1 | 3,016.5 | 14,118.4 | 822.1 |

*All MW Values are in UCAP Terms

[1] A Prior CIL Exception Resource is an external Generation Capacity Resource for which (1) a Capacity Market Seller had, prior to May 9, 2017, cleared a Sell Offer in an RPM Auction under the exception provided to the definition of Capacity Import Limit as set forth in Article 1 of the Reliability Assurance Agreement or (2) an FRR Entity committed, prior to May 9, 2017, in an FRR Capacity Plan under the exception provided to the definition of Capacity Import Limit.

# 2021/2022 RPM Base Residual Auction Results

## Introduction

This document provides information for PJM stakeholders regarding the results of the 2021/2022 Reliability Pricing Model (RPM) Base Residual Auction (BRA). The 2021/2022 BRA opened on May 10, 2018, and the results were posted on May 23, 2018.

In each BRA, PJM seeks to procure a target capacity reserve level for the RTO in a least cost manner while recognizing the following reliability-based constraints on the location and type of capacity that can be committed:

- Internal PJM locational constraints are established by setting up Locational Deliverability Areas (LDAs) with each LDA having a separate target capacity reserve level and a maximum limit on the amount of capacity that it can import from resources located outside of the LDA.
- Total cleared summer-period sell offers must exactly equal total cleared winter-period sell offers across the entire RTO to ensure that seasonal CP sell offers clear to form annual CP commitments.

The auction clearing process commits capacity resources to procure a target capacity reserve level for the RTO in a least-cost manner while recognizing and enforcing these reliability-based constraints. The clearing solution may be required to commit capacity resources out-of-merit order but again in a least-cost manner to ensure that all of these constraints are respected. In those cases where one or more of the constraints results in out-of-merit commitment in the auction solution, resource clearing prices will be reflective of the price of resources selected out of merit order to meet the necessary requirements.

This document begins with a high-level summary of the BRA results followed by sections containing detailed descriptions of the 2021/2022 BRA results and a discussion of the results in the context of the previous BRAs.

## Summary of Results

The 2021/2022 Reliability Pricing Model (RPM) Base Residual Auction (BRA) cleared 163,627.3 MW of unforced capacity in the RTO representing a 22.0% reserve margin. The reserve margin for the entire RTO is 21.5%, or 5.7% higher than the target reserve margin of 15.8%, when the Fixed Resource Requirement (FRR) load and resources are considered.

Resource Clearing Prices (RCPs) for the 2021/2022 BRA are shown in Table 1 below. EMAAC, PSEG, BGE, ATSI and COMED were constrained LDAs in the 2021/2022 BRA with locational price adders, in regards to the immediate parent LDA, of $25.73/MW-day, $38.56/MW-day, $60.30/MW-day, $31.33/MW-day and $55.55/MW-day, respectively, for all resources located in those LDAs. For comparison, the RTO's resource clearing price in the 2020/2021 BRA was $76.53/MW-day. Additionally, the MAAC, EMAAC, COMED and DEOK LDA were constrained LDAs in the 2020/2021 BRA with RCPs of $86.04/MW-day, $187.87/MW-day, $188.12/MW-day and $130.00/MW-day respectively.

The total Unforced Capacity (UCAP) of Generation Capacity Resources offered into this auction but not previously offered into a prior auction was 1,098.5 MW comprised of 322.2 MW of new generation units and 776.3 MW of uprates to existing or planned generation units. The quantity of new Generation Capacity Resources cleared regardless of whether they had offered into a prior auction was 1,401.3 MW comprised of 893.0 MW from new generation units and 508.3 MW from uprates to existing or planned generation units.

The quantity of Unforced Capacity procured from external Generation Capacity Resources in the 2021/2022 BRA is 4,051.8 MW which is an increase of 54.6 MW from that procured in last year's BRA. All external generation capacity that has cleared in the 2021/2022 BRA are Prior Capacity Import Limit (CIL) Exception External Resources that qualify for an exception for the 2021/2022 Delivery Year to satisfy the enhanced pseudo-tie requirements established by FERC Order ER17-1138.

The total Unforced Capacity of DR procured in the 2021/2022 BRA is 11,125.8 MW which is an increase of 3,305.4 MW from that procured in last year's BRA; and, the total quantity of EE procured in the 2021/2022 BRA is 2,832.0 MW which is an increase of 1,121.8 MW from that procured in last year's BRA.

The RTO as a whole failed the Market Structure Test (i.e., the Three-Pivotal Supplier Test), resulting in the application of market power mitigation to all existing generation resources. Mitigation was applied to a supplier's existing generation resources resulting in utilizing the lesser of the supplier's approved Market Seller Offer Cap for such resource or the supplier's submitted offer price for such resource in the RPM Auction clearing.

On December 8, 2017, the Federal Energy Regulatory Commission issued a Remand Order rejecting PJM's Minimum Offer Price Rule ("MOPR") proposal in Docket No. ER13-535. As a result of the remand order all RPM Auctions conducted as of December 8, 2017, will be done so under the MOPR rules that were in effect just prior to PJM's December 7, 2012 MOPR filing. Most significantly, the competitive-entry and self-supply exemption mechanisms become immediately invalid on a prospective basis and the unit-specific exception request mechanism becomes the only means by which a sell offer of certain resource types may be submitted at a price below the MOPR Floor Offer Price. Furthermore, MOPR is applicable to the sell offer of any Generation Capacity Resource, including an uprate, regardless of the size, that has not previously cleared in an RPM Auction and is located in an LDA for which a separate VRR Curve was established for use in the BRA of the relevant delivery year, and that the unit is not a nuclear, coal, IGCC, hydroelectric, wind or solar facilities. Additionally, any External Generation Capacity Resources meeting the above criteria and that have entered commercial operation on or after January 1, 2013 and that require sufficient transmission investment for delivery into PJM are also subject to MOPR. To avoid application of the MOPR, Capacity Market Sellers may request a unit-specific exception.

A further discussion of the 2021/2022 BRA results and additional information regarding the 2021/2022 RPM BRA are detailed in the body of this report. The discussion also provides a comparison of the 2021/2022 auction results to the results from the 2007/2008 through 2020/2021 RPM Auctions.

## 2021/2022 RPM Base Residual Auction Results

### 2021/2022 Base Residual Auction Results Discussion

Table 1 contains a summary of the RTO clearing prices, cleared unforced capacity, and implied cleared reserve margins resulting from the 2021/2022 RPM BRA in comparison to those from 2007/2008 through 2020/2021 RPM BRAs.

**Table 1 –RPM Base Residual Auction Resource Clearing Price Results in the RTO**

| | Auction Results | | |
|---|---|---|---|
| Delivery Year | Resource Clearing Price | Cleared UCAP (MW) | Reserve Margin |
| 2007/2008 | $ 40.80 | 129,409.2 | 19.1% |
| 2008/2009 | $ 111.92 | 129,597.6 | 17.4% |
| 2009/2010 | $ 102.04 | 132,231.8 | 17.6% |
| 2010/2011 | $ 174.29 | 132,190.4 | 16.4% |
| 2011/2012[1] | $ 110.00 | 132,221.5 | 17.9% |
| 2012/2013 | $ 16.46 | 136,143.5 | 20.5% |
| 2013/2014[2] | $ 27.73 | 152,743.3 | 19.7% |
| 2014/2015[3] | $ 125.99 | 149,974.7 | 18.8% |
| 2015/2016[4] | $ 136.00 | 164,561.2 | 19.3% |
| 2016/2017[5] | $ 59.37 | 169,159.7 | 20.3% |
| 2017/2018 | $ 120.00 | 167,003.7 | 19.7% |
| 2018/2019 | $ 164.77 | 166,836.9 | 19.8% |
| 2019/2020 | $ 100.00 | 167,305.9 | 22.4% |
| 2020/2021[6] | $ 76.53 | 165,109.2 | 23.3% |
| 2021/2022 | $ 140.00 | 163,627.3 | 21.5% |

1) 2011/2012 BRA w as conducted w ithout Duquesne zone load.
2) 2013/2014 BRA includes ATSI zone
3) 2014/2015 BRA includes Duke zone
4) 2015/2016 BRA includes a significant portion of AEP and DEOK zone load previously under the FRR Alternative
5) 2016/2017 BRA includes EKPC zone
6) Beginning 2020/2021 Cleared UCAP (MW) includes Annual and matched Seasonal Capacity Performance sell offers

The Reserve Margin presented in Table 1 represents the percentage of installed capacity cleared in RPM and committed by FRR entities in excess of the RTO load (including load served under the Fixed Resource Requirement alternative). The 2021/2022 RPM

# 2021/2022 RPM Base Residual Auction Results

BRA cleared 163,627.3 MW of unforced capacity in the RTO representing a 22% reserve margin. The reserve margin for the entire RTO is 21.5%, or 5.7% higher than the target reserve margin of 15.8%, when the Fixed Resource Requirement (FRR) load and resources are considered.

**New Generation Resource Participation**

The total Unforced Capacity of new Generation Capacity Resources offered into the auction that had not offered into a prior auction was 1,098.5 MW comprised of 322.2 MW of new generation units and 776.3 MW of uprates to existing or planned generation units. The quantity of new Generation Capacity Resources cleared in this auction regardless of whether they had offered into a prior auction was 1,401.3 MW comprised of 893.0 MW from new generation units, and 508.3 MW from uprates to existing or planned generation units.

Table 2A shows the breakdown, by major LDA, of capacity in UCAP terms of new units and uprates at existing or planned units offered in the auction and capacity actually clearing in the auction. Eighty one percent of the new generation capacity that offered into the 2021/2022 BRA cleared the auction; an additional 511.8 MW of new generation capacity cleared for the first time that had previously offered into a BRA.

**Table 2A – Offered and Cleared New Generation Capacity by LDA (in UCAP MW)**

| | Offered | | | Cleared | | |
|---|---|---|---|---|---|---|
| LDA | Uprate | New Unit | Total | Uprate | New Unit | Total |
| EMAAC | 84.4 | 9.6 | **94.0** | 29.3 | 9.6 | **38.9** |
| MAAC** | 271.8 | 40.8 | **312.6** | 105.9 | 22.1 | **128.0** |
| Total RTO | 776.3 | 322.2 | **1,098.5** | 508.3 | 893.0 | **1,401.3** |

*All MW Values are in UCAP Terms

**MAAC includes EMAAC

***RTO includes MAAC

**** Cleared MW values may include new units that have offered in a prior BRA and not cleared

## 2021/2022 RPM Base Residual Auction Results

### Capacity Import Participation

The quantity of capacity imports cleared in the 2021/2022 BRA were 4,051.8 MW (UCAP) which represents an increase of 54.6 MW from the imports that cleared in the 2020/2021 BRA. The majority of the imports are from resources located in regions west of the PJM RTO. All external generation capacity that has cleared in the 2021/22 BRA are Prior Capacity Import Limit (CIL) Exception External Resources that qualify for an exception for the 2021/2022 Delivery Year to satisfy the enhanced pseudo-tie requirements established by FERC Order ER17-1138.

### Table 2B – Offered and Cleared Capacity Imports (in UCAP MW)

| | External Source Zones | | | | | |
|---|---|---|---|---|---|---|
| | NORTH | WEST 1 | WEST 2 | SOUTH 1 | SOUTH 2 | Total |
| Offered MW (UCAP) | 252.6 | 1,255.4 | 2,173.4 | 531.8 | 257.2 | 4,470.4 |
| Cleared MW (UCAP) | 252.6 | 1,251.3 | 1,774.9 | 515.8 | 257.2 | 4,051.8 |

* Offered and Cleared MW quantities include resources that received CIL Exception and those associated with pre-OATT grandfathered transmission. Attachment G of Manual 14B provides a mapping of outside Balancing Authorities to the External Source Zones.

### Demand Resource Participation

The total Unforced Capacity of DR offered into the 2021/2022 BRA was 11,886.8 MW, representing an increase of 20.7% from the DR that offered into the 2020/2021 BRA. Of the 11,886.8 MW of total DR that offered in this auction, 11,125.8 MW cleared. The cleared DR is 3,305.4 MW greater than that which cleared in the 2020/2021 BRA. Of the 11,125.8 MW of DR cleared in the 2021/2022 BRA, 10,673.5 MW were cleared as the annual Capacity Performance Product and 452.3 MW were cleared as the summer seasonal Capacity Performance product. Table 3A contains a comparison of the DR offered and cleared in 2020/2021 BRA & 2021/2022 BRA represented in UCAP.

### Energy Efficiency Resource Participation

An EE resource is a project that involves the installation of more efficient devices/equipment or the implementation of more efficient processes/systems exceeding then-current building codes, appliance standards, or other relevant standards at the time of installation as known at the time of commitment. The EE resource must achieve a permanent, continuous reduction in electric energy consumption (during the defined EE performance hours) that is not reflected in the peak load forecast used for the BRA for the Delivery Year for which the EE resource is proposed. The EE resource must be fully implemented at all times during the Delivery Year, without any requirement of notice, dispatch, or operator intervention. Of the 2,954.8 MW of energy efficiency that offered into the 2021/2022

BRA, 2,832.0 MW cleared in the auction. Of the 2,832.0 MW of EE Resources cleared in the 2021/2022 BRA, 2,622.7 MW was cleared as the annual Capacity Performance Product and 209.3 MW were cleared as the summer seasonal Capacity Performance product.

Table 3B contains a summary of the DR and EE resources that offered and cleared by zone in the 2021/2022 BRA. Approximately 93.6% of the DR and 95.8% of the EE resources that were offered into the BRA cleared.

Figure 1 illustrates the demand side participation in the PJM Capacity Market from 2005/2006 Delivery Year to the 2021/2022 Delivery Year. Demand side participation includes active load management (ALM) prior to 2007/2008 Delivery Year, Interruptible Load for Reliability (ILR) and DR offered into each BRA and nominated in FRR Plans, and EE resources starting with the 2012/2013 Delivery Year. The demand side participation in the capacity market has increased dramatically since the inception of RPM in the 2007/2008 Delivery Year through the 2015/2016 BRA, but as shown in Figure 1, total demand side participation and cleared resources for the 2021/2022 BRA have fallen below the levels seen in the 2014/2015 BRA.

## 2021/2022 RPM Base Residual Auction Results

### Table 3A – Comparison of Demand Resources Offered and Cleared in 2020/2021 BRA & 2021/2022 BRA (in UCAP MW)

| | | Offered MW (UCAP) | | | Cleared MW (UCAP) | | |
|---|---|---|---|---|---|---|---|
| LDA | Zone | 2020/2021* | 2021/2022* | Increase in Offered MW | 2020/2021* | 2021/2022* | Increase in Cleared MW |
| EMAAC | AECO | 72.5 | 83.6 | 11.1 | 62.8 | 83.4 | 20.6 |
| EMAAC/DPL-S | DPL | 330.0 | 320.3 | (9.7) | 213.4 | 265.1 | 51.7 |
| EMAAC | JCPL | 160.1 | 173.0 | 12.9 | 143.9 | 170.3 | 26.4 |
| EMAAC | PECO | 408.3 | 450.9 | 42.6 | 363.3 | 446.4 | 83.1 |
| PSEG/PS-N | PSEG | 353.5 | 423.3 | 69.8 | 327.7 | 407.9 | 80.2 |
| EMAAC | RECO | 3.8 | 6.0 | 2.2 | 3.7 | 5.8 | 2.1 |
| **EMAAC Sub Total** | | **1,328.2** | **1,457.1** | **128.9** | **1,114.8** | **1,378.9** | **264.1** |
| PEPCO | PEPCO | 346.7 | 452.5 | 105.8 | 211.9 | 345.9 | 134.0 |
| BGE | BGE | 430.5 | 369.4 | (61.1) | 246.5 | 279.0 | 32.5 |
| MAAC | METED | 294.0 | 367.5 | 73.5 | 241.8 | 360.4 | 118.6 |
| MAAC | PENELEC | 356.6 | 373.5 | 16.9 | 304.1 | 364.5 | 60.4 |
| PPL | PPL | 693.5 | 744.5 | 51.0 | 579.9 | 684.7 | 104.8 |
| **MAAC** Sub Total** | | **3,449.5** | **3,764.5** | **315.0** | **2,699.0** | **3,413.4** | **714.4** |
| RTO | AEP | 1,408.5 | 1,829.2 | 420.7 | 1,010.5 | 1,680.4 | 669.9 |
| RTO | APS | 933.2 | 1,049.7 | 116.5 | 709.8 | 1,019.4 | 309.6 |
| ATSI/ATSI-C | ATSI | 815.8 | 1,221.2 | 405.4 | 688.7 | 1,142.4 | 453.7 |
| COMED | COMED | 1,794.4 | 2,078.2 | 283.8 | 1,512.9 | 1,997.8 | 484.9 |
| DAY | DAY | 212.4 | 235.0 | 22.6 | 164.6 | 227.7 | 63.1 |
| DEOK | DEOK | 200.8 | 235.6 | 34.8 | 152.8 | 213.8 | 61.0 |
| RTO | DOM | 700.2 | 1,173.4 | 473.2 | 585.3 | 1,136.1 | 550.8 |
| RTO | DUQ | 192.6 | 140.6 | (52.0) | 159.9 | 135.4 | (24.5) |
| RTO | EKPC | 139.3 | 159.4 | 20.1 | 136.9 | 159.4 | 22.5 |
| **Grand Total** | | **9,846.7** | **11,886.8** | **2,040.1** | **7,820.4** | **11,125.8** | **3,305.4** |

* MW values include both Annual and Summer-Period Capacity Performance DR

** MAAC sub-total includes all MAAC Zones

## 2021/2022 RPM Base Residual Auction Results

**Table 3B – Comparison of Demand Resources and Energy Efficiency Resources Offered and Cleared in the 2021/2022 BRA (in UCAP MW)**

| | | Offered MW (UCAP)* | | | Cleared MW (UCAP)* | | |
|---|---|---|---|---|---|---|---|
| LDA | Zone | DR | EE | Total | DR | EE | Total |
| EMAAC | AECO | 83.6 | 45.4 | 129.0 | 83.4 | 42.4 | 125.8 |
| EMAAC/DPL-S | DPL | 320.3 | 50.4 | 370.7 | 265.1 | 48.0 | 313.1 |
| EMAAC | JCPL | 173.0 | 179.9 | 352.9 | 170.3 | 178.0 | 348.3 |
| EMAAC | PECO | 450.9 | 105.1 | 556.0 | 446.4 | 100.6 | 547.0 |
| PSEG/PS-N | PSEG | 423.3 | 259.2 | 682.5 | 407.9 | 240.1 | 648.0 |
| EMAAC | RECO | 6.0 | 8.4 | 14.4 | 5.8 | 7.9 | 13.7 |
| EMAAC Sub Total | | 1,457.1 | 648.4 | 2,105.5 | 1,378.9 | 617.0 | 1,995.9 |
| PEPCO | PEPCO | 452.5 | 108.3 | 560.8 | 345.9 | 102.6 | 448.5 |
| BGE | BGE | 369.4 | 105.0 | 474.4 | 279.0 | 104.4 | 383.4 |
| MAAC | METED | 367.5 | 26.1 | 393.6 | 360.4 | 23.0 | 383.4 |
| MAAC | PENELEC | 373.5 | 22.5 | 396.0 | 364.5 | 19.3 | 383.8 |
| PPL | PPL | 744.5 | 81.3 | 825.8 | 684.7 | 72.4 | 757.1 |
| MAAC** Sub Total | | 3,764.5 | 991.6 | 4,756.1 | 3,413.4 | 938.7 | 4,352.1 |
| RTO | AEP | 1,829.2 | 199.2 | 2,028.4 | 1,680.4 | 177.8 | 1,858.2 |
| RTO | APS | 1,049.7 | 60.0 | 1,109.7 | 1,019.4 | 56.4 | 1,075.8 |
| ATSI/ATSI-C | ATSI | 1,221.2 | 153.3 | 1,374.5 | 1,142.4 | 148.2 | 1,290.6 |
| COMED | COMED | 2,078.2 | 787.6 | 2,865.8 | 1,997.8 | 770.5 | 2,768.3 |
| DAY | DAY | 235.0 | 75.5 | 310.5 | 227.7 | 60.1 | 287.8 |
| DEOK | DEOK | 235.6 | 90.7 | 326.3 | 213.8 | 89.7 | 303.5 |
| RTO | DOM | 1,173.4 | 564.3 | 1,737.7 | 1,136.1 | 561.1 | 1,697.2 |
| RTO | DUQ | 140.6 | 32.6 | 173.2 | 135.4 | 29.5 | 164.9 |
| RTO | EKPC | 159.4 | - | 159.4 | 159.4 | - | 159.4 |
| Grand Total | | 11,886.8 | 2,954.8 | 14,841.6 | 11,125.8 | 2,832.0 | 13,957.8 |

* MW values include both Annual and Summer-Period Capacity Performance DR and EE

** MAAC sub-total includes all MAAC Zones

## 2021/2022 RPM Base Residual Auction Results

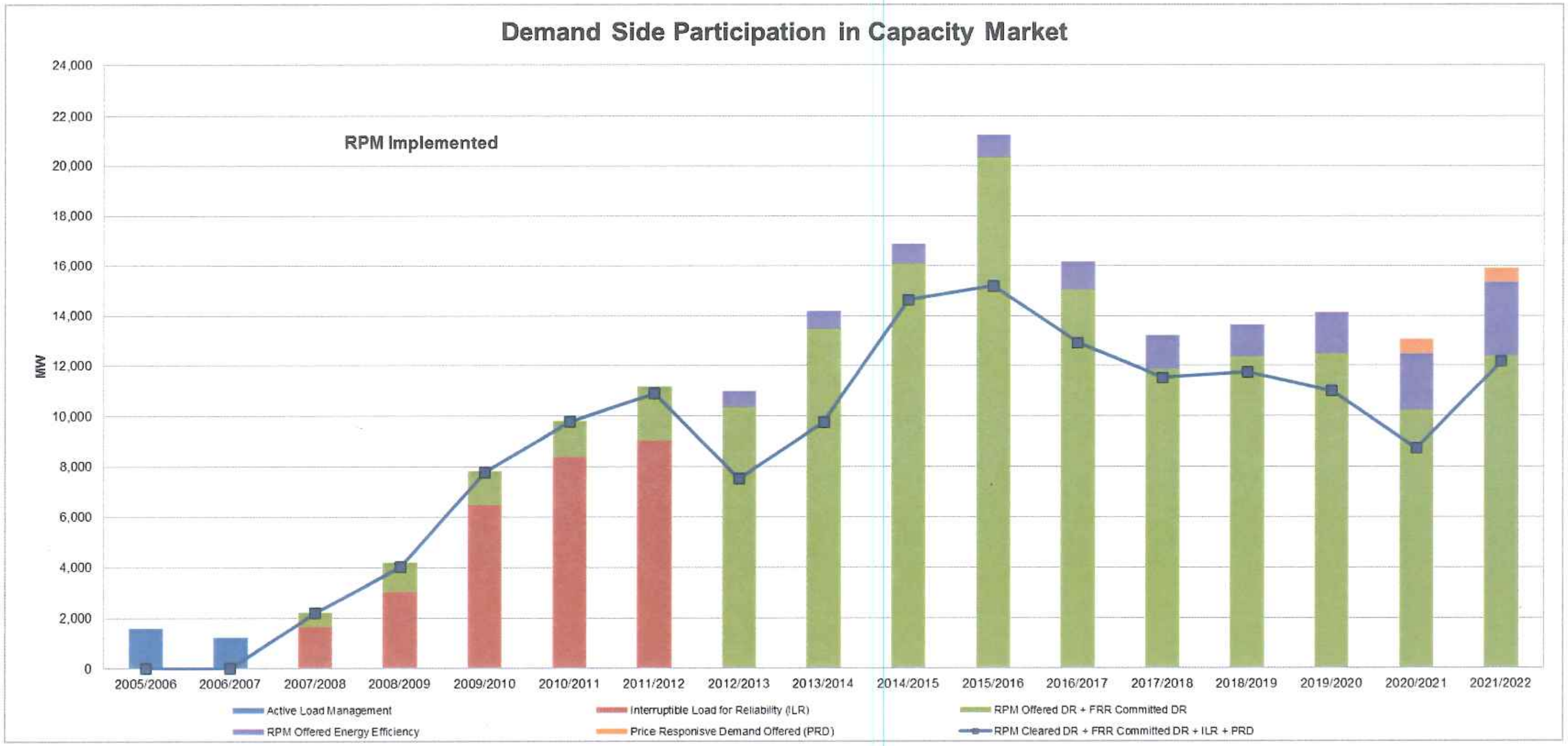
**Table 3C – Breakdown of Annual and Seasonal Capacity Performance Resources by Resource Type and Season that Offered and Cleared in the 2021/2022 BRA (in UCAP MW)**

| | Offered MW (UCAP) | | | Cleared MW (UCAP) | | |
|---|---|---|---|---|---|---|
| Resource Type | Annual Capacity Performance | Summer Capacity Performance | Winter Capacity Performance | Annual Capacity Performance | Summer Capacity Performance | Winter Capacity Performance |
| GEN | 170,841.5 | 106.2 | 715.5 | 149,615.6 | 53.9 | 715.5 |
| DR | 11,094.6 | 792.2 | - | 10,673.5 | 452.3 | - |
| EE | 2,649.0 | 305.8 | - | 2,622.7 | 209.3 | - |
| **Grand Total** | **184,585.1** | **1,204.2** | **715.5** | **162,911.8** | **715.5** | **715.5** |



PJM #5154776

**Figure 1 – Demand Side Participation in the PJM Capacity Market**




### Renewable Resource Participation

1,416.7 MW of wind resources cleared the 2021/2022 BRA as compared to 887.7 MW of wind resources that cleared the 2020/2021 BRA. Of the 1,416.7 MW of wind resources cleared in the 2021/2022 BRA, 710.2 MW were cleared as the annual Capacity Performance Product and 706.5 MW were cleared as the winter seasonal Capacity Performance product. The nameplate capability of wind resources that cleared in the 2021/2022 BRA as annual CP capacity and/or winter seasonal CP capacity is approximately 8,126 MW, which is 1,407 MW greater than the 6,719 MW of wind energy nameplate capability that cleared in last year's auction.

569.9 MW of solar resources cleared the 2021/2022 BRA as compared to 125.3 MW of solar resources that cleared the 2020/2021 BRA. Of the 569.9 MW of solar resources cleared in the 2021/2022 BRA, 516.0 MW were cleared as the annual Capacity Performance Product and 53.9 MW were cleared as the summer seasonal Capacity Performance product. The nameplate capability of solar resources that cleared in the 2021/2022 BRA as annual CP capacity and/or summer seasonal CP capacity is approximately 1,641 MW, which is 964 MW greater than the 677 MW of solar energy nameplate capability that cleared in last year's auction.

**Price Responsive Demand Participation**

A total Nominal PRD Value of 510 MW was elected and committed in the 2021/2022 BRA. PRD is provided by a PJM Member that represents retail customers having the ability to predictably reduce consumption in response to changing wholesale prices. In the PJM Capacity Market, a PRD Provider may voluntarily make a firm commitment of the quantity of PRD that will reduce its consumption in response to real time energy price during a Delivery Year. A PRD Provider that is committing PRD in a BRA must also submit a PRD election in the eRPM system which indicates the Nominal PRD Value in MWs that the PRD Provider is willing to commit at different reservation prices ($/MW-day). The VRR curve of the RTO and each affected LDA is shifted leftward along the horizontal axis by the UCAP MW quantity of elected PRD where the leftward shift occurs only for the portion of the VRR Curve at or above the PRD Reservation price. As shown in the 2021/2022 Planning Parameters, 510 MW of PRD across the RTO has elected to participate in the 2021/2022 BRA: 240 MW in the BGE LDA, 195 MW in the PEPCO LDA, and 75 MW in the EMAAC LDA (with 35.7 MW located in the DPL-South LDA). The VRR Curve of the RTO and each affected LDA is shifted leftward along the horizontal axis by the UCAP MW value of these quantities at the PRD Reservation Price. Once committed in a BRA, a PRD commitment cannot be replaced; the commitment can only be satisfied through the registration of price response load in the DR Hub system prior to or during the Delivery Year.

**LDA Results**

An LDA was modeled in the BRA and had a separate VRR Curve if (1) the LDA has a CETO/CETL margin that is less than 115%; or (2) the LDA had a locational price adder in any of the three immediately preceding BRAs; or (3) the LDA is EMAAC, SWMAAC, and MAAC. An LDA not otherwise qualifying under the above three tests may also be modeled if PJM finds that the LDA is determined to be likely to have a Locational Price Adder based on historic offer price levels or if such LDA is required to achieve an acceptable level of reliability consistent with the Reliability Principles and Standards.

As a result of the above criteria, MAAC, EMAAC, SWMAAC, PSEG, PS-NORTH, DPL-SOUTH, PEPCO, ATSI, ATSI-Cleveland, COMED, BGE, PL, DAY and DEOK were modeled as LDAs in the 2021/2022 RPM Base Residual Auction. The EMAAC, PSEG, BGE, ATSI and COMED LDAs were binding constraints in the auction resulting in a Locational Price Adder for these LDAs. A

# 2021/2022 RPM Base Residual Auction Results

Locational Price Adder represents the difference in Resource Clearing Prices for the Capacity Performance product between a resource in a constrained LDA and the immediate higher level LDA. Table 4 contains a summary of the clearing results in the LDAs from the 2021/2022 RPM Base Residual Auction.

### Table 4 –RPM Base Residual Auction Clearing Results in the LDAs

| Auction Results | RTO | MAAC | SWMAAC | PEPCO | BGE | EMAAC | DPL-SOUTH | PSEG | PS-NORTH | ATSI | ATSI-CLEVELAND | PPL | COMED | DAY | DEOK |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Offered MW (UCAP)* | 186,505.8 | 73,578.3 | 12,102.2 | 6,222.9 | 3,463.9 | 32,044.5 | 1,785.6 | 5,987.4 | 3,507.5 | 12,038.1 | 2,487.1 | 11,451.8 | 27,930.4 | 1,660.7 | 3,414.8 |
| Cleared MW (UCAP)** | 163,627.3 | 67,365.9 | 10,106.7 | 5,948.8 | 1,937.7 | 29,288.5 | 1,673.8 | 5,367.6 | 3,133.3 | 8,007.3 | 1,248.0 | 11,233.1 | 22,358.1 | 1,636.7 | 2,733.3 |
| System Marginal Price | $140.00 | $140.00 | $140.00 | $140.00 | $140.00 | $140.00 | $140.00 | $140.00 | $140.00 | $140.00 | $140.00 | $140.00 | $140.00 | $140.00 | $140.00 |
| Locactional Price Adder*** | $0.00 | $0.00 | $0.00 | $0.00 | $60.30 | $25.73 | $0.00 | $38.56 | $0.00 | $31.33 | $0.00 | $0.00 | $55.55 | $0.00 | $0.00 |
| RCP for Capacity Performance Resources | $140.00 | $140.00 | $140.00 | $140.00 | $200.30 | $165.73 | $165.73 | $204.29 | $204.29 | $171.33 | $171.33 | $140.00 | $195.55 | $140.00 | $140.00 |

* Offered MW values include Annual, Summer-Period, and Winter-Period Capacity Performance sell offers

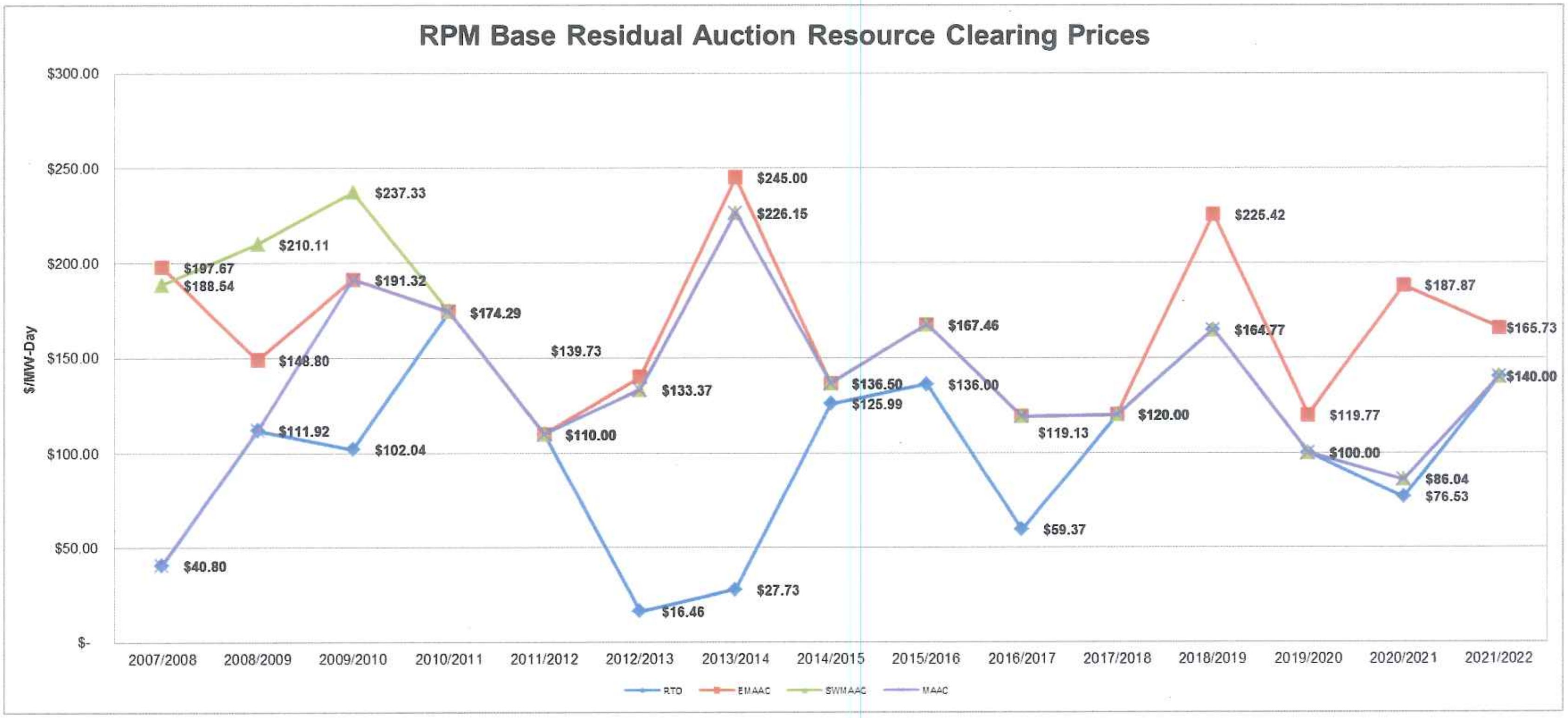
** Cleared MW values include Annual and matched Seasonal Capacity Performance sell offers within the LDA

*** Locational Price Adder is with respect to the immediate parent LDA

Since the EMAAC LDA, PSEG LDA, BGE LDA, ATSI LDA and COMED LDAs were constrained LDAs, Capacity Transfer Rights (CTRs) will be allocated to loads in these constrained LDA for the 2021/2022 Delivery Year. CTRs are allocated by load ratio share to all Load Serving Entities (LSEs) in a constrained LDA that has a higher clearing price than the unconstrained region. CTRs serve as a credit back to the LSEs in the constrained LDA for use of the transmission system to import less expensive capacity into that constrained LDA and are valued at the difference in the clearing prices of the constrained and unconstrained regions.

## 2021/2022 RPM Base Residual Auction Results

### Figure 2 – Base Residual Auction Resource Clearing Prices




* 2014/2015 through 2021/2022 Prices reflect the Annual Resource Clearing Prices.

## 2021/2022 RPM Base Residual Auction Results

Table 5 contains a summary of the RTO resources for each cleared BRA from 2008/2009 through the 2021/2022 Delivery Years. The summary includes all resources located in the RTO (including FRR Capacity Plans).

A total of 216,350.2 MW of installed capacity was eligible to be offered into the 2021/2022 Base Residual Auction, with 4,725.0 MW from external resources. As illustrated in Table 5, the amount of capacity exports in the 2021/2022 auction was unchanged from that of the previous auction and FRR commitments decreased by 274.2 MW from the 2020/2021 Delivery Year to 13,657.4 MW.

A total of 192,449.2 MW of capacity was offered into the Base Residual Auction. This is an increase of 2,531.4 MW from that which was offered into the 2020/2021 BRA. A total of 23,901.0 MW was eligible, but not offered due to either (1) inclusion in an FRR Capacity Plan, (2) export of the resource, or (3) having been excused from offering into the auction. Resources were excused from the must offer requirement for the following reasons: approved retirement requests not yet reflected in eRPM, resources categorically exempt from the Capacity Performance must-offer requirement, resources which received an exemption from the must-offer or Capacity Performance must-offer requirement and excess capacity owned by an FRR entity.

# 2021/2022 RPM Base Residual Auction Results

## Table 5 –RPM Base Residual Auction Generation, Demand, and Energy Efficiency Resource Information in the RTO

| | RTO[1] | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Auction Supply (all values in ICAP) | 2008/2009 | 2009/2010 | 2010/2011 | 2011/2012[2] | 2012/2013 | 2013/2014[3] | 2014/2015[4] | 2015/2016[5] | 2016/2017[6] | 2017/2018 | 2018/2019 | 2019/2020 | 2020/2021 | 2021/2022 |
| Internal PJM Capacity | 166,037.9 | 167,026.3 | 168,457.3 | 169,241.6 | 179,791.2 | 195,633.4 | 199,375.5 | 207,559.1 | 208,098.0 | 202,477.4 | 203,300.6 | 207,579.6 | 207,555.1 | 211,625.2 |
| Imports Offered | 2,612.0 | 2,563.2 | 2,982.4 | 6,814.2 | 4,152.4 | 4,766.1 | 7,620.2 | 4,649.7 | 8,412.2 | 6,300.9 | 5,724.6 | 4,821.4 | 5,440.5 | 4,725.0 |
| **Total Eligible RPM Capacity** | **168,649.9** | **169,589.5** | **171,439.7** | **176,055.8** | **183,943.6** | **200,399.5** | **206,995.7** | **212,208.8** | **216,510.2** | **208,778.3** | **209,025.2** | **212,401.0** | **212,995.6** | **216,350.2** |
| Exports / Delistings | 4,205.8 | 2,240.9 | 3,378.2 | 3,389.2 | 2,783.9 | 2,624.5 | 1,230.1 | 1,218.8 | 1,218.8 | 1,223.2 | 1,313.4 | 1,318.2 | 1,319.8 | 1,319.8 |
| FRR Commitments | 24,953.5 | 25,316.2 | 26,305.7 | 25,921.2 | 26,302.1 | 25,793.1 | 33,612.7 | 15,997.9 | 15,576.6 | 15,776.1 | 15,793.0 | 15,385.3 | 13,931.6 | 13,657.4 |
| Excused | 722.0 | 1,121.9 | 1,290.7 | 1,580.0 | 1,732.2 | 1,825.7 | 3,255.2 | 8,712.9 | 8,524.0 | 4,305.3 | 2,348.4 | 1,454.5 | 7,826.4 | 8,923.8 |
| **Total Eligible RPM Capacity: Excused** | **29,881.3** | **28,679.0** | **30,974.6** | **30,890.4** | **30,818.2** | **30,243.3** | **38,098.0** | **25,929.6** | **25,319.4** | **21,304.6** | **19,454.8** | **18,158.0** | **23,077.8** | **23,901.0** |
| **Remaining Eligible RPM Capacity** | **138,768.6** | **140,910.5** | **140,465.1** | **145,165.4** | **153,125.4** | **170,156.2** | **168,897.7** | **186,279.2** | **191,190.8** | **187,473.7** | **189,570.4** | **194,243.0** | **189,917.8** | **192,449.2** |
| Generation Offered | 138,076.7 | 140,003.6 | 139,529.5 | 143,568.1 | 142,957.7 | 156,894.1 | 153,048.1 | 166,127.8 | 176,145.3 | 175,329.5 | 177,592.1 | 181,866.4 | 178,807.1 | 178,823.5 |
| DR Offered | 691.9 | 906.9 | 935.6 | 1,597.3 | 9,535.4 | 12,528.7 | 15,043.1 | 19,243.6 | 13,932.9 | 10,855.2 | 10,772.8 | 10,859.2 | 9,047.8 | 10,911.9 |
| EE Offered | 0.0 | 0.0 | 0.0 | 0.0 | 632.3 | 733.4 | 806.5 | 907.8 | 1,112.6 | 1,289.0 | 1,205.5 | 1,517.4 | 2,062.9 | 2,713.8 |
| **Total Eligible RPM Capacity Offered** | **138,768.6** | **140,910.5** | **140,465.1** | **145,165.4** | **153,125.4** | **170,156.2** | **168,897.7** | **186,279.2** | **191,190.8** | **187,473.7** | **189,570.4** | **194,243.0** | **189,917.8** | **192,449.2** |
| **Total Eligible RPM Capacity Unoffered** | **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** |

[1]RTO numbers include all LDAs.

[2]All generation in the Duquesne zone is considered external to PJM for the 2011/2012 BRA.

[3]2013/2014 includes ATSI zone and generation

[4]2014/2015 includes Duke zone and generation

[5]2015/2016 includes a significant portion of AEP and DEOK zone load previously under the FRR Alternative

[6]2016/2017 includes EKPC zone

Table 6 shows the Generation, DR, and EE Resources Offered and Cleared in the RTO translated into Unforced Capacity (UCAP) MW amounts. Participants' sell offer EFORd values were used to translate the generation installed capacity values into unforced capacity (UCAP) values. DR sell offers and EE sell offers were converted into UCAP using the appropriate Forecast Pool Requirement (FPR) and Demand Resource Factor, when applicable, for the Delivery Year.

In UCAP terms, a total of 186,504.8 MW were offered into the 2021/2022 BRA, comprised of 171,663.2 MW of generation capacity, 11,886.8 MW of capacity from DR, and 2,954.8 MW of capacity from EE resources. Of those offered, a total of 163,627.3 MW of capacity was cleared in the BRA.

Of the 163,627.3 MW of capacity that cleared in the auction, a total of 150,385.0 MW cleared from Generation Capacity Resources, 11,125.8 MW cleared from DR, and 2,832.0 MW cleared from EE resources. Of which, 715.5 MW cleared as matched seasonal CP resources. Capacity that was offered but not cleared in the BRA Auction will be eligible to offer into the First, Second and Third Incremental Auctions for the 2021/2022 Delivery Year.

# 2021/2022 RPM Base Residual Auction Results

## Table 6 – Generation, Demand Resources, and Energy Efficiency Resources Offered and Cleared in UCAP MW

| | RTO* | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Auction Results** | 2008/2009 | 2009/2010 | 2010/2011 | 2011/2012 | 2012/2013 | 2013/2014 | 2014/2015 | 2015/2016 | 2016/2017 | 2017/2018 | 2018/2019 | 2019/2020 | 2020/2021 | 2021/2022 |
| Generation Offered | 131,164.8 | 132,614.2 | 132,124.8 | 136,067.9 | 134,873.0 | 147,188.6 | 144,108.8 | 157,691.1 | 168,716.0 | 166,204.8 | 166,909.6 | 172,071.2 | 171,262.3 | 171,663.2 |
| DR Offered | 715.8 | 936.8 | 967.9 | 1,652.4 | 9,847.6 | 12,952.7 | 15,545.6 | 19,956.3 | 14,507.2 | 11,293.7 | 11,675.5 | 11,818.0 | 9,846.7 | 11,886.8 |
| EE Offered | - | - | - | - | 652.7 | 756.8 | 831.9 | 940.3 | 1,156.8 | 1,340.0 | 1,306.1 | 1,650.3 | 2,242.5 | 2,954.8 |
| **Total Offered** | **131,880.6** | **133,551.0** | **133,092.7** | **137,720.3** | **145,373.3** | **160,898.1** | **160,486.3** | **178,587.7** | **184,380.0** | **178,838.5** | **179,891.2** | **185,539.5** | **183,351.5** | **186,504.8** |
| Generation Cleared | 129,061.4 | 131,338.9 | 131,251.5 | 130,856.6 | 128,527.4 | 142,782.0 | 135,034.2 | 148,805.9 | 155,634.3 | 154,690.0 | 154,506.0 | 155,442.8 | 155,976.5 | 150,385.0 |
| DR Cleared | 536.2 | 892.9 | 939.0 | 1,364.9 | 7,047.2 | 9,281.9 | 14,118.4 | 14,832.8 | 12,408.1 | 10,974.8 | 11,084.4 | 10,348.0 | 7,820.4 | 11,125.8 |
| EE Cleared | 0.0 | 0.0 | 0.0 | 0.0 | 568.9 | 679.4 | 822.1 | 922.5 | 1,117.3 | 1,338.9 | 1,246.5 | 1,515.1 | 1,710.2 | 2,832.0 |
| **Total Cleared** | **129,597.6** | **132,231.8** | **132,190.5** | **132,221.5** | **136,143.5** | **152,743.3** | **149,974.7** | **164,561.2** | **169,159.7** | **167,003.7** | **166,836.9** | **167,305.9** | **165,109.2** | **163,627.3** |
| Uncleared | 2,283.0 | 1,319.2 | 902.2 | 5,498.8 | 9,229.8 | 8,154.8 | 10,511.6 | 14,026.5 | 15,220.3 | 11,834.8 | 13,054.3 | 18,233.6 | 18,242.3 | 22,877.5 |

* RTO numbers include all LDAs

** UCAP calculated using sell offer EFORd for Generation Resources. DR and EE UCAP values include appropriate FPR and DR Factor.

***Starting 2020/2021: Generation, DR, and EE offered and cleared values include Annual, Summer-Period, and Winter-Period Capacity Performa

***Starting 2020/2021: Total RTO Cleared MW value includes Annual and matched Seasonal Capacity Performance sell offers

# 2021/2022 RPM Base Residual Auction Results

Table 7 contains a summary of capacity additions and reductions from the 2007/2008 BRA to the 2021/2022 BRA. A total of 1,196.9 MW of incrementally new capacity in PJM was available for the 2021/2022 BRA. This incrementally new capacity includes new Generation Capacity Resources and capacity upgrades to existing and planned Generation Capacity Resources. The increase is offset by generation capacity deratings on existing Generation Capacity Resources, and supplemented by an increase in the quantity of offered DR and EE to yield a net increase of 2,020.2 MW of installed capacity as compared to last year's BRA.

Table 7 also illustrates the total amount of resource additions and reductions over fifteen Delivery Years since the implementation of the RPM construct. Over the period covering the first fifteen RPM BRAs, 51,988.9 MW of new generation capacity was added, which was partially offset by 41,331.2 MW of capacity de-ratings or retirements over the same period. Additionally, 11,349.7 MW of new DR and 2,713.8 MW of new EE resources were offered over the course of the fifteen Delivery Years since RPM's inception. The total net increase in installed capacity in PJM over the period of the last fifteen RPM auctions was 24,721.2 MW.

### Table 7 – Incremental Capacity Resource Additions and Reductions to Date

| | RTO* | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Capacity Changes (in ICAP) | 2007/2008 | 2008/2009 | 2009/2010 | 2010/2011 | 2011/2012 | 2012/2013 | 2013/2014[1] | 2014/2015[2] | 2015/2016 | 2016/2017[3] | 2017/2018 | 2018/2019 | 2019/2020 | 2020/2021 | 2021/2022 | Total |
| Increase in Generation Capacity | 602.0 | 724.2 | 1,272.3 | 1,776.2 | 3,576.3 | 1,893.5 | 1,737.5 | 1,582.8 | 8,207.0 | 6,806.0 | 6,973.3 | 5,055.6 | 6,327.8 | 4,257.5 | 1,196.9 | 51,988.9 |
| Decrease in Generation Capacity | -674.6 | -375.4 | -550.2 | -301.8 | -264.7 | -3,253.9 | -1,924.1 | -1,550.1 | -6,432.6 | -4,992.0 | -9,760.1 | -3,620.8 | -2,923.1 | -3,016.1 | -1,691.7 | -41,331.2 |
| Net Increase in Demand Resource | 555.0 | 574.7 | 215.0 | 28.7 | 661.7 | 7,938.1 | 2,993.3 | 2,514.4 | 4,200.5 | -5,310.7 | -3,077.7 | -82.4 | 86.4 | -1,811.4 | 1,864.1 | 11,349.7 |
| Net Increase in Energy Efficiency | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 632.3 | 101.1 | 73.1 | 101.3 | 204.8 | 176.4 | -83.5 | 311.9 | 545.5 | 650.9 | 2,713.8 |
| **Net Increase in Installed Capacity** | **482.4** | **923.5** | **937.1** | **1503.1** | **3973.3** | **7,210.0** | **2,907.8** | **2,620.2** | **6,076.2** | **-3,291.9** | **-5,688.1** | **1,268.9** | **3,803.0** | **-24.5** | **2,020.2** | **24,721.2** |

* RTO numbers include all LDAs

** Values are with respect to the quantity offered in the previous year's Base Residual Auction.

1) Does not include Existing Generation located in ATSI Zone

2) Does not include Existing Generation located in Duke Zone

3) Does not include Existing Generation located in EKPC Zone

Table 7A provides a further breakdown of the generation increases and decreases for the 2021/2022 Delivery Year on an LDA basis.

**Table 7A – Generation Increases and Decreases by LDA Effective 2021/2022 Delivery Year**

| LDA Name | Increases | Decreases |
|---|---|---|
| EMAAC | 102.3 | (640.2) |
| MAAC* | 330.4 | (712.2) |
| **Total RTO**** | **1,196.9** | **(1,691.7)** |

All Values in ICAP terms
*MAAC includes EMAAC
**RTO includes MAAC

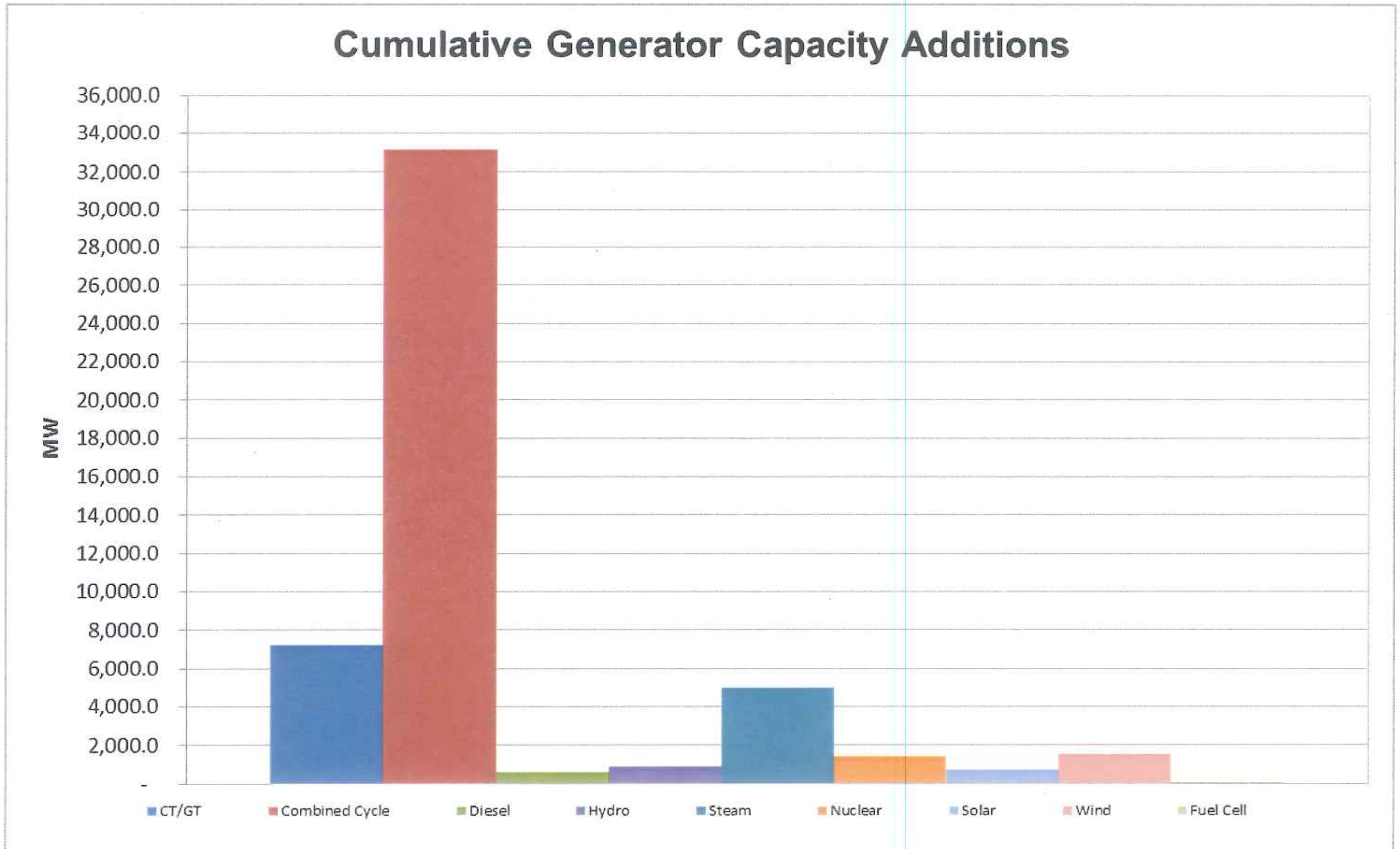
Table 8 provides a breakdown of the new capacity offered into the each BRA into the categories of new resources, reactivated units, and uprates to existing capacity, and then further down into resource type. As shown in this table, there was a significant reduction in generating capacity from new resources and uprates to existing resources offered into the 2021/2022 BRA as compared to last year's BRA. The capacity offered in the 2021/2022 BRA resulted from both new generating resources and uprates to existing resources including gas, diesel, wind, and solar resources. As shown in Figure 3, the largest growth remains in combined cycle plants.

# 2021/2022 RPM Base Residual Auction Results

## Table 8 – Further Breakdown of Incremental Capacity Resource Additions from 2007/2008 to 2021/2022

| | Delivery Year | CT/GT | Combined Cycle | Diesel | Hydro | Steam | Nuclear | Solar | Wind | Fuel Cell | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|
| New Capacity Units (ICAP MW) | 2007/2008 | | | 18.7 | 0.3 | | | | | | 19.0 |
| | 2008/2009 | | | 27.0 | | | | | 66.1 | | 93.1 |
| | 2009/2010 | 399.5 | | 23.8 | | 53.0 | | | | | 476.3 |
| | 2010/2011 | 283.3 | 580.0 | 23.0 | | | | | 141.4 | | 1,027.7 |
| | 2011/2012 | 416.4 | 1,135.0 | | | 704.8 | | 1.1 | 75.2 | | 2,332.5 |
| | 2012/2013 | 403.8 | | 7.8 | | 621.3 | | | 75.1 | | 1,108.0 |
| | 2013/2014 | 329.0 | 705.0 | 6.0 | | 25.0 | | 9.5 | 245.7 | | 1,320.2 |
| | 2014/2015 | 108.0 | 650.0 | 35.1 | 132.9 | | | 28.0 | 146.6 | | 1,100.6 |
| | 2015/2016 | 1,382.5 | 5,914.5 | 19.4 | 148.4 | 45.4 | | 13.8 | 104.9 | 30.0 | 7,658.9 |
| | 2016/2017 | 171.1 | 4,994.5 | 38.3 | | 24.0 | | 32.1 | 54.3 | | 5,314.3 |
| | 2017/2018 | 131.0 | 5,010.0 | 124.8 | 6.0 | 90.0 | | 27.0 | | | 5,388.8 |
| | 2018/2019 | 1,032.5 | 2,352.3 | 29.9 | | | | 82.8 | 127.1 | | 3,624.6 |
| | 2019/2020 | 167.0 | 6,145.0 | 29.9 | | | | 152.3 | 73.0 | | 6,567.2 |
| | 2020/2021 | | 2,410.0 | 26.3 | 4.0 | | | 94.3 | 30.2 | | 2,564.8 |
| | 2021/2022 | | | 19.9 | | | | 237.8 | 65.7 | | 323.4 |
| Capacity from Reactivated Units (ICAP MW) | 2007/2008 | | | | | 47.0 | | | | | 47.0 |
| | 2008/2009 | | | | | 131.0 | | | | | 131.0 |
| | 2009/2010 | | | | | | | | | | - |
| | 2010/2011 | 160.0 | | 10.7 | | | | | | | 170.7 |
| | 2011/2012 | 80.0 | | | | 101.0 | | | | | 181.0 |
| | 2012/2013 | | | | | | | | | | - |
| | 2013/2014 | | | | | | | | | | - |
| | 2014/2015 | | | 9.0 | | | | | | | 9.0 |
| | 2015/2016 | | | | | | | | | | - |
| | 2016/2017 | | | | | 21.0 | | | | | 21.0 |
| | 2017/2018 | | | | | 991.0 | | | | | 991.0 |
| | 2018/2019 | | | | | | | | | | - |
| | 2019/2020 | | | | | | | | | | - |
| | 2020/2021 | | | | | | | | | | - |
| | 2021/2022 | | | | | | | | | | - |
| Uprates to Existing Capacity Resources (ICAP MW) | 2007/2008 | 114.5 | | 13.9 | 80.0 | 235.6 | 92.0 | | | | 536.0 |
| | 2008/2009 | 108.2 | 34.0 | 18.0 | 105.5 | 196.0 | 38.4 | | | | 500.1 |
| | 2009/2010 | 152.2 | 206.0 | | 162.5 | 61.4 | 197.4 | | 16.5 | | 796.0 |
| | 2010/2011 | 117.3 | 163.0 | | 48.0 | 89.2 | 160.3 | | | | 577.8 |
| | 2011/2012 | 369.2 | 148.6 | 57.4 | | 186.8 | 292.1 | | 8.7 | | 1,062.8 |
| | 2012/2013 | 231.2 | 164.3 | 14.2 | | 193.0 | 126.0 | | 56.8 | | 785.5 |
| | 2013/2014 | 56.4 | 59.0 | 0.3 | | 215.0 | 47.0 | | 39.6 | | 417.3 |
| | 2014/2015 | 104.9 | | 0.5 | 41.5 | 138.6 | 107.0 | 7.1 | 73.6 | | 473.2 |
| | 2015/2016 | 216.8 | 72.0 | 4.7 | 15.7 | 63.4 | 149.2 | 2.2 | 24.1 | | 548.1 |
| | 2016/2017 | 436.6 | 420.0 | 3.3 | 7.4 | 484.3 | 102.6 | 1.7 | 14.8 | | 1,470.7 |
| | 2017/2018 | 71.9 | 212.5 | 5.1 | 105.9 | 64.8 | 11.0 | 0.4 | 2.1 | | 473.7 |
| | 2018/2019 | 33.4 | 548.0 | 2.4 | 22.9 | 11.9 | 79.3 | - | 14.9 | - | 712.8 |
| | 2019/2020 | 29.3 | 72.5 | 3.9 | 5.2 | 65.3 | - | - | 46.8 | - | 223.0 |
| | 2020/2021 | 9.3 | 588.8 | 1.2 | 4.6 | 5.7 | | 1.0 | 14.7 | | 625.3 |
| | 2021/2022 | 100.2 | 549.9 | 7.1 | 3.6 | 91.9 | | 24.2 | 18.4 | | 795.3 |
| | Total | 7,215.5 | 33,134.9 | 581.6 | 894.4 | 4,957.4 | 1,402.3 | 715.3 | 1,536.3 | 30.0 | 50,467.7 |

**Figure 3: Cumulative Generation Capacity Increases by Fuel Type**



## 2021/2022 RPM Base Residual Auction Results

Table 9 shows the changes that have occurred regarding resource deactivation and retirement since the RPM was approved by FERC. The MW values shown in Table 9 represent the quantity of unforced capacity cleared in the 2021/2022 Base Residual Auction that came from resources that have either withdrawn their request to deactivate, postponed retirement, or been reactivated (i.e., came out of retirement or mothball state for the RPM auctions) since the inception of RPM. This total accounts for 7,588.7 MW of cleared UCAP in the 2021/2022 BRA which equates to 9,207.6 MW of ICAP Offered.

**Table 9 – Changes to Generation Retirement Decisions since Commencement of RPM in 2007/2008**

| | RTO* | |
|---|---|---|
| Generation Resource Decision Changes | ICAP Offered | UCAP Cleared |
| Withdraw n Deactivation Requests | 3,349.6 | 3,128.1 |
| Postponed or Cancelled Retirement | 4,355.2 | 3,758.5 |
| Reactivation | 1,502.8 | 702.1 |
| **Total** | **9,207.6** | **7,588.7** |

### RPM Impact to Date

As illustrated in Table 5, for the 2021/2022 auction, the capacity exports were 1,319.8 MW and the offered capacity imports were 4,725.0 MW. The difference between the capacity imports and exports results is a net capacity import of 3,405.2 MW. In the planning year preceding the RPM auction implementation, 2006/2007, there was a net capacity export of 2,616.0 MW. In this auction, PJM is now a net importer of 3,405.2 MW. Therefore, RPM's impact on PJM capacity interchange is 6,021.2 MW.

The minimum net impact of the RPM implementation on the availability of Installed Capacity resources for the 2021/2022 planning year can be estimated by adding the net change in capacity imports and exports over the period, the forward demand and energy efficiency resources, the increase in Installed Capacity over the RPM implementation period from Table 8 and the net change in generation retirements from Table 9. Therefore, as illustrated in Table 10, the minimum estimated net impact of the RPM implementation on the availability of capacity in the 2021/2022 compared to what would have happened absent this implementation is 77,773.0 MW.

Table 10 shows the details on RPM's impact to date in ICAP terms.

**Table 10 – RPM's Impact to Date**

| Change in Capacity Availability | Installed Capacity MW |
|---|---|
| New Generation | 38,919.4 |
| Generation Upgrades (not including reactivations) | 9,997.6 |
| Generation Reactivation | 1,550.7 |
| Forward Demand and Energy Efficiency Resources | 14,063.5 |
| Cleared ICAP from Withdrawn or Cancelled Retirements | 7,220.6 |
| Net increase in Capacity Imports | 6,021.2 |
| **Total Impact on Capacity Availability in 2021/2022 Delivery Year** | **77,773.0** |

## 2021/2022 RPM Base Residual Auction Results

**Discussion of Factors Impacting the RPM Clearing Prices**

The main factors impacting 2021/2022 RPM BRA clearing prices relative to 2020/2021 BRA clearing prices are provided below, separated out by changes to the demand-side and supply-side of the market.

*Changes that impacted the Demand Curve:*

- The forecast peak load for the PJM RTO for the 2021/2022 Delivery Year is 152,647.4 MW which is 1,267.6 MW or about 0.8% below the forecast peak load of 153,915 MW for the 2020/2021 BRA. This reduction was manifested in a 1,200 MW decrease in the reliability requirement for the RTO as compared to last year's BRA.

- 510 MW of Price Responsive Demand has elected to participate in the 2021/2022 Base Residual Auction: 240 MW in the BGE LDA, 195 MW in the PEPCO LDA, and 75 MW in the EMAAC LDA (with 35.7 MW located in the DPL-South LDA).

- The Net CONE used to develop the VRR Curve increased for the RTO and for all of the modeled LDAs. The increase in Net CONE values was driven primarily by a decrease in the Net E&AS for the RTO and all LDAs. The Net E&AS values for the 2021/2022 BRA were lower than those of the 2020/2021 BRA because the updated three-year rolling average Net E&AS replaced 2014 calendar year values with 2017 calendar year values, with the 2014 calendar year Net E&AS values being significantly greater than the 2017 calendar year Net E&AS values.

*Changes that impacted the Supply Curve:*

- The 2021/2022 BRA is the second BRA for which PJM has procured only Capacity Performance ("CP") Resources.
  - Annual CP capacity offered by intermittent resources is 928.7 MW higher than the annual CP capacity offered by intermittent resources in the 2020/2021 BRA.
  - Annual CP capacity offered by DR is 2,727.4 MW higher than the annual CP capacity offered by DR in the 2020/2021 BRA.

- Annual CP capacity offered by EE is 810.0 MW higher than the annual CP capacity offered by EE in the 2020/2021 BRA.

- 715.5 MW of seasonal capacity resources cleared in an aggregated manner to form a year-round commitment. This is an increase of 317.5 MW over the 398 MW of seasonal capacity resources that cleared in an aggregated manner in the 2020/2021 BRA. 715.5 MW of summer CP resources comprised of 452.3 MW of summer DR, 209.3 MW of summer EE and 53.9 MW of intermittent resources cleared along with 715.5 MW of winter CP resources comprised mainly of winter capability from wind resources.

- New generation capacity of 1,098.5 MW was offered into the BRA comprised of 322.2 of new generation and 776.3 MW of uprates.

- In general, offer prices from supply resources were higher in this auction compared to the prior auction, likely reflecting the continuing decrease in energy revenues and the associated impact on revenues required from the capacity market.

**EXHIBIT KMM-3**

# Generation and Transmission Planning[1]

## Overview

### Generation Interconnection Planning

#### Existing Generation Mix

- As of September 30, 2018, PJM had an installed capacity of 195,488.2 MW, of which 57,891.9 MW (29.6 percent) are coal fired steam units, 43,063.1 MW (22.0 percent) are combined cycle units and 34,257.6 MW (17.5 percent) are nuclear units. This measure of installed capacity differs from capacity market installed capacity because it includes energy only units, excludes all external units, and uses nameplate values for solar and wind resources.
- The largest zone by total installed capacity is AEP. Of the 195,488.2 MW of PJM installed capacity, 31,343.0 MW (16.0 percent) are in the AEP Zone, of which 14,727.8 MW (47.0 percent) are coal fired steam units, 6,990.0 MW (22.3 percent) are combined cycle units and 2,071.0 MW (6.6 percent) are nuclear units.
- The largest state by total installed capacity is Pennsylvania. Of the 195,488.2 MW of installed capacity, 43,207.6 MW (22.1 percent) are in Pennsylvania, of which 12,112.5 MW (28.0 percent) are combined cycle units, 9,648.8 MW (22.3 percent) are nuclear units and 9,467.7 MW (21.9 percent) are coal fired steam units.
- Of the 195,488.2 MW of installed capacity, 76,587.5 MW (39.2 percent) are from units older than 40 years, of which 41,426.7 MW (54.1 percent) are coal fired steam units and 16,044.9 MW (20.9 percent) are nuclear units.

#### Generation Retirements[2]

- There are 43,125.6 MW of generation that have been, or are planned to be, retired between 2011 and 2021, of which 30,821.4 MW (71.5 percent) are coal fired steam units. Coal unit retirements are primarily a result of the inability of coal units to compete with efficient combined cycle units burning low cost gas.
- In the first nine months of 2018, 4,894.2 MW of generation retired. The largest generator that retired in first nine months of 2018 was the joint owned 600 MW Killen 2 unit (402 MW owned by AES Corporation and 198 MW owned by Vistra Energy Corporation) located in the Dayton Power and Light (DAY) Zone. Of the 4,894.2 MW of generation that retired, 2,364.0 MW (48.3 percent) were located in the DAY Zone.
- There are 12,468.0 MW of generation that have requested retirement after September 30, 2018, of which 6,791.0 MW (54.5 percent) are located in the ATSI Zone, 7,341.8 MW (58.9 percent) are coal fired steam units and 4,716.0 MW (37.8 percent) are nuclear units. The largest generator pending retirement is the 1,240 MW Perry U1 Nuclear Generating Unit located in the ATSI Zone.

#### Generation Queue[3]

- The total MW in queues increased by 22,169.1 MW (28.0 percent) from 79,224.3 MW at the end of 2017 to 101,393.4 MW on September 30, 2018.
- A significant shift in the distribution of unit types within the PJM footprint continues to develop as natural gas fired units enter the queue and coal fired steam units retire. As of September 30, 2018, there were 50,201.7 MW of natural gas fired capacity active, suspended or under construction in PJM queues (including combined cycle units, CTs, RICE units, and natural gas fired steam units). As of September 30, 2018, there were only 147.0 MW of coal fired steam capacity active, suspended or under construction in PJM queues.
- As of September 30, 2018, 3,969 projects, representing 504,007.2 MW, have entered the queue process since its inception in 1998. Of those, 805 projects, representing 59,737.9 MW, went into service. Of the projects that entered the queue process, 2,323 projects, representing 342,875.9 MW (68.0 percent of the MW) withdrew prior to completion. Such projects may create barriers to entry for projects that would otherwise be completed by

1 Totals presented in this section include corrections to historical data and may not match totals presented in previous reports.
2 See PJM "Generator Deactivations," at <http://www.pjm.com/planning/services-requests/gen-deactivations.aspx>.
3 See PJM "New Services Queue," at <https://www.pjm.com/planning/services-requests/interconnection-queues.aspx>.

taking up queue positions, increasing interconnection costs and creating uncertainty.

# Regional Transmission Expansion Plan (RTEP)

## Backbone Facilities

- There are currently three backbone projects under development, Surry Skiffes Creek 500kV, and the conversion of the Marion-Bayonne and Bayway-Linden lines from 138 kV to 345 kV.[4]

## Market Efficiency Process

- Through September 30, 2018, PJM has completed two market efficiency cycles. In the first cycle, PJM received 93 proposals for 57 identified issues. In the second market efficiency cycle, PJM received 96 proposals for four identified issues. The proposal window for 2018/2019 will open on November 1, 2018, and will close on Februray 28, 2019.
- Approved market efficiency projects periodically undergo a reevaluation process to ensure that the benefit/cost ratio continues to meet the 1.25:1 threshold. The Transource AP-South project was reevaluated in September 2017, February 2018 and again in September 2018. The project exceeded the 1.25:1 threshold in all reevaluations.

## PJM MISO Interregional Targeted Market Efficiency Process (TMEP)

- The first Targeted Market Efficiency Process (TMEP) analysis occurred in 2017 and included the investigation of congestion on 50 market to market flowgates. The study resulted in the evaluation of 13 potential upgrades, resulting in the recommendation of five TMEP projects. The five projects address $59 million in historical congestion, with a TMEP benefit of $99.6 million. The projects have a total cost of $20 million, with a 5.0 average benefit/cost ratio. PJM and MISO presented the five recommended projects to their boards in December, 2017, and both boards approved all five projects.[5]
- The 2018 TMEP analysis included the investigation of congestion on 61 market to market flowgates. The study resulted in the evaluation of 19 potential upgrades, resulting in the recommendation of two TMEP projects. The two projects address $25 million in historical congestion, with a TMEP benefit of $31.9 million. The projects have a total cost of $4.5 million, with a 7.1 average benefit/cost ratio. PJM and MISO will present the two recommended projects to their boards for approval in December, 2018.[6]

## Supplemental Transmission Projects

- The average number of supplemental projects in each expected in service year increased by 500.0 percent, from 20 for years 1998 through 2007 (pre Order 890) to 120 for years 2008 through 2018 (post Order 890).

## End of Life Transmission Projects

- An end of life transmission project is a project submitted for the purpose of replacing existing infrastructure that has, or is approaching, the end of its useful life. End of life transmission projects fall under the Transmission Owner Form 715 Planning Criteria, and are currently exempt from the competitive planning process.[7] End of life transmission projects are already included in the supplemental projects totals or, if included in the transmission owners' reliability plan, will be included in the baseline project list as a reliability criteria project.

## Board Authorized Transmission Upgrades

- The Transmission Expansion Advisory Committee (TEAC) regularly reviews internal and external proposals to improve transmission reliability throughout PJM. These proposals are periodically presented to the PJM

4 See "2017 RTEP Process Scope and Input Assumptions White Paper," P 25. <http://www.pjm.com/-/media/library/reports-notices/2017-rtep/20170731-rtep-input-assumptions-and-scope-whitepaper.ashx?la=en>.

5 See PJM. "*MISO PJM IPSAC,*" (January 12, 2018) <http://www.pjm.com/-/media/committees-groups/stakeholder-meetings/ipsac/20180112/20180112-ipsac-presentation.ashx>.

6 See PJM. "*MISO PJM IPSAC,*" (October 5, 2018) <https://www.pjm.com/-/media/committees-groups/stakeholder-meetings/ipsac/20181005/20181005-ipsac-presentation.ashx>.

7 See PJM Operating Agreement, Schedule 6 § 1.5.8(o).

Board of Managers for authorization. In the first nine months of 2018, the PJM Board approved $1.60 billion in upgrades.

## Transmission Competition

- The MMU makes several recommendations related to the competitive transmission planning process. The recommendations include improved process transparency, incorporation of competition between transmission and generation alternatives and the removal of barriers to competition from merchant transmission. These recommendations will ensure that the process is an open and transparent process that results in the most cost effective solutions.
- On May 24, 2018, the PJM Markets and Reliability Committee (MRC) approved a motion that required PJM to develop a comparative framework to evaluate the quality and effectiveness of binding cost containment proposals versus proposals without cost containment provisions. The initial motion required the comparative framework to be presented at the December 2018 meeting of the MRC for vote and to be effective for the 2018 long lead project proposal window. At the August 23, 2018, meeting of the MRC, the committee approved a motion to delay the comparative framework deadlines by one year.

## Transmission Facility Outages

- PJM maintains a list of reportable transmission facilities. When the reportable transmission facilities need to be taken out of service, PJM transmission owners are required to report planned transmission facility outages as early as possible. PJM processes the transmission facility outage requests according to rules in PJM's Manual 3 to decide if the outage is on time or late and whether or not they will allow the outage.[8]
- There were12,123 transmission outage requests submitted in the 2018/2019 planning period. Of the requested outages, 70.5 percent of the requested outages were planned for less than or equal to five days and 10.2 percent of requested outages were planned for greater than 30 days. Of the requested outages, 37.9 percent were late according to the rules in PJM's Manual 3.

8 PJM, "Manual 03: Transmission Operations," Rev. 53 (June 1, 2018) Section 4.

# Recommendations

The MMU recommends improvements to the planning process:

## Generation Retirements

- The MMU recommends that the question of whether Capacity Injection Rights (CIRs) should persist after the retirement of a unit be addressed. Even if the treatment of CIRs remains unchanged, the rules need to ensure that incumbents cannot exploit control of CIRs to block or postpone entry of competitors.[9] (Priority: Low. First reported 2013. Status: Not adopted.)

## Generation Queue

- The MMU recommends that barriers to entry be addressed in a timely manner in order to help ensure that the capacity market will result in the entry of new capacity to meet the needs of PJM market participants and reflect the uncertainty and resultant risks in the cost of new entry used to establish the capacity market demand curve in RPM. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends improvements in queue management including that PJM establish a review process to ensure that projects are removed from the queue if they are not viable, as well as a process to allow commercially viable projects to advance in the queue ahead of projects which have failed to make progress, subject to rules to prevent gaming. (Priority: Medium. First reported 2013. Status: Partially adopted.)
- The MMU recommends continuing analysis of the study phase of PJM's transmission planning to reduce the need for postponements of study results, to decrease study completion times, and to improve the likelihood that a project at a given phase in the study process will successfully go into service. (Priority: Medium. First reported 2014. Status: Partially adopted.)

9 See "Comments of the Independent Market Monitor for PJM," Docket No. ER12-1177-000 <http://www.monitoringanalytics.com/reports/Reports/2012/IMM_Comments_ER12-1177-000_20120312.pdf>.

- The MMU recommends outsourcing interconnection studies to an independent party to avoid potential conflicts of interest. Currently, these studies are performed by incumbent transmission owners under PJM's direction. This creates potential conflicts of interest, particularly when transmission owners are vertically integrated and the owner of transmission also owns generation. (Priority: Low. First reported 2013. Status: Not adopted.)

## Market Efficiency Process

- The MMU recommends that PJM reevaluate the rules governing cost benefit analysis and cost allocation for economic projects. (Priority: Medium. New recommendation. Status: Not adopted.)

## Supplemental Transmission Projects

- The MMU recommends, to ensure maximum competition, that PJM support ending the exemption of supplemental projects from the Order No. 1000 competitive process and to review the basis for all such exemptions. (Priority: Medium. First reported 2017. Status: Not adopted.)

## Transmission Competition

- The MMU recommends that PJM enhance the transparency and queue management process for merchant transmission investment. Issues related to data access and complete explanations of cost impacts should be addressed. The goal should be to remove barriers to competition from merchant transmission. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM continue to incorporate the principle that the goal of transmission planning should be the incorporation of transmission investment decisions into market driven processes as much as possible. (Priority: Low. First reported 2001. Status: Not adopted.)
- The MMU recommends the creation of a mechanism to permit a direct comparison, or competition, between transmission and generation alternatives, including which alternative is less costly and who bears the risks associated with each alternative. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM establish fair terms of access to rights of way and property, such as at substations, in order to remove any barriers to entry and permit competition between incumbent transmission providers and merchant transmission providers in the RTEP. (Priority: Medium. First reported 2014. Status: Not adopted.)
- The MMU recommends that rules be implemented to permit competition to provide financing for transmission projects. This competition could reduce the cost of capital for transmission projects and significantly reduce total costs to customers. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that rules be implemented to require that project cost caps on new transmission projects be part of the evaluation of competing projects. (Priority: Low. First reported 2015. Status: Not adopted.)

## Transmission Facility Outages

- The MMU recommends consideration of changing the minimum distribution factor in the allocation from 0.01 to 0.00 and adding a threshold minimum usage impact on the line. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM reevaluate all transmission outage tickets as on time or late as if they were new requests when an outage is rescheduled and apply the standard rules for late submissions to any such outages. (Priority: Low. First reported 2014. Status: Not adopted.)
- The MMU recommends that PJM draft a clear definition of the congestion analysis required for transmission outage requests to include in Manual 3 after appropriate review. (Priority: Low. First reported 2015. Status: Not adopted.)

- The MMU recommends that PJM modify the rules to reduce or eliminate the approval of late outage requests submitted or rescheduled after the FTR auction bidding opening date. (Priority: Low. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM not permit transmission owners to divide long duration outages into smaller segments to avoid complying with the requirements for long duration outages. (Priority: Low. First reported 2015. Status: Not adopted.)

## Conclusion

The goal of PJM market design should be to enhance competition and to ensure that competition is the driver for all the key elements of PJM markets. But transmission investments have not been fully incorporated into competitive markets. The construction of new transmission facilities has significant impacts on the energy and capacity markets. But when generating units retire or load increases, there is no market mechanism in place that would require direct competition between transmission and generation to meet loads in the affected area. In addition, despite FERC Order No. 1000, there is not yet a transparent, robust and clearly defined mechanism to permit competition to build transmission projects, to ensure that competitors provide a total project cost cap, or to obtain least cost financing through the capital markets.

The addition of a planned transmission project changes the parameters of the capacity auction for the area, changes the amount of capacity needed in the area, changes the capacity market supply and demand fundamentals in the area and may effectively forestall the ability of generation to compete. But there is no mechanism to permit a direct comparison, let alone competition, between transmission and generation alternatives. There is no mechanism to evaluate whether the generation or transmission alternative is less costly, whether there is more risk associated with the generation or transmission alternatives, or who bears the risks associated with each alternative. Creating such a mechanism should be an explicit goal of PJM market design.

Managing the generation queues is a highly complex process. The PJM queue evaluation process has been substantially improved in recent years and it is more efficient and effective as a result. The PJM queue evaluation process should continue to be improved to help ensure that barriers to competition for new generation investments are not created. Issues that need to be addressed include the ownership rights to CIRs, whether transmission owners should perform interconnection studies, and improvements in queue management to ensure that projects are removed from the queue if they are not viable, as well as a process to allow commercially viable projects to advance in the queue ahead of projects which have failed to make progress.

The PJM rules for competitive transmission development through the RTEP should build upon FERC Order No. 1000 to create real competition between incumbent transmission providers and merchant transmission providers. The ability of transmission owners to block competition for supplemental projects and end of life projects and any policy reasons for that policy should be reevaluated. PJM should enhance the transparency and queue management process for merchant transmission investment. Issues related to data access and complete explanations of cost impacts should be addressed. The goal should be to remove barriers to competition from merchant transmission. Another element of opening competition would be to consider transmission owners' ownership of property and rights of way at or around transmission substations. In many cases, the land acquired included property intended to support future expansion of the grid. Incumbents have included the costs of the property in their rate base. Because PJM now has the responsibility for planning the development of the grid under its RTEP process, property bought to facilitate future expansion should be a part of the RTEP process and be made available to all providers on equal terms.

There are currently no market incentives for transmission owners to submit and complete transmission outages in a timely and efficient manner. Requiring transmission owners to pay does not create an effective incentive when those payments are passed through to transmission customers. The process for the submission of planned transmission outages needs to be carefully reviewed and redesigned to limit the ability of transmission owners to submit transmission outages that are late for FTR auction bid submission dates and are late for the Day-Ahead Energy Market. The submission of late transmission outages can inappropriately affect market outcomes when market participants do not have the ability to modify market bids and offers.

# Generation Interconnection Planning

## Existing Generation Mix

Table 12-1 shows the existing PJM capacity by control zone and unit type.[10] As of September 30, 2018, PJM had an installed capacity of 195,488.2 MW, of which 57,891.9 MW (29.6 percent) are coal fired steam units, 43,063.1 MW (22.0 percent) are combined cycle units and 34,257.6 MW (17.5 percent) are nuclear units. This measure of installed capacity differs from capacity market installed capacity because it includes energy only units, excludes all external units, and uses nameplate values for solar and wind resources.

The largest zone by total installed capacity is AEP. Of the 195,488.2 MW of PJM installed capacity, 31,343.0 MW (16.0 percent) are in the AEP Zone, of which 14,727.8 MW (47.0 percent) are coal fired steam units, 6,990.0 MW (22.3 percent) are combined cycle units and 2,071.0 MW (6.6 percent) are nuclear units.

Table 12-1 Existing PJM capacity: September 30, 2018 (By zone and unit type (MW))[11]

| Zone | Battery | Combined Cycle | CT - Natural Gas | CT - Oil | CT - Other | Fuel Cell | Hydro - Pumped Storage | Hydro - Run of River | Nuclear | RICE - Natural Gas | RICE - Oil | RICE - Other | Solar | Steam - Coal | Steam - Natural Gas | Steam - Oil | Steam - Other | Wind | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| AECO | 0.0 | 901.9 | 544.7 | 0.0 | 26.0 | 1.6 | 0.0 | 0.0 | 0.0 | 0.0 | 4.0 | 10.6 | 59.4 | 613.9 | 0.0 | 0.0 | 0.0 | 7.5 | 2,169.5 |
| AEP | 6.0 | 6,990.0 | 3,661.2 | 0.0 | 21.0 | 0.0 | 66.0 | 486.9 | 2,071.0 | 0.0 | 0.0 | 20.4 | 14.7 | 14,727.8 | 738.0 | 0.0 | 50.0 | 2,490.0 | 31,343.0 |
| APS | 78.9 | 1,129.0 | 1,223.3 | 0.0 | 2.0 | 0.0 | 0.0 | 129.2 | 0.0 | 0.0 | 29.6 | 18.3 | 55.1 | 5,409.0 | 0.0 | 0.0 | 0.0 | 1,191.5 | 9,265.9 |
| ATSI | 0.0 | 2,150.5 | 958.0 | 0.0 | 659.4 | 0.0 | 0.0 | 0.0 | 2,134.0 | 0.0 | 18.5 | 46.1 | 0.0 | 5,394.0 | 325.0 | 0.0 | 0.0 | 0.0 | 11,685.5 |
| BGE | 0.0 | 0.0 | 500.1 | 0.0 | 267.8 | 0.0 | 0.0 | 0.4 | 1,716.0 | 0.0 | 0.0 | 7.2 | 1.1 | 1,713.0 | 240.5 | 397.0 | 57.0 | 0.0 | 4,900.1 |
| ComEd | 128.5 | 2,621.1 | 6,969.3 | 0.0 | 226.2 | 0.0 | 0.0 | 0.0 | 10,473.5 | 0.0 | 0.0 | 38.3 | 9.0 | 4,124.1 | 1,326.0 | 0.0 | 0.0 | 3,187.9 | 29,103.9 |
| DAY | 0.0 | 0.0 | 1,344.5 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 34.0 | 4.5 | 1.1 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 1,384.1 |
| DEOK | 20.0 | 522.2 | 598.0 | 0.0 | 56.0 | 0.0 | 0.0 | 112.0 | 0.0 | 0.0 | 0.0 | 4.8 | 0.0 | 1,857.0 | 47.0 | 0.0 | 0.0 | 0.0 | 3,217.0 |
| DLCO | 0.0 | 244.0 | 0.0 | 0.0 | 15.0 | 0.0 | 0.0 | 6.3 | 1,777.0 | 0.0 | 0.0 | 0.0 | 0.0 | 565.0 | 0.0 | 0.0 | 0.0 | 0.0 | 2,607.3 |
| Dominion | 0.0 | 7,499.6 | 3,835.3 | 0.0 | 266.4 | 0.0 | 3,003.0 | 586.3 | 3,581.3 | 0.0 | 39.0 | 112.8 | 512.4 | 4,705.6 | 351.0 | 1,586.0 | 368.4 | 208.0 | 26,655.1 |
| DPL | 0.0 | 1,742.5 | 1,298.2 | 0.0 | 478.2 | 30.0 | 0.0 | 0.0 | 0.0 | 0.0 | 88.0 | 14.1 | 213.4 | 410.0 | 882.0 | 153.0 | 0.0 | 0.0 | 5,309.4 |
| EKPC | 0.0 | 0.0 | 774.0 | 0.0 | 0.0 | 0.0 | 0.0 | 70.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 1,687.0 | 0.0 | 0.0 | 0.0 | 0.0 | 2,531.0 |
| JCPL | 0.0 | 2,402.5 | 531.1 | 0.0 | 232.0 | 0.4 | 400.0 | 0.0 | 0.0 | 0.0 | 0.0 | 16.1 | 279.0 | 0.0 | 0.0 | 0.0 | 10.0 | 0.0 | 3,871.1 |
| Met-Ed | 0.0 | 1,616.0 | 2.0 | 0.0 | 398.5 | 0.0 | 0.0 | 19.0 | 805.0 | 0.0 | 0.0 | 33.4 | 0.0 | 115.0 | 0.0 | 0.0 | 60.0 | 0.0 | 3,048.9 |
| PECO | 0.0 | 3,209.0 | 50.8 | 0.0 | 834.0 | 0.0 | 1,070.0 | 572.0 | 4,546.8 | 0.0 | 2.0 | 0.9 | 3.0 | 3.3 | 762.0 | 0.0 | 163.0 | 0.0 | 11,216.8 |
| PENELEC | 28.4 | 850.0 | 350.5 | 0.0 | 57.0 | 0.0 | 513.0 | 77.8 | 0.0 | 0.0 | 106.8 | 17.8 | 0.0 | 6,141.5 | 610.0 | 0.0 | 42.0 | 1,028.8 | 9,823.6 |
| Pepco | 0.0 | 1,710.0 | 764.2 | 0.0 | 308.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 11.1 | 0.0 | 2,433.0 | 1,164.1 | 0.0 | 52.0 | 0.0 | 6,442.4 |
| PPL | 20.0 | 5,064.5 | 252.0 | 0.0 | 150.1 | 0.0 | 0.0 | 706.6 | 2,520.0 | 0.0 | 17.0 | 24.7 | 15.0 | 2,642.9 | 2,449.0 | 10.0 | 29.0 | 216.5 | 14,117.3 |
| PSEG | 5.7 | 4,410.3 | 1,039.2 | 0.0 | 0.0 | 0.0 | 0.0 | 5.0 | 3,493.0 | 0.0 | 0.0 | 6.0 | 195.6 | 0.0 | 3.0 | 0.0 | 188.1 | 0.0 | 9,345.8 |
| XIC | 0.0 | 0.0 | 691.6 | 0.0 | 0.0 | 0.0 | 0.0 | 269.1 | 1,140.0 | 0.0 | 0.0 | 0.0 | 0.0 | 5,349.8 | 0.0 | 0.0 | 0.0 | 0.0 | 7,450.5 |
| Total | 287.5 | 43,063.1 | 25,388.0 | 0.0 | 3,997.6 | 32.0 | 5,052.0 | 3,040.6 | 34,257.6 | 0.0 | 338.9 | 387.0 | 1,358.8 | 57,891.9 | 8,897.6 | 2,146.0 | 1,019.5 | 8,330.2 | 195,488.2 |

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

11 The capacity described in this section refers to all capacity in PJM at the summer installed capacity rating, regardless of whether the capacity entered the RPM Auction. This table previously included external units.

Table 12-2 shows the installed capacity by state for each fuel type. The largest state by total installed capacity is Pennsylvania. Of the 195,488.2 MW of installed capacity, 43,207.6 MW (22.1 percent) are in Pennsylvania, of which 12,112.5 MW (28.0 percent) are combined cycle units, 9,648.8 MW (22.3 percent) are nuclear units and 9,467.7 MW (21.9 percent) are coal fired steam units.

### Table 12-2 Existing PJM capacity: September 30, 2018 (By state and unit type (MW))

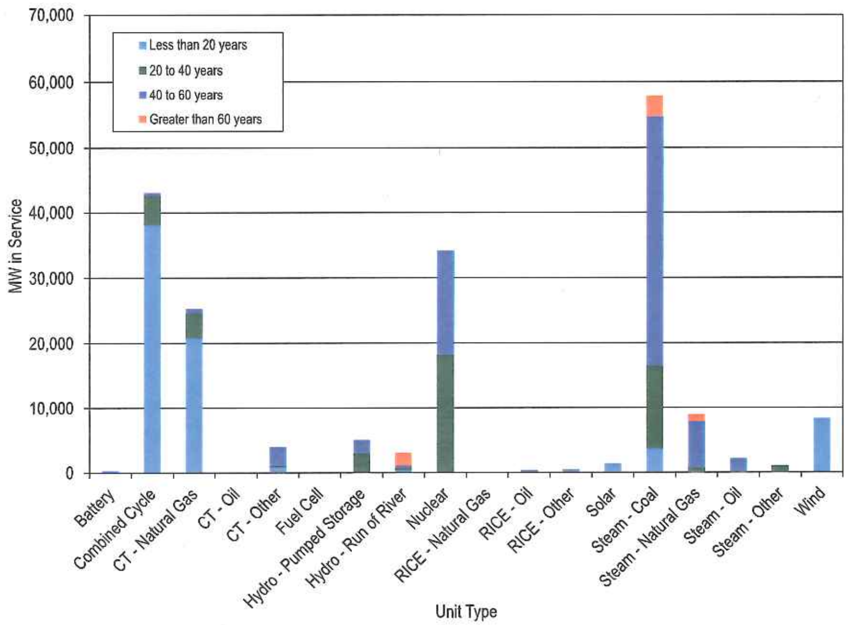
| State | Battery | Combined Cycle | CT - Natural Gas | CT - Oil | CT - Other | Fuel Cell | Hydro - Pumped Storage | Hydro - Run of River | Nuclear | RICE - Natural Gas | RICE - Oil | RICE - Other | Solar | Steam - Coal | Steam - Natural Gas | Steam - Oil | Steam - Other | Wind | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| DE | 0.0 | 742.5 | 325.5 | 0.0 | 116.3 | 30.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 8.1 | 0.0 | 410.0 | 882.0 | 0.0 | 0.0 | 0.0 | 2,514.4 |
| IL | 128.5 | 2,621.1 | 6,969.3 | 0.0 | 226.2 | 0.0 | 0.0 | 0.0 | 10,473.5 | 0.0 | 0.0 | 38.3 | 9.0 | 4,124.1 | 1,326.0 | 0.0 | 0.0 | 3,187.9 | 29,103.9 |
| IN | 0.0 | 1,835.0 | 441.4 | 0.0 | 0.0 | 0.0 | 0.0 | 8.2 | 0.0 | 0.0 | 0.0 | 3.2 | 10.1 | 2,620.0 | 0.0 | 0.0 | 0.0 | 1,823.2 | 6,741.1 |
| KY | 0.0 | 0.0 | 1,618.1 | 0.0 | 0.0 | 0.0 | 0.0 | 136.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 1,687.0 | 278.0 | 0.0 | 0.0 | 0.0 | 3,719.1 |
| MD | 20.0 | 2,710.0 | 2,237.0 | 0.0 | 591.7 | 0.0 | 0.0 | 0.4 | 1,716.0 | 0.0 | 76.0 | 24.3 | 239.6 | 4,386.0 | 1,404.6 | 550.0 | 109.0 | 295.0 | 14,359.6 |
| MI | 0.0 | 1,200.0 | 0.0 | 0.0 | 4.8 | 0.0 | 0.0 | 11.8 | 2,071.0 | 0.0 | 0.0 | 3.2 | 4.6 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 3,295.4 |
| NC | 0.0 | 165.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 315.0 | 0.0 | 0.0 | 18.0 | 0.0 | 277.8 | 115.5 | 0.0 | 0.0 | 0.0 | 208.0 | 1,099.3 |
| NJ | 5.7 | 7,714.7 | 2,115.0 | 0.0 | 258.0 | 2.0 | 400.0 | 5.0 | 3,493.0 | 0.0 | 4.0 | 32.7 | 533.9 | 613.9 | 3.0 | 0.0 | 198.1 | 7.5 | 15,386.5 |
| OH | 24.0 | 6,627.7 | 4,201.2 | 0.0 | 731.6 | 0.0 | 0.0 | 200.0 | 2,134.0 | 0.0 | 52.5 | 55.4 | 1.1 | 12,998.8 | 372.0 | 0.0 | 0.0 | 666.8 | 28,065.1 |
| PA | 48.4 | 12,112.5 | 1,542.7 | 0.0 | 1,454.6 | 0.0 | 1,583.0 | 1,445.7 | 9,648.8 | 0.0 | 155.4 | 95.1 | 18.0 | 9,467.7 | 3,821.0 | 10.0 | 294.0 | 1,510.7 | 43,207.6 |
| TN | 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 | 0.0 | 50.0 | 0.0 | 50.0 |
| VA | 0.0 | 7,334.6 | 4,172.3 | 0.0 | 603.4 | 0.0 | 3,069.0 | 460.1 | 3,581.3 | 0.0 | 33.0 | 118.8 | 264.6 | 3,585.1 | 811.0 | 1,586.0 | 368.4 | 0.0 | 25,987.6 |
| WV | 60.9 | 0.0 | 1,073.9 | 0.0 | 11.0 | 0.0 | 0.0 | 189.3 | 0.0 | 0.0 | 0.0 | 8.0 | 0.0 | 12,534.0 | 0.0 | 0.0 | 0.0 | 631.1 | 14,508.2 |
| XIC | 0.0 | 0.0 | 691.6 | 0.0 | 0.0 | 0.0 | 0.0 | 269.1 | 1,140.0 | 0.0 | 0.0 | 0.0 | 0.0 | 5,349.8 | 0.0 | 0.0 | 0.0 | 0.0 | 7,450.5 |
| Total | 287.5 | 43,063.1 | 25,388.0 | 0.0 | 3,997.6 | 32.0 | 5,052.0 | 3,040.6 | 34,257.6 | 0.0 | 338.9 | 387.0 | 1,358.8 | 57,891.9 | 8,897.6 | 2,146.0 | 1,019.5 | 8,330.2 | 195,488.2 |

Table 12-3 and Figure 12-1 show the age of existing PJM generators, by unit type, as of September 30, 2018. Of the 195,488.2 MW of installed capacity, 76,587.5 MW (39.2 percent) are from units older than 40 years, of which 41,426.7 MW (54.1 percent) are coal fired steam units and 16,044.9 MW (20.9 percent) are nuclear units.

### Table 12-3 PJM capacity (MW) by unit type and age (years): September 30, 2018

| Age (years) | Battery | Combined Cycle | CT - Natural Gas | CT - Oil | CT - Other | Fuel Cell | Hydro - Pumped Storage | Hydro - Run of River | Nuclear | RICE - Natural Gas | RICE - Oil | RICE - Other | Solar | Steam - Coal | Steam - Natural Gas | Steam - Oil | Steam - Other | Wind | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Less than 20 | 287.5 | 38,087.6 | 20,845.2 | 0.0 | 799.0 | 32.0 | 0.0 | 339.2 | 0.0 | 0.0 | 128.4 | 341.6 | 1,358.8 | 3,655.0 | 82.0 | 0.0 | 97.4 | 8,330.2 | 74,383.8 |
| 20 to 40 | 0.0 | 4,443.5 | 3,840.6 | 0.0 | 217.2 | 0.0 | 3,003.0 | 385.2 | 18,212.7 | 0.0 | 37.0 | 45.4 | 0.0 | 12,810.2 | 600.0 | 0.0 | 922.1 | 0.0 | 44,516.9 |
| 40 to 60 | 0.0 | 532.0 | 702.2 | 0.0 | 2,981.4 | 0.0 | 2,049.0 | 340.0 | 16,044.9 | 0.0 | 173.5 | 0.0 | 0.0 | 38,191.4 | 7,131.1 | 2,146.0 | 0.0 | 0.0 | 70,291.5 |
| Greater than 60 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 1,976.2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 3,235.3 | 1,084.5 | 0.0 | 0.0 | 0.0 | 6,296.0 |
| Total | 287.5 | 43,063.1 | 25,388.0 | 0.0 | 3,997.6 | 32.0 | 5,052.0 | 3,040.6 | 34,257.6 | 0.0 | 338.9 | 387.0 | 1,358.8 | 57,891.9 | 8,897.6 | 2,146.0 | 1,019.5 | 8,330.2 | 195,488.2 |

Figure 12-1 PJM capacity (MW) by age (years): September 30, 2018




## Generation Retirements[12]

Generating units generally plan to retire when they are not economic and do not expect to be economic. The MMU performs an analysis of the economics of all units that plan to retire in order to verify that the units are not economic and there is no potential exercise of market power through physical withholding that could advantage the owner's portfolio. The definition of economic is that unit net revenues are greater than or equal to the unit's avoidable or going forward costs.

PJM does not have the authority to order generating plants to continue operating. PJM's responsibility is to ensure system reliability. When a unit retirement creates reliability issues based on existing and planned generation facilities and on existing and planned transmission facilities, PJM identifies transmission solutions.[13]

Rules that preserve the Capacity Injection Rights (CIRs) associated with retired units impose significant costs on new entrants. Currently, CIRs persist for one year if unused, and they can be further extended, at no cost, if assigned to a new project in the interconnection queue at the same point of interconnection.[14] Reforms that require the holders of CIRs to use or lose them, and/or impose costs to holding or transferring them, could make new entry appropriately more attractive. The economic and policy rationale for extending CIRs for inactive units is not clear. Incumbent providers receive a significant advantage simply by imposing on new entrants the entire cost of system upgrades needed to accommodate new entrants. The policy question of whether CIRs should persist after the retirement of a unit should be addressed. Even if the policy treatment of such CIRs remains unchanged, the rules need to ensure that incumbents cannot exploit control of CIRs to block or postpone entry of competitors.

In May 2012, PJM stakeholders (through the Interconnection Process Senior Task Force (IPSTF)) modified the rules to reduce the length of time for which CIRs are retained by the current owner after unit retirements from three years to one.[15] The MMU recognized the progress made in this rule change, but does not believe it fully addressed the issues. The MMU recommends that the question of whether Capacity Injection Rights (CIRs) should persist after the retirement of a unit be addressed. Even if the treatment of CIRs remains unchanged, the rules need to ensure that incumbents cannot exploit control of CIRs to block or postpone entry of competitors.[16]

12 See PJM "Generator Deactivations," at <http://www.pjm.com/planning/services-requests/gen-deactivations.aspx>.

13 See PJM, "Explaining Power Plant Retirements in PJM," at <http://learn.pjm.com/three-priorities/planning-for-the-future/explaining-power-plant-retirements.aspx>.

14 See PJM OATT § 230.3.3.

15 See PJM Interconnection, L.L.C., Docket No. ER12-1177 (Feb. 29, 2012).

16 See "Comments of the Independent Market Monitor for PJM," Docket No. ER12-1177-000 <http://www.monitoringanalytics.com/reports/Reports/2012/IMM_Comments_ER12-1177-000_20120312.pdf>.

## Generation Retirements 2011 through 2021

Table 12-4 shows that there are 43,125.6 MW of generation that have been, or are planned to be, retired between 2011 and 2021, of which 30,821.4 MW (71.5 percent) are coal fired steam units. Coal unit retirements are primarily a result of the inability of coal units to compete with efficient combined cycle units burning low cost gas.

### Table 12-4 Summary of PJM unit retirements by unit type (MW): 2011 through 2021

| | Battery | Combined Cycle | CT - Natural Gas | CT - Oil | CT - Other | Fuel Cell | Hydro - Pumped Storage | Hydro - Run of River | Nuclear | RICE - Natural Gas | RICE - Oil | RICE - Other | Solar | Steam - Coal | Steam - Natural Gas | Steam - Oil | Steam - Other | Wind | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Retirements 2011 | 0.0 | 0.0 | 0.0 | 0.0 | 128.3 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 2.7 | 0.0 | 0.0 | 543.0 | 522.5 | 0.0 | 0.0 | 0.0 | 1,196.5 |
| Retirements 2012 | 0.0 | 0.0 | 250.0 | 0.0 | 240.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 5,907.9 | 0.0 | 548.0 | 16.0 | 0.0 | 6,961.9 |
| Retirements 2013 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 5.9 | 7.0 | 0.0 | 2,589.9 | 82.0 | 166.0 | 8.0 | 0.0 | 2,858.8 |
| Retirements 2014 | 0.0 | 0.0 | 136.0 | 0.0 | 422.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 15.3 | 0.0 | 2,239.0 | 158.0 | 0.0 | 0.0 | 0.0 | 2,970.3 |
| Retirements 2015 | 0.0 | 0.0 | 1,319.0 | 0.0 | 858.2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 10.3 | 0.0 | 0.0 | 7,064.8 | 0.0 | 0.0 | 0.0 | 10.4 | 9,262.7 |
| Retirements 2016 | 0.0 | 0.0 | 0.0 | 0.0 | 71.0 | 0.0 | 0.5 | 0.0 | 0.0 | 0.0 | 8.0 | 3.9 | 0.0 | 243.0 | 74.0 | 0.0 | 0.0 | 0.0 | 400.4 |
| Retirements 2017 | 40.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.8 | 0.0 | 2,038.0 | 34.0 | 0.0 | 0.0 | 0.0 | 2,112.8 |
| Retirements 2018 | 1.0 | 425.0 | 0.0 | 0.0 | 39.6 | 0.0 | 0.0 | 0.0 | 614.5 | 0.0 | 17.2 | 6.9 | 0.0 | 2,854.0 | 680.0 | 148.0 | 108.0 | 0.0 | 4,894.2 |
| Planned Retirements (November 2018 and later) | 0.0 | 0.0 | 50.8 | 0.0 | 30.4 | 0.0 | 0.0 | 0.0 | 4,716.0 | 0.0 | 13.0 | 0.0 | 0.0 | 7,341.8 | 316.0 | 0.0 | 0.0 | 0.0 | 12,468.0 |
| Total | 41.0 | 425.0 | 1,755.8 | 0.0 | 1,789.5 | 0.0 | 0.5 | 0.0 | 5,330.5 | 0.0 | 57.1 | 33.9 | 0.0 | 30,821.4 | 1,866.5 | 862.0 | 132.0 | 10.4 | 43,125.6 |

Table 12-5 shows the capacity, average size, and average age of units retiring in PJM, from 2011 through 2021, while Table 12-6 shows these retirements by state. Of the 43,125.6 MW of units that has been, or are planned to be, retired between 2011 and 2021, 30,821.4 MW (71.5 percent) are coal fired steam units. These coal fired steam units have an average age of 53.0 years and an average size of 192.6 MW. Over half of the retiring coal fired steam units, 57.8 percent, are located in either Ohio or Pennsylvania. Retirements have generally consisted of smaller subcritical coal fired steam units and those without adequate environmental controls to remain viable in the future.

## Table 12-5 Retirements by unit type: 2011 through 2021

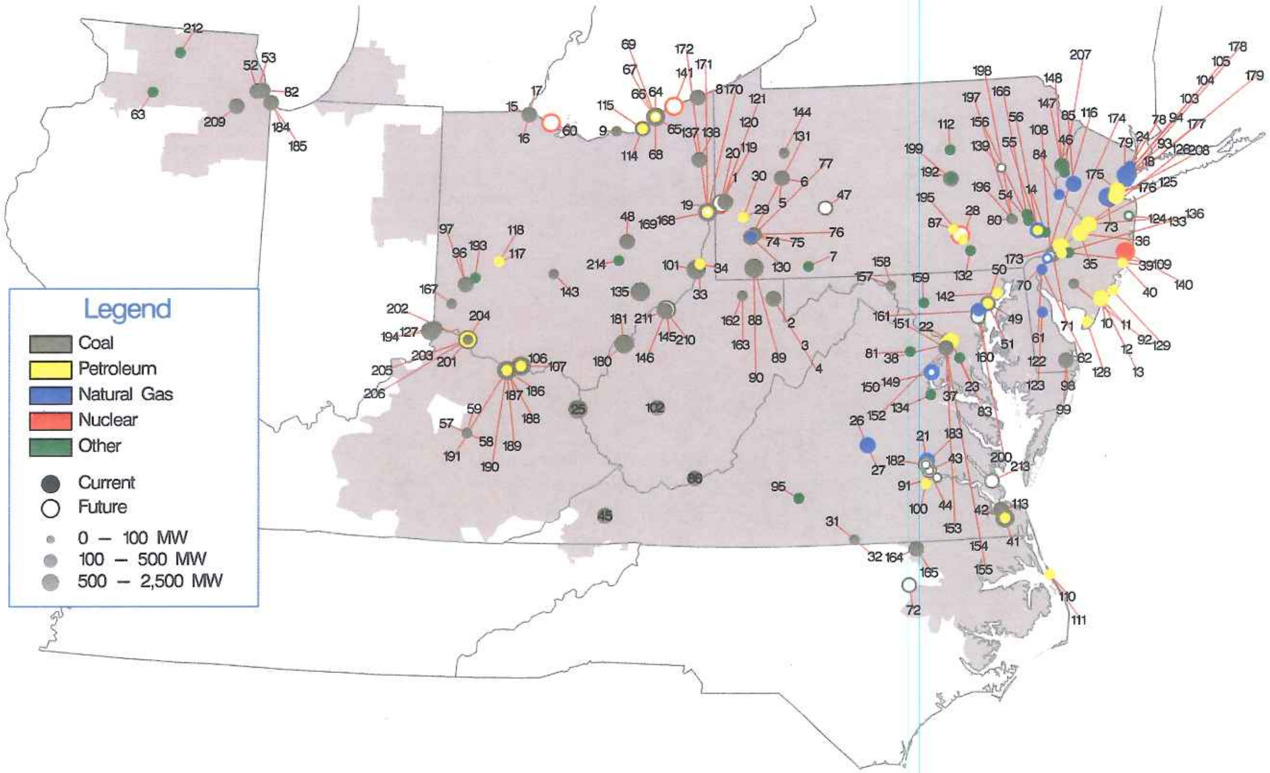
| Unit Type | Number of Units | Avg. Size (MW) | Avg. Age at Retirement (Years) | Total MW | Percent |
|---|---|---|---|---|---|
| Battery | 2 | 20.5 | 7.0 | 41.0 | 0.1% |
| Combined Cycle | 2 | 212.5 | 25.5 | 425.0 | 1.0% |
| Combustion Turbine | 92 | 38.8 | 42.7 | 3,545.3 | 8.2% |
| Natural Gas | 42 | 41.8 | 43.7 | 1,755.8 | 4.1% |
| Oil | 0 | 0.0 | 0.0 | 0.0 | 0.0% |
| Other | 50 | 35.8 | 41.6 | 1,789.5 | 4.1% |
| Fuel Cell | 0 | 0.0 | 0.0 | 0.0 | 0.0% |
| Hydro | 1 | 0.5 | 113.8 | 0.5 | 0.0% |
| Pumped Storage | 1 | 0.5 | 113.8 | 0.5 | 0.0% |
| Run of River | 0 | 0.0 | 0.0 | 0.0 | 0.0% |
| Nuclear | 6 | 888.4 | 41.6 | 5,330.5 | 12.4% |
| RICE | 21 | 4.3 | 28.4 | 91.0 | 0.2% |
| Natural Gas | 0 | 0.0 | 0.0 | 0.0 | 0.0% |
| Oil | 11 | 5.2 | 46.1 | 57.1 | 0.1% |
| Other | 10 | 3.4 | 10.6 | 33.9 | 0.1% |
| Solar | 0 | 0.0 | 0.0 | 0.0 | 0.0% |
| Steam | 184 | 139.5 | 44.9 | 33,681.9 | 78.1% |
| Coal | 160 | 192.6 | 53.0 | 30,821.4 | 71.5% |
| Natural Gas | 16 | 116.7 | 61.3 | 1,866.5 | 4.3% |
| Oil | 4 | 215.5 | 45.5 | 862.0 | 2.0% |
| Other | 4 | 33.0 | 19.8 | 132.0 | 0.3% |
| Wind | 1 | 10.4 | 15.6 | 10.4 | 0.0% |
| Total | 309 | 139.6 | 47.5 | 43,125.6 | 100.0% |

## Table 12-6 Retirements (MW) by unit type and state: 2011 through 2021

| State | Battery | Combined Cycle | CT - Natural Gas | CT - Oil | CT - Other | Fuel Cell | Hydro - Pumped Storage | Hydro - Run of River | Nuclear | RICE - Natural Gas | RICE - Oil | RICE - Other | Solar | Steam - Coal | Steam - Natural Gas | Steam - Oil | Steam - Other | Wind | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| DC | 0.0 | 0.0 | 0.0 | 0.0 | 240.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 548.0 | 0.0 | 0.0 | 788.0 |
| DE | 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 | 254.0 | 34.0 | 0.0 | 0.0 | 0.0 | 288.0 |
| IL | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 12.5 | 0.0 | 1,624.0 | 0.0 | 0.0 | 0.0 | 0.0 | 1,636.5 |
| IN | 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 | 982.0 | 0.0 | 0.0 | 0.0 | 0.0 | 982.0 |
| KY | 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 | 995.0 | 0.0 | 0.0 | 0.0 | 0.0 | 995.0 |
| MD | 0.0 | 0.0 | 115.0 | 0.0 | 66.6 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.8 | 0.0 | 635.0 | 74.0 | 0.0 | 0.0 | 0.0 | 891.4 |
| NC | 0.0 | 0.0 | 0.0 | 0.0 | 31.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 324.5 | 0.0 | 0.0 | 0.0 | 0.0 | 355.5 |
| NJ | 0.0 | 158.0 | 1,590.0 | 0.0 | 1,046.6 | 0.0 | 0.5 | 0.0 | 614.5 | 0.0 | 8.0 | 9.8 | 0.0 | 1,543.0 | 932.5 | 148.0 | 0.0 | 0.0 | 6,050.9 |
| OH | 40.0 | 0.0 | 0.0 | 0.0 | 286.0 | 0.0 | 0.0 | 0.0 | 2,134.0 | 0.0 | 32.3 | 0.9 | 0.0 | 13,092.6 | 0.0 | 0.0 | 0.0 | 0.0 | 15,585.8 |
| PA | 1.0 | 0.0 | 50.8 | 0.0 | 52.0 | 0.0 | 0.0 | 0.0 | 2,582.0 | 0.0 | 13.9 | 8.0 | 0.0 | 4,713.3 | 283.0 | 166.0 | 49.0 | 10.4 | 7,929.4 |
| VA | 0.0 | 267.0 | 0.0 | 0.0 | 67.3 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 2.9 | 2.0 | 0.0 | 2,739.0 | 543.0 | 0.0 | 83.0 | 0.0 | 3,704.2 |
| WV | 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 | 3,919.0 | 0.0 | 0.0 | 0.0 | 0.0 | 3,919.0 |
| Total | 41.0 | 425.0 | 1,755.8 | 0.0 | 1,789.5 | 0.0 | 0.5 | 0.0 | 5,330.5 | 0.0 | 57.1 | 33.9 | 0.0 | 30,821.4 | 1,866.5 | 862.0 | 132.0 | 10.4 | 43,125.6 |

A map of unit retirements between 2011 and 2021 is shown in Figure 12-2 with a mapping to unit names identified in Table 12-7.

Figure 12-2 Map of PJM unit retirements: 2011 through 2021



## Table 12-7 Unit identification for map of PJM unit retirements: 2011 through 2021

| ID | Unit | ID | Unit | ID | Unit | ID | Unit | ID | Unit | ID | Unit | ID | Unit |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | AES Beaver Valley | 36 | Burlington 9 | 71 | Eddystone 2 | 106 | Killen 2 | 141 | Perry U1 Nuclear Generating Unit | 176 | Sewaren 2 | 211 | Willow Island 2 |
| 2 | Albright 1 | 37 | Buzzard Point East Banks 1,2,4-8 | 72 | Edgecomb NUG (Rocky 1-2) | 107 | Killen CT | 142 | Perryman 2 | 177 | Sewaren 3 | 212 | Winnebago Landfill |
| 3 | Albright 2 | 38 | Buzzard Point West Banks 1-9 | 73 | Edison 1-3 | 108 | Kimberly Clark Generator | 143 | Picway 5 | 178 | Sewaren 4 | 213 | Yorktown 1-2 |
| 4 | Albright 3 | 39 | Cedar 1 | 74 | Elrama 1 | 109 | Kinsley Landfill | 144 | Piney Creek NUG | 179 | Sewaren 6 | 214 | Zanesville Landfill |
| 5 | Armstrong 1 | 40 | Cedar 2 | 75 | Elrama 2 | 110 | Kitty Hawk GT 1 | 145 | Pleasants Power Station U1 | 180 | Sporn 1-4 | | |
| 6 | Armstrong 2 | 41 | Chesapeake 1-4 | 76 | Elrama 3 | 111 | Kitty Hawk GT 2 | 146 | Pleasants Power Station U2 | 181 | Sporn 5 | | |
| 7 | Arnold (Green Mtn. Wind Farm | 42 | Chesapeake 7-10 | 77 | Elrama 4 | 112 | Koppers Co. IPP | 147 | Portland 1 | 182 | Spruance NUG1 (Rich 1-2) | | |
| 8 | Ashtabula 5 | 43 | Chesterfield 3 | 78 | Essex 10-11 | 113 | Lake Kingman | 148 | Portland 2 | 183 | Spruance NUG2 (Rich 3-4) | | |
| 9 | Avon Lake 7 | 44 | Chesterfield 4 | 79 | Essex 12 | 114 | Lake Shore 18 | 149 | Possum Point 3 | 184 | State Line 3 | | |
| 10 | BL England 1 | 45 | Clinch River 3 | 80 | Evergreen Power United Corstack | 115 | Lake Shore EMD | 150 | Possum Point 4 | 185 | State Line 4 | | |
| 11 | BL England 2 | 46 | Columbia Dam Hydro | 81 | Fauquier County Landfill | 116 | MH50 Markus Hook Co-gen | 151 | Potomac River 1 | 186 | Stuart 1 | | |
| 12 | BL England 3 | 47 | Colver Power Project | 82 | Fisk Street 19 | 117 | Mad River CTs A | 152 | Potomac River 2 | 187 | Stuart 2 | | |
| 13 | BL England Diesel Units 1-4 | 48 | Conesville 3 | 83 | GUDE Landfill | 118 | Mad River CTs B | 153 | Potomac River 3 | 188 | Stuart 3 | | |
| 14 | Barbados AES Battery | 49 | Crane 1 | 84 | Gilbert 1-4 | 119 | Mansfield 1 | 154 | Potomac River 4 | 189 | Stuart 4 | | |
| 15 | Bay Shore 2 | 50 | Crane 2 | 85 | Glen Gardner 1-8 | 120 | Mansfield 2 | 155 | Potomac River 5 | 190 | Stuart Diesels 1-4 | | |
| 16 | Bay Shore 3 | 51 | Crane GT1 | 86 | Glen Lyn 5-6 | 121 | Mansfield 3 | 156 | Pottstown LF (Moser) | 191 | Stuart Diesels 1-4 | | |
| 17 | Bay Shore 4 | 52 | Crawford 7 | 87 | Harrisburg 4 CT | 122 | McKee 1 | 157 | R Paul Smith 3 | 192 | Sunbury 1-4 | | |
| 18 | Bayonne Cogen Plant (CC) | 53 | Crawford 8 | 88 | Hatfield's Ferry 1 | 123 | McKee 2 | 158 | R Paul Smith 4 | 193 | Tait Battery | | |
| 19 | Beaver Valley U1 Nuclear Generating Unit | 54 | Cromby 1 | 89 | Hatfield's Ferry 2 | 124 | Mercer 1 | 159 | Reichs Ford Road Landfill Generator | 194 | Tanners Creek 1-4 | | |
| 20 | Beaver Valley U2 Nuclear Generating Unit | 55 | Cromby 2 | 90 | Hatfield's Ferry 3 | 125 | Mercer 2 | 160 | Riverside 4 | 195 | Three Mile Island Unit 1 | | |
| 21 | Bellemeade | 56 | Cromby D | 91 | Hopewell James River Cogeneration | 126 | Mercer 3 | 161 | Riverside 6 | 196 | Titus 1 | | |
| 22 | Benning 15 | 57 | Dale 1-2 | 92 | Howard Down 10 | 127 | Miami Fort 6 | 162 | Riversville 5 | 197 | Titus 2 | | |
| 23 | Benning 16 | 58 | Dale 3 | 93 | Hudson 1 | 128 | Middle 1-3 | 163 | Riversville 6 | 198 | Titus 3 | | |
| 24 | Bergen 3 | 59 | Dale 4 | 94 | Hudson 2 | 129 | Missouri Ave B,C,D | 164 | Roanoke Valley 1 | 199 | Viking Energy NUG | | |
| 25 | Big Sandy 2 | 60 | Davis Besse U1 Nuclear Generating Unit | 95 | Hurt NUG | 130 | Mitchell 2 | 165 | Roanoke Valley 2 | 200 | Wagner 2 | | |
| 26 | Bremo 3 | 61 | Deepwater 1 | 96 | Hutchings 1-3, 5-6 | 131 | Mitchell 3 | 166 | Rolling Hills Landfill Generator | 201 | Walter C Beckjord 1 | | |
| 27 | Bremo 4 | 62 | Deepwater 6 | 97 | Hutchings 4 | 132 | Modern Power Landfill NUG | 167 | SMART Paper | 202 | Walter C Beckjord 2 | | |
| 28 | Brunner Island Diesels | 63 | Dixon Lee Landfill Generator | 98 | Indian River 1 | 133 | Monmouth NUG landfill | 168 | Sammis 1-4 | 203 | Walter C Beckjord 3 | | |
| 29 | Brunot Island 1B | 64 | Eastlake 1 | 99 | Indian River 3 | 134 | Morris Landfill Generator | 169 | Sammis 5 | 204 | Walter C Beckjord 4 | | |
| 30 | Brunot Island 1C | 65 | Eastlake 2 | 100 | Ingenco Petersburg | 135 | Muskingum River 1-5 | 170 | Sammis 6 | 205 | Walter C Beckjord 5-6 | | |
| 31 | Buggs Island 1 (Mecklenberg) | 66 | Eastlake 3 | 101 | Kammer 1-3 | 136 | National Park 1 | 171 | Sammis 7 | 206 | Walter C Beckjord GT 1-4 | | |
| 32 | Buggs Island 2 (Mecklenberg) | 67 | Eastlake 4 | 102 | Kanawha River 1-2 | 137 | Niles 1 | 172 | Sammis Diesel | 207 | Warren County Landfill | | |
| 33 | Burger 3 | 68 | Eastlake 5 | 103 | Kearny 10 | 138 | Niles 2 | 173 | Schuylkill 1 | 208 | Werner 1-4 | | |
| 34 | Burger EMD | 69 | Eastlake 6 | 104 | Kearny 11 | 139 | Northeastern Power NEPCO | 174 | Schuylkill Diesel | 209 | Will County 3 | | |
| 35 | Burlington 8,11 | 70 | Eddystone 1 | 105 | Kearny 9 | 140 | Oyster Creek | 175 | Sewaren 1 | 210 | Willow Island 1 | | |

## Current Year Generation Retirements

Table 12-8 shows that in the first nine months of 2018, 4,894.2 MW of generation retired. The largest generator that retired in first nine months of 2018 was the joint owned 600 MW Killen 2 unit (402 MW owned by AES Corporation and 198 MW owned by Vistra Energy Corporation) located in the Dayton Power and Light (DAY) Zone. Of the 4,894.2 MW of generation that retired, 2,364.0 MW (48.3 percent) were located in the DAY Zone.

### Table 12-8 Unit deactivations: January through September, 2018[17]

| Company | Unit Name | ICAP (MW) | Unit Type | Zone Name | Age (Years) | Retirement Date |
|---|---|---|---|---|---|---|
| Biogas Energy Solutions, LLC | Dixon Lee Landfill Generator | 4.0 | RICE-Other | ComEd | 4.8 | 10-Jan-18 |
| Rockland Capital Energy Investments, LLC | BL England 3 | 148.0 | Steam-Oil | AECO | 43.2 | 24-Jan-18 |
| Riverstone Holdings LLC | Brunner Island Diesels | 8.2 | RICE-Oil | PPL | 50.8 | 25-Feb-18 |
| Dominion Resources, Inc. | Buggs Island 1 (Mecklenberg) | 69.0 | Steam-Coal | Dominion | 25.5 | 09-Apr-18 |
| Dominion Resources, Inc. | Buggs Island 2 (Mecklenberg) | 69.0 | Steam-Coal | Dominion | 25.5 | 09-Apr-18 |
| Dominion Resources, Inc. | Bellemeade | 267.0 | Combined Cycle | Dominion | 21.2 | 16-Apr-18 |
| Dominion Resources, Inc. | Bremo 3 | 71.0 | Steam-Natural Gas | Dominion | 67.9 | 16-Apr-18 |
| Dominion Resources, Inc. | Bremo 4 | 156.0 | Steam-Natural Gas | Dominion | 59.7 | 16-Apr-18 |
| Evergreen Community Power LLC | Evergreen Power United Corstack | 25.0 | Steam-Biomass | Met-Ed | 8.7 | 01-May-18 |
| Biogas Energy Solutions, LLC | Morris Landfill Generator | 2.1 | RICE-Other | ComEd | 5.0 | 31-May-18 |
| South Jersey Industries, Inc. | Reichs Ford Road Landfill Generator | 1.6 | CT-Other | APS | 8.1 | 31-May-18 |
| American Electric Power Company, Inc. | Stuart 2 | 150.0 | Steam-Coal | DAY | 47.7 | 01-Jun-18 |
| American Electric Power Company, Inc. | Stuart 3 | 150.0 | Steam-Coal | DAY | 46.1 | 01-Jun-18 |
| American Electric Power Company, Inc. | Stuart 4 | 150.0 | Steam-Coal | DAY | 44.0 | 01-Jun-18 |
| American Electric Power Company, Inc. | Stuart Diesels 1-4 | 2.4 | RICE-Oil | DAY | 48.7 | 01-Jun-18 |
| Avenue Capital Group LLC | Crane 1 | 190.0 | Steam-Coal | BGE | 57.0 | 01-Jun-18 |
| Avenue Capital Group LLC | Crane 2 | 195.0 | Steam-Coal | BGE | 55.4 | 01-Jun-18 |
| Avenue Capital Group LLC | Crane GT1 | 14.0 | CT-Other | BGE | 50.9 | 01-Jun-18 |
| Riverstone Holdings LLC | Bayonne Cogen Plant (CC) | 158.0 | Combined Cycle | PSEG | 29.7 | 01-Jun-18 |
| The AES Corporation | Killen 2 | 402.0 | Steam-Coal | DAY | 36.0 | 01-Jun-18 |
| The AES Corporation | Killen CT | 18.0 | CT-Other | DAY | 35.2 | 01-Jun-18 |
| The AES Corporation | Stuart 2 | 202.0 | Steam-Coal | DAY | 47.7 | 01-Jun-18 |
| The AES Corporation | Stuart 3 | 202.0 | Steam-Coal | DAY | 46.1 | 01-Jun-18 |
| The AES Corporation | Stuart 4 | 202.0 | Steam-Coal | DAY | 44.0 | 01-Jun-18 |
| The AES Corporation | Stuart Diesels 1-4 | 3.0 | RICE-Oil | DAY | 48.7 | 01-Jun-18 |
| Vistra Energy Corp | Killen 2 | 198.0 | Steam-Coal | DAY | 36.0 | 01-Jun-18 |
| Vistra Energy Corp | Killen CT | 6.0 | CT-Other | DAY | 35.2 | 01-Jun-18 |
| Vistra Energy Corp | Stuart 2 | 225.0 | Steam-Coal | DAY | 47.7 | 01-Jun-18 |
| Vistra Energy Corp | Stuart 3 | 225.0 | Steam-Coal | DAY | 46.1 | 01-Jun-18 |
| Vistra Energy Corp | Stuart 4 | 225.0 | Steam-Coal | DAY | 44.0 | 01-Jun-18 |
| Vistra Energy Corp | Stuart Diesels 1-4 | 3.6 | RICE-Oil | DAY | 48.7 | 01-Jun-18 |
| Public Service Enterprise Group Incorporated | Sewaren 1 | 104.0 | Steam-Natural Gas | PSEG | 69.6 | 06-Jun-18 |
| Public Service Enterprise Group Incorporated | Sewaren 2 | 118.0 | Steam-Natural Gas | PSEG | 69.6 | 06-Jun-18 |
| Public Service Enterprise Group Incorporated | Sewaren 3 | 107.0 | Steam-Natural Gas | PSEG | 68.7 | 06-Jun-18 |
| Public Service Enterprise Group Incorporated | Sewaren 4 | 124.0 | Steam-Natural Gas | PSEG | 67.0 | 06-Jun-18 |
| Dominion Resources, Inc. | Hurt NUG | 83.0 | Steam-Biomass | Dominion | 24.2 | 24-Jul-18 |
| The AES Corporation | Barbados AES Battery | 1.0 | Battery | PECO | 9.7 | 29-Jul-18 |
| Quasar Energy Group, LLC | Zanesville Landfill | 0.9 | RICE-Other | AEP | 6.1 | 08-Sep-18 |
| Exelon Corporation | Oyster Creek Nuclear Generating Station | 614.5 | Nuclear | JCPL | 48.8 | 17-Sep-18 |
| Total | | 4,894.2 | | | | |

17 The Killen 2, Killen CT, Stuart 2, 3 and 4 and Stuart Diesels 1-4 units are jointly owned. The MW displayed in each row represents the individual company's share of the retiring unit.

## Planned Generation Retirements

Table 12-9 shows that there are 12,468.0 MW of generation that have requested retirement after September 30, 2018, of which 6,791.0 MW (54.5 percent) are located in the ATSI Zone, 7,341.8 MW (58.9 percent) are coal fired steam units and 4,716.0 MW (37.8 percent) are nuclear units. The largest generator pending retirement is the 1,240 MW Perry U1 Nuclear Generating Unit located in the ATSI Zone.

### Table 12-9 Planned retirement of PJM units: September 30, 2018

| Unit | Zone | ICAP (MW) | Unit Type | Projected Deactivation Date |
|---|---|---|---|---|
| Northeastern Power NEPCO | PPL | 52.0 | Steam-Coal | 27-Nov-18 |
| Chesterfield 3 | Dominion | 97.5 | Steam-Coal | 01-Dec-18 |
| Chesterfield 4 | Dominion | 163.0 | Steam-Coal | 01-Dec-18 |
| Possum Point 3 | Dominion | 96.0 | Steam-Natural Gas | 01-Dec-18 |
| Possum Point 4 | Dominion | 220.0 | Steam-Natural Gas | 01-Dec-18 |
| Yorktown 1-2 | Dominion | 323.0 | Steam-Coal | 08-Dec-18 |
| Pleasants Power Station U1 | APS | 639.0 | Steam-Coal | 01-Jan-19 |
| Pleasants Power Station U2 | APS | 639.0 | Steam-Coal | 01-Jan-19 |
| Spruance NUG1 (aka Spruance 1 Rich 1-2) | Dominion | 115.5 | Steam-Coal | 12-Jan-19 |
| Spruance NUG2 (aka Spruance 2 Rich 3-4) | Dominion | 85.0 | Steam-Coal | 12-Jan-19 |
| Hopewell James River Cogeneration | Dominion | 89.0 | Steam-Coal | 31-Mar-19 |
| BL England 2 | AECO | 155.0 | Steam-Coal | 30-Apr-19 |
| Monmouth NUG landfill | JCPL | 6.4 | CT-Other | 31-May-19 |
| MH50 Markus Hook Co-gen | PECO | 50.8 | CT-Natural_Gas | 01-Jun-19 |
| Kimberly Clark Generator | PECO | 3.3 | Steam-Coal | 01-Aug-19 |
| Three Mile Island Unit 1 Nuclear Generating Station | Met-Ed | 805.0 | Nuclear | 30-Sep-19 |
| Davis Besse U1 Nuclear Generating Unit | ATSI | 894.0 | Nuclear | 31-May-20 |
| Sammis 1-4 | ATSI | 640.0 | Steam-Coal | 31-May-20 |
| Wagner 2 | BGE | 135.0 | Steam-Coal | 01-Jun-20 |
| Colver Power Project | PENELEC | 110.0 | Steam-Coal | 01-Sep-20 |
| Edgecomb NUG (aka Edgecomb Rocky 1-2) | Dominion | 115.5 | Steam-Coal | 31-Oct-20 |
| Perry U1 Nuclear Generating Unit | ATSI | 1,240.0 | Nuclear | 31-May-21 |
| Beaver Valley U1 Nuclear Generating Unit | DLCO | 892.0 | Nuclear | 31-May-21 |
| Eastlake 6 | ATSI | 24.0 | CT-Other | 01-Jun-21 |
| Sammis Diesel | ATSI | 13.0 | RICE-Oil | 01-Jun-21 |
| Mansfield 1 | ATSI | 830.0 | Steam-Coal | 01-Jun-21 |
| Mansfield 2 | ATSI | 830.0 | Steam-Coal | 01-Jun-21 |
| Mansfield 3 | ATSI | 830.0 | Steam-Coal | 01-Jun-21 |
| Beaver Valley U2 Nuclear Generating Unit | DLCO | 885.0 | Nuclear | 31-Oct-21 |
| Sammis 5 | ATSI | 290.0 | Steam-Coal | 01-Jun-22 |
| Sammis 6 | ATSI | 600.0 | Steam-Coal | 01-Jun-22 |
| Sammis 7 | ATSI | 600.0 | Steam-Coal | 01-Jun-22 |
| Total | | 12,468.0 | | |

## Generation Queue

Any entity that requests interconnection of a new generating facility, including increases to the capacity of an existing generating unit, or that requests interconnection of a merchant transmission facility, must follow the process defined in the PJM tariff to obtain interconnection service.[18] PJM's process is designed to ensure that new generation is added in a reliable and systematic manner. The process is complex and time consuming at least in part as a result of the required analyses. The cost, time and uncertainty associated with interconnecting to the grid may create barriers to entry for potential entrants. The MMU recommends that barriers to entry be addressed in a timely manner in order to help ensure that the market will result in the entry of new capacity to meet the needs of PJM market participants.

Generation request queues are groups of proposed projects, including new units, reratings of existing units, capacity resources and energy only resources. Each queue is open for a fixed amount of time. Studies commence on all projects in a given queue when that queue closes. Queues A and B were open for a year. Queues C through T were open for six months. Starting in February 2008, Queues U through Y1 were open for three months. In May 2012, the duration of the queue period was reset to six months, starting with Queue Y2. Queue AD2 began on October 1, 2017 and closed on March 31, 2018. Queue AE1 began on April 1, 2018 and closed on September 30, 2018.

Projects that do not meet submission requirements are removed from the queue. All projects that have been entered in a queue and have met the submission requirements have a status assigned. Projects listed as active are undergoing one of the studies (feasibility, system impact, facility) required to proceed. Other status options are under construction, suspended, and in service. A project cannot be suspended until it has reached the status of under construction. Any project that entered the queue before February 1, 2011, can be suspended for up to three years. Projects that entered the queue after February 1, 2011, face an additional restriction in that the suspension period is reduced to one year if they affect any project later in the queue.[19] When a project is suspended, PJM extends the scheduled milestones by the duration of the suspension. If, at any time, a milestone is not met, PJM will initiate the termination of the Interconnection Service Agreement (ISA) and the corresponding cancellation costs must be paid by the customer.[20]

The PJM queue evaluation process has been substantially improved in recent years and it is more efficient and effective as a result.[21] The PJM queue evaluation process should continue to be improved to help ensure that barriers to competition from new generation investments are not created. The MMU recommends improvements in queue management including that PJM establish a review process to ensure that projects are removed from the queue if they are not viable, as well as a process to allow commercially viable projects to advance in the queue ahead of projects which have failed to make progress, subject to rules to prevent gaming.

## Process Timelines

In the study phase of the interconnection planning process, a series of studies are performed to determine the feasibility, impact, and cost of projects in the queue. Table 12-10 is an overview of PJM's study process. System impact and facilities studies are often redone when a project is withdrawn in order to determine the impact on the projects remaining in the queue.

18 See OATT Parts IV & VI.
19 See "PJM Manual 14C: Generation and Transmission Interconnection Process," Rev. 13 (August 23, 2018) Section 3.7
20 PJM does not track the duration of suspensions or PJM termination of projects.
21 See PJM Interconnection, LLC, Docket No. ER12-1177 (Feb. 29, 2012).

In 2016, the PJM Earlier Queue Submitted Task Force stakeholder group made changes to the interconnection process to address some of the issues related to delays observed in the various stages of the study phase. The changes became effective with the AC2 Queue that closed on March 31, 2017. Until there has been additional time and queue processing to validate the effectiveness of these changes, the MMU recommends continuing analysis of the study phase of PJM's transmission planning to reduce the need for postponements of study results, to decrease study completion times, and to improve the likelihood that a project at a given phase in the study process will successfully go into service.

Table 12-10 PJM generation planning process

| Process Step | Start on | Financial Obligation | Days for PJM to Complete | Days for Applicant to Decide Whether to Continue |
|---|---|---|---|---|
| Feasibility Study | Close of current queue | Cost of study (partially refundable deposit) | 90 | 30 |
| System Impact Study | Upon acceptance of the System Impact Study Agreement | Cost of study (partially refundable deposit) | 120 | 30 |
| Facilities Study | Upon acceptance of the Facilities Study Agreement | Cost of study (refundable deposit) | Varies | 60 |
| Schedule of Work | Upon acceptance of Interconnection Service Agreement (ISA) | Letter of credit for upgrade costs | Varies | 37 |
| Construction (only for new generation) | Upon acceptance of Interconnection Construction Service Agreement (ICSA) | None | Varies | NA |

## Planned Generation Additions

Expected net revenues provide incentives to build new generation to serve PJM markets. The amount of planned new generation in PJM reflects investors' perception of the incentives provided by the combination of revenues from the PJM energy, capacity and ancillary service markets. On September 30, 2018, 101,393.4 MW of capacity were in generation request queues for construction through 2029. Although it is clear that not all generation in the queues will be built, PJM has added capacity steadily since markets were implemented on April 1, 1999.[22]

Table 12-11 shows MW in queues by expected completion year and MW changes in the queue between December 31, 2017, and September 30, 2018, for ongoing projects, i.e. projects with the status active, under construction or suspended.[23] Projects that are already in service are not included here. Projects that have been withdrawn or removed from the queue are no longer included in the totals. The total MW in queues increased by 22,169.1 MW (28.0 percent) from 79,224.3 MW at the end of 2017 to 101,393.4 MW on September 30, 2018.

22 See Monitoring Analytics, "New Generation in the PJM Capacity Market: MW and Funding Sources for Delivery Years 2007/2008 through 2018/2019," <http://www.monitoringanalytics.com/reports/Reports/2016/New_Generation_in_the_PJM_Capacity_Market_20160504.pdf>.

23 Expected completion dates are entered when the project enters the queue. Actual completion dates are generally different than expected completion dates.

**Table 12-11 Queue comparison by expected completion year (MW): December 31, 2017 and September 30, 2018[24]**

| | | | Year Change | |
|---|---|---|---|---|
| Year | As of 12/31/2017 | As of 9/30/2018 | MW | Percent |
| 2008 | 12.0 | 12.0 | 0.0 | 0.0% |
| 2009 | 0.0 | 0.0 | 0.0 | 0.0% |
| 2010 | 0.0 | 0.0 | 0.0 | 0.0% |
| 2011 | 102.5 | 102.5 | 0.0 | 0.0% |
| 2012 | 91.2 | 91.2 | 0.0 | 0.0% |
| 2013 | 210.5 | 210.5 | 0.0 | 0.0% |
| 2014 | 27.4 | 12.4 | (15.0) | (54.7%) |
| 2015 | 502.4 | 234.1 | (268.3) | (53.4%) |
| 2016 | 2,067.4 | 967.2 | (1,100.2) | (53.2%) |
| 2017 | 4,342.9 | 3,038.3 | (1,304.5) | (30.0%) |
| 2018 | 13,489.2 | 10,564.6 | (2,924.6) | (21.7%) |
| 2019 | 24,330.0 | 25,758.0 | 1,428.0 | 5.9% |
| 2020 | 23,235.6 | 28,947.8 | 5,712.1 | 24.6% |
| 2021 | 8,352.4 | 19,704.7 | 11,352.3 | 135.9% |
| 2022 | 2,460.9 | 4,265.9 | 1,805.0 | 73.3% |
| 2023 | 0.0 | 3,764.0 | 3,764.0 | 0.0% |
| 2024 | 0.0 | 1,320.0 | 1,320.0 | 0.0% |
| 2025 | 0.0 | 800.1 | 800.1 | 0.0% |
| 2026 | 0.0 | 0.0 | 0.0 | 0.0% |
| 2027 | 0.0 | 800.1 | 800.1 | 0.0% |
| 2028 | 0.0 | 0.0 | 0.0 | 0.0% |
| 2029 | 0.0 | 800.1 | 800.1 | 0.0% |
| Total | 79,224.3 | 101,393.4 | 22,169.1 | 28.0% |

Table 12-12 shows the project status changes in more detail and how scheduled queue capacity has changed between December 31, 2017, and September 30, 2018. For example, 29,541.3 MW entered the queue in the first nine months of 2018. Of those 29,541.3 MW, 7,372.3 MW have been withdrawn. Of the total 71,405.5 MW marked as active on December 31, 2017, 10,752.6 MW were withdrawn, 3,018.8 MW were suspended, 844.2 MW started construction, and 221.7 MW went into service by September 30, 2018. Analysis of projects that were suspended on December 31, 2017 show that 2,518.9 MW came out of suspension and are now active and 40.0 MW began construction in the first nine months of 2018.

24 Wind and solar capacity in Table 12-11 through Table 12-15 have not been adjusted to reflect derating.

**Table 12-12 Change in project status (MW): December 31, 2017 to September 30, 2018**

| | | Status at 9/30/2018 | | | | |
|---|---|---|---|---|---|---|
| Status as 12/31/2017 | Total at 12/31/2017 | Active | In Service | Under Construction | Suspended | Withdrawn |
| (Entered during 2018) | 0.0 | 22,169.1 | 0.0 | 0.0 | 0.0 | 7,372.3 |
| Active | 71,405.5 | 56,568.3 | 221.7 | 844.2 | 3,018.8 | 10,752.6 |
| In Service | 52,043.5 | 0.0 | 52,042.6 | 0.0 | 0.0 | 0.9 |
| Under Construction | 18,813.2 | 20.0 | 7,373.6 | 10,928.7 | 224.0 | 266.9 |
| Suspended | 9,356.1 | 2,518.9 | 100.0 | 40.0 | 5,061.5 | 1,635.7 |
| Withdrawn | 322,847.7 | 0.0 | 0.0 | 0.0 | 0.0 | 322,847.7 |
| Total | 474,465.9 | 81,276.3 | 59,737.9 | 11,812.9 | 8,304.3 | 342,875.9 |

On September 30, 2018, 101,393.4 MW of capacity were in generation request queues in the status of active, suspended or under construction. Table 12-13 shows each status by unit type. Of the 81,276.3 MW in the status of Active on September 30, 2018, 31,804.8 MW (39.1 percent) were combined cycle projects. Of the 11,812.9 MW in the status of under construction, 8,011.6 MW (67.8 percent) were combined cycle projects.

**Table 12-13 Current project status (MW) by unit type: September 30, 2018**

| | Battery | Combined Cycle | CT - Natural Gas | CT - Oil | CT - Other | Fuel Cell | Hydro - Pumped Storage | Hydro - Run of River | Nuclear | RICE - Natural Gas | RICE - Oil | RICE - Other | Solar | Steam - Coal | Steam - Natural Gas | Steam - Oil | Steam - Other | Wind | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Active | 664.9 | 31,804.8 | 3,103.8 | 14.0 | 0.0 | 1.9 | 1,034.0 | 20.5 | 167.5 | 111.8 | 4.0 | 16.4 | 24,820.3 | 99.0 | 94.0 | 0.0 | 40.0 | 19,279.4 | 81,276.3 |
| Suspended | 66.3 | 6,481.1 | 268.8 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 79.6 | 0.0 | 0.0 | 444.5 | 0.0 | 0.0 | 0.0 | 16.0 | 948.0 | 8,304.3 |
| Under Construction | 86.1 | 8,011.6 | 205.0 | 0.0 | 3.2 | 0.0 | 0.0 | 22.7 | 0.0 | 41.2 | 0.0 | 0.0 | 488.7 | 48.0 | 0.0 | 0.0 | 62.5 | 2,843.9 | 11,812.9 |
| Total | 817.2 | 46,297.5 | 3,577.6 | 14.0 | 3.2 | 1.9 | 1,034.0 | 43.2 | 167.5 | 232.6 | 4.0 | 16.4 | 25,753.5 | 147.0 | 94.0 | 0.0 | 118.5 | 23,071.3 | 101,393.4 |

A significant shift in the distribution of unit types within the PJM footprint continues to develop as natural gas fired units enter the queue and coal fired steam units retire. As of September 30, 2018, there were 50,201.7 MW of natural gas fired capacity active, suspended or under construction in PJM queues (including combined cycle units, CTs, RICE units, and natural gas fired steam units). As of September 30, 2018, there were only 147.0 MW of coal fired steam capacity active, suspended or under construction in PJM queues.

There are 7,341.8 MW of coal fired steam capacity and 366.8 MW of natural gas capacity slated for deactivation between September 30, 2018, and December 31, 2021 (See Table 12-9). The replacement of coal fired steam units by natural gas units will significantly affect future congestion, the role of firm and interruptible gas supply, and natural gas supply infrastructure.

Table 12-14 shows the amount of capacity active, in service, under construction, suspended, or withdrawn for each queue since the beginning of the RTEP process and the total amount of capacity that had been included in each queue. All items in queues A-M are either in service or have been withdrawn. As of September 30, 2018, there are 101,393.4 MW of capacity in queues that are not yet in service or withdrawn, of which 8.2 percent are suspended, 11.7 percent are under construction and 80.1 percent have not begun construction.

## Table 12-14 Capacity in PJM queues (MW): September 30, 2018[25]

| Queue | Active | In Service | Under Construction | Suspended | Withdrawn | Total |
|---|---|---|---|---|---|---|
| A Expired 31-Jan-98 | 0.0 | 9,094.0 | 0.0 | 0.0 | 17,252.0 | 26,346.0 |
| B Expired 31-Jan-99 | 0.0 | 4,645.5 | 0.0 | 0.0 | 14,956.7 | 19,602.2 |
| C Expired 31-Jul-99 | 0.0 | 531.0 | 0.0 | 0.0 | 3,558.3 | 4,089.3 |
| D Expired 31-Jan-00 | 0.0 | 850.6 | 0.0 | 0.0 | 7,358.0 | 8,208.6 |
| E Expired 31-Jul-00 | 0.0 | 795.2 | 0.0 | 0.0 | 8,021.8 | 8,817.0 |
| F Expired 31-Jan-01 | 0.0 | 52.0 | 0.0 | 0.0 | 3,092.5 | 3,144.5 |
| G Expired 31-Jul-01 | 0.0 | 1,189.6 | 0.0 | 0.0 | 17,961.8 | 19,151.4 |
| H Expired 31-Jan-02 | 0.0 | 702.5 | 0.0 | 0.0 | 8,421.9 | 9,124.4 |
| I Expired 31-Jul-02 | 0.0 | 103.0 | 0.0 | 0.0 | 3,728.4 | 3,831.4 |
| J Expired 31-Jan-03 | 0.0 | 42.0 | 0.0 | 0.0 | 846.0 | 888.0 |
| K Expired 31-Jul-03 | 0.0 | 99.0 | 0.0 | 0.0 | 485.3 | 584.3 |
| L Expired 31-Jan-04 | 0.0 | 256.5 | 0.0 | 0.0 | 4,033.7 | 4,290.2 |
| M Expired 31-Jul-04 | 0.0 | 504.8 | 0.0 | 0.0 | 3,705.6 | 4,210.4 |
| N Expired 31-Jan-05 | 0.0 | 2,398.8 | 38.0 | 0.0 | 8,090.2 | 10,527.0 |
| O Expired 31-Jul-05 | 0.0 | 1,688.2 | 437.0 | 0.0 | 5,466.8 | 7,592.0 |
| P Expired 31-Jan-06 | 0.0 | 3,037.3 | 253.0 | 0.0 | 5,320.5 | 8,610.8 |
| Q Expired 31-Jul-06 | 0.0 | 3,147.9 | 0.0 | 0.0 | 11,385.7 | 14,533.6 |
| R Expired 31-Jan-07 | 1,040.0 | 2,046.4 | 0.0 | 0.0 | 19,668.9 | 22,755.3 |
| S Expired 31-Jul-07 | 70.0 | 3,669.5 | 0.0 | 0.0 | 12,396.5 | 16,136.0 |
| T Expired 31-Jan-08 | 0.0 | 3,014.0 | 1,182.5 | 0.0 | 23,313.3 | 27,509.8 |
| U1 Expired 30-Apr-08 | 0.0 | 206.9 | 12.0 | 0.0 | 7,937.8 | 8,156.7 |
| U2 Expired 31-Jul-08 | 420.0 | 267.5 | 560.0 | 0.0 | 15,932.2 | 17,179.7 |
| U3 Expired 31-Oct-08 | 100.0 | 334.0 | 20.0 | 0.0 | 2,514.6 | 2,968.6 |
| U4 Expired 31-Jan-09 | 500.0 | 85.2 | 0.0 | 0.0 | 4,445.0 | 5,030.2 |
| V1 Expired 30-Apr-09 | 40.0 | 197.9 | 0.0 | 0.0 | 2,532.8 | 2,770.7 |
| V2 Expired 31-Jul-09 | 150.0 | 989.9 | 16.1 | 0.0 | 3,475.1 | 4,631.1 |
| V3 Expired 31-Oct-09 | 200.0 | 912.0 | 20.0 | 0.0 | 3,822.7 | 4,954.7 |
| V4 Expired 31-Jan-10 | 0.0 | 748.8 | 0.0 | 205.0 | 3,503.0 | 4,456.8 |
| W1 Expired 30-Apr-10 | 13.5 | 345.9 | 300.0 | 0.0 | 5,139.5 | 5,798.9 |
| W2 Expired 31-Jul-10 | 10.0 | 289.2 | 62.5 | 23.0 | 3,018.7 | 3,403.4 |
| W3 Expired 31-Oct-10 | 371.0 | 480.3 | 67.7 | 100.0 | 8,203.1 | 9,222.0 |
| W4 Expired 31-Jan-11 | 7.4 | 1,101.8 | 399.9 | 415.0 | 3,698.2 | 5,622.3 |
| X1 Expired 30-Apr-11 | 0.0 | 1,103.8 | 0.0 | 0.0 | 6,200.6 | 7,304.4 |
| X2 Expired 31-Jul-11 | 0.0 | 3,544.4 | 187.5 | 585.0 | 5,578.4 | 9,895.2 |
| X3 Expired 31-Oct-11 | 0.0 | 89.2 | 20.0 | 894.0 | 6,771.9 | 7,775.1 |
| X4 Expired 31-Jan-12 | 0.0 | 1,929.4 | 1,019.5 | 0.0 | 2,419.4 | 5,368.3 |
| Y1 Expired 30-Apr-12 | 106.0 | 1,797.5 | 452.0 | 0.0 | 5,721.7 | 8,077.2 |
| Y2 Expired 31-Oct-12 | 378.3 | 1,051.8 | 387.1 | 229.0 | 9,247.5 | 11,293.7 |
| Y3 Expired 30-Apr-13 | 0.0 | 626.3 | 1,004.2 | 0.0 | 4,609.2 | 6,239.6 |
| Z1 Expired 31-Oct-13 | 713.0 | 1,247.0 | 2,127.8 | 39.8 | 3,997.2 | 8,124.8 |
| Z2 Expired 30-Apr-14 | 305.6 | 2,272.4 | 585.0 | 52.9 | 2,949.9 | 6,165.8 |
| AA1 Expired 31-Oct-14 | 3,171.4 | 753.8 | 1,618.9 | 683.1 | 5,771.5 | 11,998.7 |
| AA2 Expired 30-Apr-15 | 4,403.5 | 476.9 | 700.7 | 2,371.0 | 8,114.2 | 16,066.3 |
| AB1 Expired 31-Oct-15 | 9,127.4 | 706.5 | 234.4 | 1,235.3 | 9,149.0 | 20,452.6 |
| AB2 Expired 31-Mar-16 | 9,756.7 | 122.5 | 55.0 | 183.6 | 5,099.6 | 15,217.4 |
| AC1 Expired 30-Sep-16 | 12,513.9 | 103.2 | 51.5 | 1,263.7 | 6,143.3 | 20,075.6 |
| AC2 Expired 30-Apr-17 | 5,351.7 | 80.0 | 0.6 | 23.9 | 7,165.5 | 12,621.6 |
| AD1 Expired 30-Sep-17 | 9,365.1 | 6.2 | 0.0 | 0.0 | 2,075.9 | 11,447.2 |
| AD2 Expired 31-Mar-18 | 12,632.6 | 0.0 | 0.0 | 0.0 | 7,848.4 | 20,481.0 |
| AE1 Expired 30-Sep-18 | 10,529.1 | 0.0 | 0.0 | 0.0 | 726.3 | 11,255.4 |
| Total | 81,276.3 | 59,737.9 | 11,812.9 | 8,304.3 | 342,875.9 | 504,007.2 |

25 Projects listed as partially in service are counted as in service for the purposes of this analysis.

Table 12-15 shows the projects with a status of active, suspended or under construction, by unit type, and control zone. As of September 30, 2018, 101,393.4 MW of capacity were in generation request queues for construction through 2029.[26] Table 12-15 also shows the planned retirements for each zone.

26 Since wind resources cannot be dispatched on demand, PJM rules previously required that the unforced capacity of wind resources be derated to 20 percent of nameplate capacity until actual generation data are available. Beginning with Queue U, PJM derates wind resources to 13 percent of nameplate capacity until there is operational data to support a different conclusion. PJM derates solar resources to 38 percent of nameplate capacity. Based on the derating of 23,071.3 MW of wind resources and 25,753.5 MW of solar resources, the 101,393.4 MW currently under construction, suspended or active in the queue would be reduced to 65,354.2 MW.

Table 12-15 Queue totals for projects (active, suspended and under construction) by LDA, control zone and unit type (MW): September 30, 2018[27]

| LDA | Zone | Battery | CC | CT - Natural Gas | CT - Oil | CT - Other | Fuel Cell | Hydro - Pumped Storage | Hydro - Run of River | Nuclear | RICE - Natural Gas | RICE - Oil | RICE - Other | Solar | Steam - Coal | Steam - Natural Gas | Steam - Oil | Steam - Other | Wind | Total Queue Capacity | Planned Retirments |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| EMAAC | AECO | 50.0 | 1,748.6 | 388.0 | 0.0 | 0.0 | 0.4 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 48.3 | 0.0 | 0.0 | 0.0 | 0.0 | 619.0 | 2,854.3 | 155.0 |
| | DPL | 1.0 | 451.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 15.6 | 1,402.0 | 0.0 | 0.0 | 0.0 | 0.0 | 247.8 | 2,117.4 | 0.0 |
| | JCPL | 128.3 | 605.0 | 200.0 | 0.0 | 0.0 | 0.2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 154.6 | 0.0 | 0.0 | 0.0 | 0.0 | 2,640.0 | 3,728.0 | 6.4 |
| | PECO | 0.0 | 982.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 94.0 | 0.0 | 4.0 | 0.0 | 18.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 1,098.0 | 54.1 |
| | PSEG | 2.0 | 3,710.5 | 0.0 | 0.0 | 0.0 | 1.3 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 85.4 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 3,799.2 | 0.0 |
| | RECO | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 40.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 40.0 | 0.0 |
| | EMAAC Total | 181.2 | 7,497.1 | 588.0 | 0.0 | 0.0 | 1.9 | 0.0 | 0.0 | 94.0 | 0.0 | 4.0 | 15.6 | 1,748.3 | 0.0 | 0.0 | 0.0 | 0.0 | 3,506.8 | 13,636.9 | 215.5 |
| SWMAAC | BGE | 0.1 | 0.0 | 144.6 | 14.0 | 0.0 | 0.0 | 0.0 | 0.0 | 45.5 | 1.3 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 205.5 | 135.0 |
| | Pepco | 0.0 | 1,197.1 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 76.3 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 1,273.4 | 0.0 |
| | SWMAAC Total | 0.1 | 1,197.1 | 144.6 | 14.0 | 0.0 | 0.0 | 0.0 | 0.0 | 45.5 | 1.3 | 0.0 | 0.0 | 76.3 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 1,478.9 | 135.0 |
| WMAAC | Met-Ed | 0.0 | 598.9 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 230.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 828.9 | 805.0 |
| | PENELEC | 0.0 | 1,348.0 | 531.8 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 119.6 | 0.0 | 0.0 | 246.9 | 0.0 | 0.0 | 0.0 | 0.0 | 290.3 | 2,536.6 | 110.0 |
| | PPL | 30.0 | 3,205.8 | 0.0 | 0.0 | 0.0 | 0.0 | 1,000.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 30.0 | 0.0 | 0.0 | 0.0 | 16.0 | 531.1 | 4,812.9 | 52.0 |
| | WMAAC Total | 30.0 | 5,152.7 | 531.8 | 0.0 | 0.0 | 0.0 | 1,000.0 | 0.0 | 0.0 | 119.6 | 0.0 | 0.0 | 506.9 | 0.0 | 0.0 | 0.0 | 16.0 | 821.4 | 8,178.4 | 967.0 |
| Non-MAAC | AEP | 104.0 | 8,016.0 | 413.0 | 0.0 | 3.2 | 0.0 | 34.0 | 0.0 | 28.0 | 12.0 | 0.0 | 0.8 | 6,894.0 | 101.0 | 30.0 | 0.0 | 40.0 | 6,519.3 | 22,195.2 | 0.0 |
| | APS | 145.5 | 6,325.7 | 120.0 | 0.0 | 0.0 | 0.0 | 0.0 | 15.0 | 0.0 | 99.7 | 0.0 | 0.0 | 830.8 | 0.0 | 0.0 | 0.0 | 0.0 | 1,184.4 | 8,721.1 | 1,278.0 |
| | ATSI | 8.8 | 4,386.0 | 70.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 940.9 | 0.0 | 0.0 | 0.0 | 0.0 | 816.1 | 6,221.7 | 6,791.0 |
| | ComEd | 232.9 | 7,006.8 | 1,238.0 | 0.0 | 0.0 | 0.0 | 0.0 | 22.7 | 0.0 | 0.0 | 0.0 | 0.0 | 1,679.5 | 0.0 | 64.0 | 0.0 | 0.0 | 6,899.7 | 17,143.6 | 0.0 |
| | DAY | 19.9 | 1,150.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 1,136.5 | 12.0 | 0.0 | 0.0 | 0.0 | 100.0 | 2,418.4 | 0.0 |
| | DEOK | 19.8 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 380.0 | 20.0 | 0.0 | 0.0 | 0.0 | 0.0 | 419.8 | 0.0 |
| | DLCO | 20.0 | 0.0 | 205.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 20.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 245.0 | 1,777.0 |
| | Dominion | 55.0 | 5,566.1 | 194.2 | 0.0 | 0.0 | 0.0 | 0.0 | 5.5 | 0.0 | 0.0 | 0.0 | 0.0 | 11,215.5 | 14.0 | 0.0 | 0.0 | 62.5 | 3,223.7 | 20,336.5 | 1,304.5 |
| | EKPC | 0.0 | 0.0 | 73.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 325.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 398.0 | 0.0 |
| | RMU | 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 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | Non-MAAC Total | 605.9 | 32,450.6 | 2,313.2 | 0.0 | 3.2 | 0.0 | 34.0 | 43.2 | 28.0 | 111.7 | 0.0 | 0.8 | 23,422.1 | 147.0 | 94.0 | 0.0 | 102.5 | 18,743.1 | 78,099.3 | 11,150.5 |
| | Total | 817.2 | 46,297.5 | 3,577.6 | 14.0 | 3.2 | 1.9 | 1,034.0 | 43.2 | 167.5 | 232.6 | 4.0 | 16.4 | 25,753.5 | 147.0 | 94.0 | 0.0 | 118.5 | 23,071.3 | 101,393.4 | 12,468.0 |

## Withdrawn Projects

The queue contains a substantial number of projects that are not likely to be built. The queue process results in a substantial number of projects that are withdrawn. Manual 14B requires PJM to apply a commercial probability factor at the feasibility study stage to improve the accuracy of capacity and cost estimates. The commercial probability factor is based on the historical incidence of projects dropping out of the queue at the impact study stage.[28] The impact and facilities studies are performed using the full amount of planned generation in the queues. The actual withdrawal rates are shown in Table 12-16 and Table 12-17.

Table 12-16 shows the milestone status when projects were withdrawn, for all withdrawn projects. Of the 2,323 projects withdrawn, 1,188 (51.1 percent) were withdrawn before the system impact study was completed. Once an Interconnection Service Agreement (ISA) or a Wholesale Market Participation Agreement

27 This data includes only projects with a status of active, under construction, or suspended.

28 See PJM. "Manual 14B: PJM Region Transmission Planning Process," Rev. 42 (August 23, 2018), p.82.

(WMPA) is executed, the financial obligation for any necessary transmission upgrades cannot be retracted.[29] [30] Of the 2,323 projects withdrawn, 442 (19.0 percent) were withdrawn after the completion of a Construction Service Agreement.

**Table 12-16 Last milestone at time of withdrawal: January 1997 through September 2018**

| Milestone Completed | Projects Withdrawn | Percent | Average Days | Maximum Days |
|---|---|---|---|---|
| Never Started | 376 | 16.2% | 99 | 875 |
| Feasibility Study | 759 | 32.7% | 274 | 1,633 |
| System Impact Study | 469 | 20.2% | 751 | 3,248 |
| Facilities Study | 277 | 11.9% | 1,073 | 3,454 |
| Construction Service Agreement (CSA) or beyond | 442 | 19.0% | 1,261 | 4,249 |
| Total | 2,323 | 100.0% | | |

## Average Time in Queue

Table 12-17 shows the time spent at various stages in the queue process and the completion time for the studies performed. For completed projects, there is an average time of 1,017 days, or 2.8 years, between entering a queue and going into service. For withdrawn projects, there is an average time of 617 days, or 1.7 years, between entering a queue and withdrawing.

**Table 12-17 Project queue times by status (days): September 30, 2018[31]**

| Status | Average (Days) | Standard Deviation | Minimum | Maximum |
|---|---|---|---|---|
| Active | 501 | 609 | 0 | 4,211 |
| In-Service | 1,017 | 728 | 0 | 4,024 |
| Suspended | 1,500 | 905 | 366 | 4,177 |
| Under Construction | 1,820 | 1,073 | 486 | 4,933 |
| Withdrawn | 617 | 689 | 0 | 4,249 |

Table 12-18 presents information on the time in the stages of the queue for those projects not yet in service or already withdrawn. Of the 841 projects in the queue as of September 30, 2018, 236 (28.1 percent) had a completed feasibility study and 279 (33.2 percent) were under construction.

**Table 12-18 Project queue times by milestone (days): September 30, 2018**

| Milestone Reached | Number of Projects | Percent of Total Projects | Average Days | Maximum Days |
|---|---|---|---|---|
| Under Review | 117 | 13.9% | 140 | 368 |
| Feasibility Study | 236 | 28.1% | 424 | 1,347 |
| System Impact Study | 174 | 20.7% | 811 | 3,570 |
| Facilities Study | 35 | 4.2% | 1,365 | 3,654 |
| Construction Service Agreement (CSA) or beyond | 279 | 33.2% | 1,566 | 5,116 |
| Total | 841 | 100.0% | | |

## Completion Rates

The probability of a project going into service increases as each step of the planning process is completed. Table 12-19 shows the historic completion rates (MW energy) by unit type for projects that have completed the system impact study, facilities study and construction service agreement stages. For example, of all wind projects to ever enter the queue and complete the system impact study stage, 15.9 percent of the queued MW have gone into service. The completion rate for wind projects increases to 31.1 percent when wind projects complete the facility study agreement, and further increases to 48.9 percent when wind projects complete the construction service agreement.

29 "Generators planning to connect to the local distribution systems at locations that are not under FERC jurisdiction and wish to participate in PJM's market need to execute a PJM Wholesale Market Participation Agreement (WMPA)..." instead of an ISA. See PJM. "Manual 14C: Generation and Transmission Interconnection Facility Construction," Rev. 12 (June 22, 2017).
30 See PJM. "Manual 14C: Generation and Transmission Interconnection Facility Construction," Rev. 13 (August 23, 2018).
31 The queue data shows that some projects were withdrawn and a withdrawal date was not identified. These projects were removed for the purposes of this analysis.

**Table 12-19 Historic completion rates (MW energy) by unit type for projects with a completed SIS, FSA and CSA: January 1997 through September 2018**

| Unit Type | Completion Rate (SIS) | Completion Rate (FSA) | Completion Rate (CSA) |
|---|---|---|---|
| Battery | 23.3% | 44.3% | 60.1% |
| CC | 30.7% | 50.8% | 85.6% |
| CT - Natural Gas | 80.3% | 83.3% | 87.3% |
| CT - Oil | 35.6% | 60.3% | 90.9% |
| CT - Other | 12.5% | 19.0% | 30.2% |
| Fuel Cell | 41.6% | 43.5% | 43.5% |
| Hydro - Pumped Storage | 100.0% | 100.0% | 100.0% |
| Hydro - Run of River | 40.8% | 56.9% | 62.3% |
| Nuclear | 34.9% | 41.8% | 51.2% |
| RICE - Natural Gas | 38.2% | 58.6% | 70.7% |
| RICE - Oil | 30.6% | 55.9% | 55.9% |
| RICE - Other | 90.6% | 90.6% | 91.3% |
| Solar | 15.1% | 27.6% | 35.4% |
| Steam - Coal | 13.3% | 24.8% | 36.8% |
| Steam - Natural Gas | 96.5% | 96.5% | 96.5% |
| Steam - Oil | 0.0% | 0.0% | 0.0% |
| Steam - Other | 27.9% | 37.2% | 45.2% |
| Wind | 15.9% | 31.1% | 48.9% |

## Queue Analysis by Fuel

The time it takes to complete a study depends on the backlog and the number of projects in the queue, but not on the size of the project. Table 12-20 shows the number of projects that entered the queue by year. The number of queue entries has increased during the past several years, primarily by renewable projects (solar, hydro, storage, biomass, wind). Of the 1,317 projects entered in 2015, 2016, 2017 and the first nine months of 2018, 1,037 projects, 78.7 percent, were renewable. Of the 254 projects entered in the first nine months of 2018, 221 projects, 87.0 percent, were renewable.

**Table 12-20 Number of projects entered in the queue: September 30, 2018**

| | Fuel Group | | | |
|---|---|---|---|---|
| Year Entered | Nuclear | Renewable | Traditional | Total |
| 1997 | 2 | 0 | 11 | 13 |
| 1998 | 0 | 0 | 18 | 18 |
| 1999 | 1 | 5 | 84 | 90 |
| 2000 | 2 | 3 | 78 | 83 |
| 2001 | 4 | 6 | 81 | 91 |
| 2002 | 3 | 15 | 33 | 51 |
| 2003 | 1 | 34 | 18 | 53 |
| 2004 | 4 | 17 | 33 | 54 |
| 2005 | 3 | 75 | 55 | 133 |
| 2006 | 9 | 67 | 81 | 157 |
| 2007 | 9 | 65 | 145 | 219 |
| 2008 | 3 | 109 | 104 | 216 |
| 2009 | 10 | 109 | 54 | 173 |
| 2010 | 5 | 375 | 61 | 441 |
| 2011 | 6 | 268 | 81 | 355 |
| 2012 | 2 | 70 | 87 | 159 |
| 2013 | 1 | 75 | 78 | 154 |
| 2014 | 0 | 121 | 71 | 192 |
| 2015 | 0 | 196 | 113 | 309 |
| 2016 | 2 | 320 | 77 | 399 |
| 2017 | 2 | 300 | 53 | 355 |
| 2018 | 1 | 221 | 32 | 254 |
| Total | 70 | 2,451 | 1,448 | 3,969 |

Renewable projects comprise the majority of projects entered in the queue, as well as what is currently active in the queue. Renewable projects make up 50.0 percent of the nameplate MW currently active, suspended or under construction in the queue (Table 12-21).

**Table 12-21 Queue details by fuel group: September 30, 2018**

| Fuel Group | Number of Projects | Percent of Projects | MW | Percent MW |
|---|---|---|---|---|
| Nuclear | 9 | 1.1% | 167.5 | 0.2% |
| Renewable | 639 | 76.0% | 50,721.1 | 50.0% |
| Traditional | 193 | 22.9% | 50,504.8 | 49.8% |
| Total | 841 | 100.0% | 101,393.4 | 100.0% |

## Queue Analysis by Unit Type and Project Classification

Table 12-22 shows the current status of all generation queue projects by unit type and project classification from January 1, 1997, through September 30, 2018. As of September 30, 2018, 3,969 projects, representing 504,007.2 MW, have entered the queue process since its inception. Of those, 805 projects, representing 59,737.9 MW, went into service. Of the projects that entered the queue process, 2,323 projects, representing 342,875.9 MW (68.0 percent of the MW) withdrew prior to completion. Such projects may create barriers to entry for projects that would otherwise be completed by taking up queue positions, increasing interconnection costs and creating uncertainty.

A total of 3,217 projects have been classified as new generation and 752 projects have been classified as upgrades. Wind, solar and natural gas projects have accounted for 3,130 projects, or 78.9 percent, of all 3,969 generation queue projects.

**Table 12-22 Status of all generation queue projects: January 1997 through September 2018**

| | | Number of Projects | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Project Status | Project Classification | Battery | CC | CT - Natural Gas | CT - Oil | CT - Other | Fuel Cell | Hydro - Pumped Storage | Hydro - Run of River | Nuclear | RICE - Natural Gas | RICE - Oil | RICE - Other | Solar | Steam - Coal | Steam - Natural Gas | Steam - Oil | Steam - Other | Wind | Total |
| In Service | New Generation | 18 | 53 | 48 | 10 | 24 | 3 | 0 | 11 | 2 | 8 | 0 | 55 | 127 | 8 | 5 | 0 | 3 | 76 | 451 |
| | Upgrade | 4 | 73 | 89 | 15 | 5 | 0 | 2 | 16 | 41 | 8 | 1 | 14 | 16 | 51 | 7 | 0 | 7 | 5 | 354 |
| Under Construction | New Generation | 25 | 9 | 1 | 0 | 1 | 0 | 0 | 2 | 0 | 3 | 0 | 0 | 21 | 0 | 0 | 0 | 0 | 17 | 79 |
| | Upgrade | 1 | 12 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 3 | 2 | 0 | 0 | 1 | 2 | 22 |
| Suspended | New Generation | 7 | 8 | 3 | 0 | 0 | 0 | 0 | 0 | 0 | 4 | 0 | 0 | 32 | 0 | 0 | 0 | 1 | 8 | 63 |
| | Upgrade | 2 | 6 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 1 | 11 |
| Withdrawn | New Generation | 95 | 401 | 15 | 9 | 81 | 18 | 0 | 39 | 9 | 18 | 12 | 14 | 919 | 55 | 1 | 0 | 34 | 398 | 2,118 |
| | Upgrade | 14 | 80 | 5 | 13 | 13 | 2 | 0 | 4 | 9 | 0 | 2 | 2 | 25 | 14 | 0 | 0 | 2 | 20 | 205 |
| Active | New Generation | 19 | 37 | 9 | 1 | 0 | 9 | 3 | 1 | 1 | 6 | 0 | 2 | 350 | 0 | 0 | 0 | 0 | 68 | 506 |
| | Upgrade | 10 | 43 | 28 | 0 | 0 | 0 | 1 | 1 | 8 | 1 | 1 | 3 | 35 | 5 | 3 | 0 | 1 | 20 | 160 |
| Total Projects | New Generation | 164 | 508 | 76 | 20 | 106 | 30 | 3 | 53 | 12 | 39 | 12 | 71 | 1,449 | 63 | 6 | 0 | 38 | 567 | 3,217 |
| | Upgrade | 31 | 214 | 124 | 28 | 18 | 2 | 3 | 21 | 58 | 9 | 4 | 19 | 80 | 72 | 10 | 0 | 11 | 48 | 752 |

Table 12-23 shows the totals in Table 12-22 by share of classification as new generation or upgrade. Within a unit type the shares of upgrades add to 100 percent and the shares of new generation add to 100 percent. For example, 76.2 percent of all hydro – run of river projects classified as upgrades are currently in service in PJM, 19.0 percent of hydro – run of river upgrades were withdrawn and 4.8 percent of hydro – run of river upgrades are active in the queue.

### Table 12-23 Status of all generation queue projects as a percent of total projects by classification: January 1997 through September 2018

| | | Percent of Projects | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Project Status | Project Classification | Battery | CC | CT - Natural Gas | CT - Oil | CT - Other | Fuel Cell | Hydro - Pumped Storage | Hydro - Run of River | Nuclear | RICE - Natural Gas | RICE - Oil | RICE - Other | Solar | Steam - Coal | Steam - Natural Gas | Steam - Oil | Steam - Other | Wind | Total |
| In Service | New Generation | 11.0% | 10.4% | 63.2% | 50.0% | 22.6% | 10.0% | 0.0% | 20.8% | 16.7% | 20.5% | 0.0% | 77.5% | 8.8% | 12.7% | 83.3% | 0.0% | 7.9% | 13.4% | 14.0% |
| | Upgrade | 12.9% | 34.1% | 71.8% | 53.6% | 27.8% | 0.0% | 66.7% | 76.2% | 70.7% | 88.9% | 25.0% | 73.7% | 20.0% | 70.8% | 70.0% | 0.0% | 63.6% | 10.4% | 47.1% |
| Under Construction | New Generation | 15.2% | 1.8% | 1.3% | 0.0% | 0.9% | 0.0% | 0.0% | 3.8% | 0.0% | 7.7% | 0.0% | 0.0% | 1.4% | 0.0% | 0.0% | 0.0% | 0.0% | 3.0% | 2.5% |
| | Upgrade | 3.2% | 5.6% | 0.8% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 3.8% | 2.8% | 0.0% | 0.0% | 9.1% | 4.2% | 2.9% |
| Suspended | New Generation | 4.3% | 1.6% | 3.9% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 10.3% | 0.0% | 0.0% | 2.2% | 0.0% | 0.0% | 0.0% | 2.6% | 1.4% | 2.0% |
| | Upgrade | 6.5% | 2.8% | 0.8% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 1.3% | 0.0% | 0.0% | 0.0% | 0.0% | 2.1% | 1.5% |
| Withdrawn | New Generation | 57.9% | 78.9% | 19.7% | 45.0% | 76.4% | 60.0% | 0.0% | 73.6% | 75.0% | 46.2% | 100.0% | 19.7% | 63.4% | 87.3% | 16.7% | 0.0% | 89.5% | 70.2% | 65.8% |
| | Upgrade | 45.2% | 37.4% | 4.0% | 46.4% | 72.2% | 100.0% | 0.0% | 19.0% | 15.5% | 0.0% | 50.0% | 10.5% | 31.3% | 19.4% | 0.0% | 0.0% | 18.2% | 41.7% | 27.3% |
| Active | New Generation | 11.6% | 7.3% | 11.8% | 5.0% | 0.0% | 30.0% | 100.0% | 1.9% | 8.3% | 15.4% | 0.0% | 2.8% | 24.2% | 0.0% | 0.0% | 0.0% | 0.0% | 12.0% | 15.7% |
| | Upgrade | 32.3% | 20.1% | 22.6% | 0.0% | 0.0% | 0.0% | 33.3% | 4.8% | 13.8% | 11.1% | 25.0% | 15.8% | 43.8% | 6.9% | 30.0% | 0.0% | 9.1% | 41.7% | 21.3% |

Table 12-24 shows the nameplate generating capacity of projects in the PJM generation queue by technology type and project classification. For example, the 398 new generation wind projects that have been withdrawn from the queue as of September 30, 2018, (as shown in Table 12-22) constitute 65,113.0 MW of nameplate capacity. The 481 new generation and upgrade combined cycle projects that have been withdrawn in the same time period constitute 201,325.9 MW of nameplate capacity.

### Table 12-24 Status of all generation capacity (MW) in the PJM generation queue: January 1997 through September 2018

| | | Project MW | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Project Status | Project Classification | Battery | CC | CT - Natural Gas | CT - Oil | CT - Other | Fuel Cell | Hydro - Pumped Storage | Hydro - Run of River | Nuclear | RICE - Natural Gas | RICE - Oil | RICE - Other | Solar | Steam - Coal | Steam - Natural Gas | Steam - Oil | Steam - Other | Wind | Total |
| In Service | New Generation | 156.4 | 26,396.0 | 6,600.5 | 676.5 | 148.2 | 1.9 | 0.0 | 471.5 | 1,639.0 | 118.2 | 0.0 | 440.1 | 1,299.3 | 1,343.0 | 723.0 | 0.0 | 60.0 | 7,191.1 | 47,264.7 |
| | Upgrade | 42.4 | 4,990.8 | 2,558.5 | 127.8 | 12.3 | 0.0 | 356.0 | 373.6 | 2,282.8 | 15.7 | 23.3 | 49.9 | 19.4 | 883.5 | 131.5 | 0.0 | 605.3 | 0.5 | 12,473.3 |
| Under Construction | New Generation | 86.1 | 6,910.5 | 205.0 | 0.0 | 3.2 | 0.0 | 0.0 | 22.7 | 0.0 | 41.2 | 0.0 | 0.0 | 474.8 | 0.0 | 0.0 | 0.0 | 0.0 | 2,811.9 | 10,555.4 |
| | Upgrade | 0.0 | 1,101.1 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 13.9 | 48.0 | 0.0 | 0.0 | 62.5 | 32.0 | 1,257.5 |
| Suspended | New Generation | 43.3 | 5,721.0 | 68.8 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 79.6 | 0.0 | 0.0 | 424.7 | 0.0 | 0.0 | 0.0 | 16.0 | 931.7 | 7,285.1 |
| | Upgrade | 23.0 | 760.1 | 200.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 19.8 | 0.0 | 0.0 | 0.0 | 0.0 | 16.3 | 1,019.2 |
| Withdrawn | New Generation | 1,391.3 | 191,371.8 | 1,556.0 | 1,721.0 | 1,244.2 | 3.8 | 0.0 | 1,986.9 | 8,161.0 | 288.4 | 63.9 | 77.0 | 21,298.8 | 33,511.6 | 27.0 | 0.0 | 1,035.8 | 65,113.0 | 328,851.4 |
| | Upgrade | 301.1 | 9,954.2 | 273.5 | 589.0 | 72.5 | 0.9 | 0.0 | 57.1 | 916.0 | 0.0 | 13.0 | 6.0 | 502.1 | 865.0 | 0.0 | 0.0 | 37.1 | 437.0 | 14,024.5 |
| Active | New Generation | 423.9 | 28,459.6 | 1,633.8 | 14.0 | 0.0 | 1.9 | 1,000.0 | 15.0 | 28.0 | 110.2 | 0.0 | 11.6 | 22,972.6 | 0.0 | 0.0 | 0.0 | 0.0 | 17,663.9 | 72,334.4 |
| | Upgrade | 241.0 | 3,345.2 | 1,470.0 | 0.0 | 0.0 | 0.0 | 34.0 | 5.5 | 139.5 | 1.6 | 4.0 | 4.8 | 1,847.8 | 99.0 | 94.0 | 0.0 | 40.0 | 1,615.5 | 8,941.8 |
| Total Projects | New Generation | 2,100.9 | 258,858.9 | 10,064.1 | 2,411.5 | 1,395.6 | 7.6 | 1,000.0 | 2,496.1 | 9,828.0 | 637.6 | 63.9 | 528.7 | 46,470.1 | 34,854.6 | 750.0 | 0.0 | 1,111.8 | 93,711.6 | 466,291.0 |
| | Upgrade | 607.5 | 20,151.4 | 4,502.0 | 716.8 | 84.8 | 0.9 | 390.0 | 436.2 | 3,338.3 | 17.3 | 40.3 | 60.7 | 2,403.0 | 1,895.5 | 225.5 | 0.0 | 744.9 | 2,101.3 | 37,716.3 |

Table 12-25 shows the MW totals in Table 12-24 by share by classification as new generation or upgrade. Within a unit type the shares of upgrades add to 100 percent and the shares of new generation add to 100 percent. For example, 69.5 percent of wind project MW classified as new generation have been withdrawn from the queue between January 1, 1997, and September 30, 2018.

**Table 12-25 Status of all generation queue projects as percent of total MW in project classification: January 1997 through September 2018**

| | | Percent of Total Projects by Classification | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Project Status | Project Classification | Battery | CC | CT - Natural Gas | CT - Oil | CT - Other | Fuel Cell | Hydro - Pumped Storage | Hydro - Run of River | Nuclear | RICE - Natural Gas | RICE - Oil | RICE - Other | Solar | Steam - Coal | Steam - Natural Gas | Steam - Oil | Steam - Other | Wind | Total |
| In Service | New Generation | 7.4% | 10.2% | 65.6% | 28.1% | 10.6% | 25.5% | 0.0% | 18.9% | 16.7% | 18.5% | 0.0% | 83.2% | 2.8% | 3.9% | 96.4% | 0.0% | 5.4% | 7.7% | 10.1% |
| | Upgrade | 7.0% | 24.8% | 56.8% | 17.8% | 14.5% | 0.0% | 91.3% | 85.6% | 68.4% | 90.8% | 57.8% | 82.2% | 0.8% | 46.6% | 58.3% | 0.0% | 81.3% | 0.0% | 33.1% |
| Under Construction | New Generation | 4.1% | 2.7% | 2.0% | 0.0% | 0.2% | 0.0% | 0.0% | 0.9% | 0.0% | 6.5% | 0.0% | 0.0% | 1.0% | 0.0% | 0.0% | 0.0% | 0.0% | 3.0% | 2.3% |
| | Upgrade | 0.0% | 5.5% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.6% | 2.5% | 0.0% | 0.0% | 8.4% | 1.5% | 3.3% |
| Suspended | New Generation | 2.1% | 2.2% | 0.7% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 12.5% | 0.0% | 0.0% | 0.9% | 0.0% | 0.0% | 0.0% | 1.4% | 1.0% | 1.6% |
| | Upgrade | 3.8% | 3.8% | 4.4% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.8% | 0.0% | 0.0% | 0.0% | 0.0% | 0.8% | 2.7% |
| Withdrawn | New Generation | 66.2% | 73.9% | 15.5% | 71.4% | 89.2% | 49.7% | 0.0% | 79.6% | 83.0% | 45.2% | 100.0% | 14.6% | 45.8% | 96.1% | 3.6% | 0.0% | 93.2% | 69.5% | 70.5% |
| | Upgrade | 49.6% | 49.4% | 6.1% | 82.2% | 85.5% | 100.0% | 0.0% | 13.1% | 27.4% | 0.0% | 32.3% | 9.9% | 20.9% | 45.6% | 0.0% | 0.0% | 5.0% | 20.8% | 37.2% |
| Active | New Generation | 20.2% | 11.0% | 16.2% | 0.6% | 0.0% | 24.7% | 100.0% | 0.6% | 0.3% | 17.3% | 0.0% | 2.2% | 49.4% | 0.0% | 0.0% | 0.0% | 0.0% | 18.8% | 15.5% |
| | Upgrade | 39.7% | 16.6% | 32.7% | 0.0% | 0.0% | 0.0% | 8.7% | 1.3% | 4.2% | 9.2% | 9.9% | 7.9% | 76.9% | 5.2% | 41.7% | 0.0% | 5.4% | 76.9% | 23.7% |

Table 12-26 shows the project MW that entered the PJM generation queue by unit type and year of entry. Since 2016, 93.9 percent of all new projects entering the generation queue have been either combined cycle (30.9 percent), wind (21.5 percent) or solar projects (41.4 percent).

**Table 12-26 Queue project MW by unit type and queue entry year: January 1997 through September 2018**

| Year | Battery | CC | CT – Natural Gas | CT – Oil | CT – Other | Fuel Cell | Hydro – Pumped Storage | Hydro – Run of River | Nuclear | RICE – Natural Gas | RICE – Oil | RICE – Other | Solar | Steam – Coal | Steam – Natural Gas | Steam – Oil | Steam – Other | Wind | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1997 | 0.0 | 4,148.0 | 321.0 | 315.0 | 0.0 | 0.0 | 0.0 | 0.0 | 50.0 | 0.0 | 0.0 | 0.0 | 0.0 | 6.0 | 0.0 | 0.0 | 0.0 | 0.0 | 4,840.0 |
| 1998 | 0.0 | 7,006.0 | 1,775.0 | 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 | 0.0 | 8,781.0 |
| 1999 | 0.0 | 29,412.7 | 2,412.1 | 0.0 | 10.0 | 0.0 | 0.0 | 196.0 | 45.0 | 0.0 | 0.0 | 0.0 | 0.0 | 47.0 | 0.0 | 0.0 | 525.0 | 115.4 | 32,763.2 |
| 2000 | 0.0 | 21,144.8 | 493.6 | 31.5 | 8.8 | 0.0 | 0.0 | 0.0 | 95.0 | 0.0 | 0.0 | 1.2 | 0.0 | 37.0 | 2.5 | 0.0 | 0.0 | 95.6 | 21,909.9 |
| 2001 | 0.0 | 25,411.7 | 264.0 | 0.0 | 0.0 | 0.0 | 0.0 | 107.0 | 90.0 | 0.0 | 0.0 | 15.6 | 0.0 | 1,244.6 | 10.0 | 0.0 | 0.0 | 252.9 | 27,395.8 |
| 2002 | 0.0 | 4,154.0 | 11.7 | 0.0 | 70.5 | 0.0 | 0.0 | 293.0 | 236.0 | 8.0 | 23.3 | 4.5 | 0.0 | 1,895.0 | 0.0 | 0.0 | 0.0 | 790.9 | 7,486.9 |
| 2003 | 0.0 | 2,361.4 | 10.0 | 8.0 | 0.8 | 0.0 | 0.0 | 2.0 | 0.0 | 29.0 | 0.0 | 27.5 | 0.0 | 522.0 | 0.0 | 0.0 | 165.0 | 1,002.9 | 4,128.6 |
| 2004 | 0.0 | 3,610.0 | 43.3 | 20.0 | 49.1 | 0.0 | 0.0 | 0.0 | 1,911.0 | 0.0 | 35.5 | 17.5 | 0.0 | 1,187.0 | 0.0 | 0.0 | 0.0 | 1,613.7 | 8,487.1 |
| 2005 | 0.0 | 5,824.6 | 1,196.0 | 281.0 | 51.4 | 0.0 | 340.0 | 174.2 | 242.0 | 21.5 | 0.0 | 65.1 | 0.0 | 6,360.0 | 0.0 | 0.0 | 24.0 | 6,020.0 | 20,599.9 |
| 2006 | 0.0 | 4,188.1 | 454.3 | 607.5 | 73.1 | 0.0 | 0.0 | 159.0 | 6,894.0 | 0.0 | 0.0 | 93.0 | 0.0 | 9,586.0 | 0.0 | 0.0 | 258.5 | 7,650.7 | 29,964.2 |
| 2007 | 0.0 | 14,130.6 | 941.2 | 215.9 | 149.5 | 0.0 | 16.0 | 255.4 | 368.0 | 0.0 | 0.0 | 56.5 | 3.3 | 9,078.0 | 190.0 | 0.0 | 50.5 | 18,525.6 | 43,980.4 |
| 2008 | 121.0 | 26,001.0 | 129.7 | 1,113.0 | 488.8 | 0.0 | 0.0 | 1,254.5 | 105.0 | 6.0 | 0.0 | 32.0 | 66.3 | 1,198.0 | 0.0 | 0.0 | 192.3 | 11,199.7 | 41,907.3 |
| 2009 | 34.0 | 5,548.4 | 14.0 | 66.0 | 214.2 | 0.0 | 0.0 | 133.9 | 1,933.8 | 4.5 | 16.0 | 15.2 | 636.5 | 1,273.0 | 5.5 | 0.0 | 148.0 | 6,672.6 | 16,715.6 |
| 2010 | 72.4 | 9,185.4 | 176.0 | 7.9 | 117.3 | 0.0 | 0.0 | 132.6 | 426.0 | 0.0 | 2.4 | 57.8 | 3,690.0 | 64.0 | 0.0 | 0.0 | 173.5 | 9,940.4 | 24,045.7 |
| 2011 | 24.1 | 20,354.5 | 29.5 | 0.0 | 174.6 | 0.0 | 0.0 | 30.0 | 182.0 | 0.0 | 14.0 | 75.3 | 2,022.9 | 357.0 | 0.0 | 0.0 | 49.0 | 5,576.4 | 28,889.3 |
| 2012 | 142.6 | 18,014.8 | 282.1 | 42.5 | 48.4 | 0.0 | 0.0 | 11.8 | 369.0 | 37.2 | 0.0 | 4.0 | 286.6 | 1,837.0 | 0.0 | 0.0 | 143.1 | 1,529.8 | 22,748.8 |
| 2013 | 217.4 | 11,168.1 | 526.8 | 5.0 | 11.2 | 0.0 | 0.0 | 89.4 | 102.0 | 59.7 | 0.0 | 1.6 | 231.7 | 158.0 | 40.0 | 0.0 | 44.7 | 1,407.9 | 14,063.4 |
| 2014 | 246.9 | 11,769.5 | 1,532.5 | 401.0 | 7.7 | 0.0 | 0.0 | 60.5 | 0.0 | 48.0 | 0.0 | 17.7 | 1,445.7 | 1,730.5 | 27.0 | 0.0 | 43.1 | 1,763.7 | 19,093.8 |
| 2015 | 546.9 | 27,540.8 | 1,324.5 | 0.0 | 0.9 | 2.3 | 34.0 | 0.0 | 0.0 | 320.4 | 13.0 | 31.4 | 2,931.6 | 47.0 | 606.5 | 0.0 | 0.0 | 2,160.6 | 35,559.7 |
| 2016 | 111.1 | 18,804.5 | 1,392.0 | 0.0 | 0.0 | 3.4 | 0.0 | 12.5 | 50.3 | 23.5 | 0.0 | 38.9 | 11,771.5 | 80.0 | 77.0 | 0.0 | 0.0 | 3,467.5 | 35,832.2 |
| 2017 | 24.6 | 5,448.1 | 702.0 | 0.0 | 4.1 | 2.9 | 0.0 | 20.5 | 39.1 | 97.1 | 0.0 | 33.8 | 13,899.0 | 14.0 | 17.0 | 0.0 | 0.0 | 5,602.0 | 25,904.3 |
| 2018 | 1,167.4 | 3,783.4 | 534.8 | 14.0 | 0.0 | 0.0 | 1,000.0 | 0.0 | 28.1 | 0.0 | 0.0 | 0.8 | 11,887.9 | 29.0 | 0.0 | 0.0 | 40.0 | 10,424.6 | 28,910.0 |
| Total | 2,708.4 | 279,010.3 | 14,566.1 | 3,128.3 | 1,480.3 | 8.5 | 1,390.0 | 2,932.3 | 13,166.3 | 654.9 | 104.2 | 589.4 | 48,873.1 | 36,750.1 | 975.5 | 0.0 | 1,856.7 | 95,812.9 | 504,007.2 |

## Combined Cycle Project Analysis

Table 12-27 shows the status of all combined cycle projects by number of projects that entered PJM generation queues from January 1, 1997, through September 30, 2018, by zone. Of the 115 combined cycle projects classified either as new generation or upgrade currently active, suspended or under construction in the PJM generation queue, 47 projects (40.9 percent) are located within AEP, ComEd and APS.

### Table 12-27 Status of all combined cycle queue projects by zone (number of projects): January 1997 through September 2018

| | | Number of Projects | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Project Status | Project Classification | AECO | AEP | APS | ATSI | BGE | ComEd | DAY | DEOK | DLCO | Dominion | DPL | EKPC | JCPL | Met-Ed | PECO | PENELEC | Pepco | PPL | PSEG | RECO | Total |
| In Service | New Generation | 1 | 4 | 1 | 2 | 2 | 1 | 0 | 2 | 0 | 6 | 2 | 0 | 7 | 3 | 4 | 1 | 3 | 9 | 5 | 0 | 53 |
| | Upgrade | 2 | 8 | 5 | 1 | 0 | 3 | 0 | 0 | 0 | 12 | 5 | 0 | 4 | 1 | 9 | 3 | 2 | 5 | 13 | 0 | 73 |
| Under Construction | New Generation | 1 | 0 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 0 | 0 | 0 | 1 | 1 | 1 | 1 | 1 | 1 | 0 | 9 |
| | Upgrade | 0 | 0 | 0 | 2 | 0 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 3 | 1 | 1 | 2 | 1 | 0 | 12 |
| Suspended | New Generation | 1 | 2 | 3 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 1 | 0 | 0 | 0 | 8 |
| | Upgrade | 0 | 0 | 3 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 0 | 2 | 0 | 0 | 0 | 6 |
| Withdrawn | New Generation | 19 | 18 | 40 | 11 | 8 | 9 | 0 | 1 | 2 | 16 | 17 | 3 | 24 | 25 | 43 | 39 | 33 | 39 | 52 | 2 | 401 |
| | Upgrade | 6 | 7 | 5 | 3 | 0 | 3 | 0 | 1 | 0 | 7 | 4 | 0 | 5 | 7 | 3 | 5 | 3 | 6 | 15 | 0 | 80 |
| Active | New Generation | 2 | 7 | 4 | 4 | 0 | 9 | 1 | 0 | 0 | 3 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 2 | 4 | 0 | 37 |
| | Upgrade | 3 | 8 | 6 | 2 | 0 | 3 | 0 | 0 | 0 | 6 | 0 | 0 | 5 | 2 | 1 | 2 | 1 | 3 | 1 | 0 | 43 |
| Total Projects | New Generation | 24 | 31 | 49 | 17 | 10 | 19 | 1 | 3 | 2 | 26 | 19 | 3 | 32 | 29 | 48 | 42 | 38 | 51 | 62 | 2 | 508 |
| | Upgrade | 11 | 23 | 19 | 8 | 0 | 10 | 0 | 1 | 0 | 25 | 10 | 0 | 14 | 11 | 16 | 11 | 9 | 16 | 30 | 0 | 214 |

Table 12-28 shows the status of all combined cycle projects by MW that entered PJM generation queues from January 1, 1997 through September 30, 2018, by zone. Of the 46,297.5 MW of combined cycle projects classified either as new generation or upgrade currently active, suspended or under construction in the PJM generation queue, 21,348.5 MW (46.1 percent) are located within AEP, ComEd and APS.

### Table 12-28 Status of all combined cycle queue projects by zone (MW): January 1997 through September 2018

| | | Project MW | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Project Status | Project Classification | AECO | AEP | APS | ATSI | BGE | ComEd | DAY | DEOK | DLCO | Dominion | DPL | EKPC | JCPL | Met-Ed | PECO | PENELEC | Pepco | PPL | PSEG | RECO | Total |
| In Service | New Generation | 650.0 | 3,032.0 | 525.0 | 1,599.0 | 266.0 | 600.0 | 0.0 | 533.0 | 0.0 | 4,173.1 | 319.2 | 0.0 | 1,665.8 | 2,107.0 | 1,905.0 | 850.0 | 1,540.5 | 4,750.0 | 1,880.5 | 0.0 | 26,396.0 |
| | Upgrade | 220.0 | 230.0 | 670.0 | 5.0 | 0.0 | 621.0 | 0.0 | 0.0 | 0.0 | 913.0 | 102.0 | 0.0 | 110.0 | 10.0 | 853.5 | 92.3 | 89.1 | 229.0 | 845.9 | 0.0 | 4,990.8 |
| Under Construction | New Generation | 452.0 | 0.0 | 930.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 1,681.0 | 0.0 | 0.0 | 0.0 | 450.0 | 760.0 | 1,050.0 | 19.5 | 1,000.0 | 568.0 | 0.0 | 6,910.5 |
| | Upgrade | 0.0 | 0.0 | 0.0 | 301.0 | 0.0 | 12.6 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 35.0 | 155.0 | 50.0 | 64.5 | 483.0 | 0.0 | 0.0 | 1,101.1 |
| Suspended | New Generation | 235.0 | 1,579.0 | 2,850.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 163.0 | 894.0 | 0.0 | 0.0 | 0.0 | 5,721.0 |
| | Upgrade | 0.0 | 0.0 | 165.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 451.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 144.1 | 0.0 | 0.0 | 0.0 | 760.1 |
| Withdrawn | New Generation | 6,909.4 | 11,249.5 | 16,982.1 | 6,301.0 | 3,122.1 | 4,631.0 | 0.0 | 134.5 | 665.0 | 10,421.0 | 5,436.4 | 991.8 | 12,552.6 | 13,001.0 | 23,340.0 | 15,931.0 | 20,414.2 | 16,785.7 | 22,496.7 | 6.9 | 191,371.8 |
| | Upgrade | 115.4 | 711.0 | 579.0 | 86.0 | 0.0 | 1,375.0 | 0.0 | 36.0 | 0.0 | 305.3 | 668.0 | 0.0 | 253.0 | 1,742.0 | 240.0 | 1,040.6 | 85.0 | 500.0 | 2,217.9 | 0.0 | 9,954.2 |
| Active | New Generation | 946.0 | 5,595.0 | 1,626.0 | 4,047.0 | 0.0 | 6,549.2 | 1,150.0 | 0.0 | 0.0 | 3,500.0 | 0.0 | 0.0 | 440.0 | 0.0 | 0.0 | 0.0 | 0.0 | 1,515.0 | 3,091.4 | 0.0 | 28,459.6 |
| | Upgrade | 115.6 | 842.0 | 754.7 | 38.0 | 0.0 | 445.0 | 0.0 | 0.0 | 0.0 | 385.1 | 0.0 | 0.0 | 165.0 | 113.9 | 67.0 | 85.0 | 75.0 | 207.8 | 51.1 | 0.0 | 3,345.2 |
| Total Projects | New Generation | 9,192.4 | 21,455.5 | 22,913.1 | 11,947.0 | 3,388.1 | 11,780.2 | 1,150.0 | 667.5 | 665.0 | 19,775.1 | 5,755.6 | 991.8 | 14,658.4 | 15,558.0 | 26,005.0 | 17,994.0 | 22,868.2 | 24,050.7 | 28,036.6 | 6.9 | 258,858.9 |
| | Upgrade | 451.0 | 1,783.0 | 2,168.7 | 430.0 | 0.0 | 2,453.6 | 0.0 | 36.0 | 0.0 | 1,603.4 | 1,221.0 | 0.0 | 528.0 | 1,900.9 | 1,315.5 | 1,267.9 | 457.7 | 1,419.8 | 3,114.9 | 0.0 | 20,151.4 |

## Combustion Turbine - Natural Gas Project Analysis

Table 12-29 shows the status of all combustion turbine natural gas projects by number of projects that entered PJM generation queues from January 1, 1997, through September 30, 2018, by zone. Of the 43 combustion turbine natural gas projects classified either as new generation or upgrade currently active, suspended or under construction in the PJM generation queue, 24 projects (55.8 percent) are located within AEP, ComEd and APS.

### Table 12-29 Status of all combustion turbine - natural gas generation queue projects by zone (number of projects): January 1997 through September 2018

| | | Number of Projects | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Project Status | Project Classification | AECO | AEP | APS | ATSI | BGE | ComEd | DAY | DEOK | DLCO | Dominion | DPL | EKPC | JCPL | Met-Ed | PECO | PENELEC | Pepco | PPL | PSEG | RECO | Total |
| In Service | New Generation | 5 | 0 | 6 | 0 | 3 | 0 | 0 | 0 | 0 | 2 | 7 | 0 | 3 | 0 | 2 | 5 | 2 | 4 | 9 | 0 | 48 |
| | Upgrade | 4 | 7 | 5 | 1 | 0 | 9 | 6 | 0 | 0 | 24 | 7 | 0 | 0 | 1 | 2 | 2 | 3 | 4 | 14 | 0 | 89 |
| Under Construction | New Generation | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 |
| | Upgrade | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 |
| Suspended | New Generation | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 3 | 0 | 0 | 0 | 0 | 3 |
| | Upgrade | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 |
| Withdrawn | New Generation | 1 | 3 | 0 | 0 | 0 | 1 | 0 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 1 | 2 | 0 | 1 | 5 | 0 | 15 |
| | Upgrade | 1 | 1 | 0 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 0 | 1 | 0 | 0 | 0 | 0 | 5 |
| Active | New Generation | 1 | 1 | 0 | 0 | 1 | 2 | 0 | 0 | 0 | 2 | 0 | 1 | 0 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 9 |
| | Upgrade | 1 | 1 | 6 | 1 | 0 | 14 | 0 | 0 | 0 | 5 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 28 |
| Total Projects | New Generation | 7 | 4 | 6 | 0 | 4 | 3 | 0 | 0 | 1 | 5 | 7 | 1 | 3 | 0 | 3 | 11 | 2 | 5 | 14 | 0 | 76 |
| | Upgrade | 6 | 9 | 11 | 3 | 0 | 23 | 6 | 0 | 0 | 29 | 7 | 0 | 2 | 2 | 2 | 3 | 3 | 4 | 14 | 0 | 124 |

Table 12-30 shows the status of all combustion turbine natural gas projects by MW that entered PJM generation queues from January 1, 1997 through September 30, 2018, by zone. Of the 3,577.6 MW of combustion turbine natural gas projects classified either as new generation or upgrade currently active, suspended or under construction in the PJM generation queue, 1,771.0 MW (49.5 percent) are located within AEP, ComEd and APS.

### Table 12-30 Status of all combustion turbine - natural gas queue projects by zone (MW): January 1997 through September 2018

| | | Project MW | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Project Status | Project Classification | AECO | AEP | APS | ATSI | BGE | ComEd | DAY | DEOK | DLCO | Dominion | DPL | EKPC | JCPL | Met-Ed | PECO | PENELEC | Pepco | PPL | PSEG | RECO | Total |
| In Service | New Generation | 360.7 | 0.0 | 1,176.0 | 0.0 | 23.0 | 0.0 | 0.0 | 0.0 | 0.0 | 1,015.0 | 1,491.0 | 0.0 | 522.1 | 0.0 | 559.0 | 371.9 | 5.0 | 150.9 | 925.9 | 0.0 | 6,600.5 |
| | Upgrade | 43.7 | 190.0 | 187.7 | 40.0 | 0.0 | 257.0 | 60.0 | 0.0 | 0.0 | 887.7 | 321.0 | 0.0 | 0.0 | 34.1 | 13.0 | 25.0 | 32.0 | 252.3 | 215.0 | 0.0 | 2,558.5 |
| Under Construction | New Generation | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 205.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 205.0 |
| | Upgrade | 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 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Suspended | New Generation | 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 | 68.8 | 0.0 | 0.0 | 0.0 | 0.0 | 68.8 |
| | Upgrade | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 200.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 200.0 |
| Withdrawn | New Generation | 7.5 | 66.0 | 0.0 | 0.0 | 0.0 | 10.0 | 0.0 | 0.0 | 0.0 | 54.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.5 | 258.0 | 0.0 | 19.9 | 1,140.1 | 0.0 | 1,556.0 |
| | Upgrade | 7.5 | 6.0 | 0.0 | 25.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 235.0 | 0.0 | 0.0 | 0.0 | 0.0 | 273.5 |
| Active | New Generation | 230.0 | 394.0 | 0.0 | 0.0 | 144.6 | 230.0 | 0.0 | 0.0 | 0.0 | 99.2 | 0.0 | 73.0 | 0.0 | 0.0 | 0.0 | 463.0 | 0.0 | 0.0 | 0.0 | 0.0 | 1,633.8 |
| | Upgrade | 158.0 | 19.0 | 120.0 | 70.0 | 0.0 | 1,008.0 | 0.0 | 0.0 | 0.0 | 95.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 1,470.0 |
| Total Projects | New Generation | 598.2 | 460.0 | 1,176.0 | 0.0 | 167.6 | 240.0 | 0.0 | 0.0 | 205.0 | 1,168.2 | 1,491.0 | 73.0 | 522.1 | 0.0 | 559.5 | 1,161.7 | 5.0 | 170.8 | 2,066.0 | 0.0 | 10,064.1 |
| | Upgrade | 209.2 | 215.0 | 307.7 | 135.0 | 0.0 | 1,265.0 | 60.0 | 0.0 | 0.0 | 982.7 | 321.0 | 0.0 | 200.0 | 34.1 | 13.0 | 260.0 | 32.0 | 252.3 | 215.0 | 0.0 | 4,502.0 |

## Wind Project Analysis

Table 12-31 shows the status of all wind generation projects by number of projects that entered PJM generation queues from January 1, 1997, through September 30, 2018, by zone. Of the 80 wind projects to achieve in service status, 46 projects (57.5 percent) are located within AEP, ComEd and APS. Of the 116 wind projects currently active, suspended or under construction in the PJM generation queue, 88 projects (75.9 percent) are located within AEP, ComEd and APS.

**Table 12-31 Status of all wind generation queue projects by zone (number of projects): January 1997 through September 2018**

| | | Number of Projects | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Project Status | Project Classification | AECO | AEP | APS | ATSI | BGE | ComEd | DAY | DEOK | DLCO | Dominion | DPL | EKPC | JCPL | Met-Ed | PECO | PENELEC | Pepco | PPL | PSEG | RECO | Total |
| In Service | New Generation | 1 | 13 | 14 | 0 | 0 | 17 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 23 | 0 | 8 | 0 | 0 | 76 |
| | Upgrade | 0 | 0 | 0 | 0 | 0 | 2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 3 | 0 | 0 | 0 | 0 | 5 |
| Under Construction | New Generation | 0 | 2 | 4 | 0 | 0 | 6 | 0 | 0 | 0 | 4 | 0 | 0 | 0 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 17 |
| | Upgrade | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 2 |
| Suspended | New Generation | 0 | 3 | 3 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 8 |
| | Upgrade | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 |
| Withdrawn | New Generation | 15 | 91 | 40 | 8 | 0 | 95 | 14 | 0 | 0 | 18 | 10 | 1 | 0 | 0 | 0 | 63 | 0 | 42 | 1 | 0 | 398 |
| | Upgrade | 1 | 0 | 6 | 0 | 0 | 3 | 0 | 0 | 0 | 2 | 0 | 0 | 0 | 0 | 0 | 6 | 0 | 2 | 0 | 0 | 20 |
| Active | New Generation | 2 | 25 | 4 | 3 | 0 | 22 | 1 | 0 | 0 | 3 | 1 | 0 | 2 | 0 | 0 | 0 | 0 | 5 | 0 | 0 | 68 |
| | Upgrade | 1 | 3 | 4 | 0 | 0 | 10 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 2 | 0 | 0 | 0 | 0 | 20 |
| Total Projects | New Generation | 18 | 134 | 65 | 11 | 0 | 140 | 15 | 0 | 0 | 26 | 11 | 1 | 2 | 0 | 0 | 88 | 0 | 55 | 1 | 0 | 567 |
| | Upgrade | 2 | 3 | 12 | 0 | 0 | 15 | 0 | 0 | 0 | 3 | 0 | 0 | 0 | 0 | 0 | 11 | 0 | 2 | 0 | 0 | 48 |

Table 12-32 shows the status of all wind projects by MW that entered PJM generation queues from January 1, 1997 through September 30, 2018, by zone. Of the 7,191.6 MW of wind generation capacity to achieve the in service status, 5,956.2 MW (82.8 percent) of nameplate capacity is located within AEP, ComEd and APS. Of the 23,071.3 MW of wind generation capacity currently active, suspended or under construction in the PJM generation queue, 14,603.3 MW of generation capacity (63.3 percent) is located within AEP, ComEd and APS.

Table 12-32 Status of all wind generation queue projects by zone (MW): January 1997 through September 2018

| | | Project MW | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Project Status | Project Classification | AECO | AEP | APS | ATSI | BGE | ComEd | DAY | DEOK | DLCO | Dominion | DPL | EKPC | JCPL | Met-Ed | PECO | PENELEC | Pepco | PPL | PSEG | RECO | Total |
| In Service | New Generation | 7.5 | 2,538.7 | 1,004.0 | 0.0 | 0.0 | 2,413.5 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 1,000.9 | 0.0 | 226.5 | 0.0 | 0.0 | 7,191.1 |
| | Upgrade | 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 | 0.5 | 0.0 | 0.0 | 0.0 | 0.0 | 0.5 |
| Under Construction | New Generation | 0.0 | 450.0 | 348.6 | 0.0 | 0.0 | 1,228.5 | 0.0 | 0.0 | 0.0 | 714.8 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 70.0 | 0.0 | 0.0 | 0.0 | 0.0 | 2,811.9 |
| | Upgrade | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 32.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 32.0 |
| Suspended | New Generation | 0.0 | 380.0 | 375.1 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 76.6 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 100.0 | 0.0 | 0.0 | 0.0 | 0.0 | 931.7 |
| | Upgrade | 0.0 | 0.0 | 16.3 | 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 | 0.0 | 0.0 | 16.3 |
| Withdrawn | New Generation | 3,626.4 | 18,670.8 | 3,052.1 | 1,295.6 | 0.0 | 22,521.7 | 2,028.0 | 0.0 | 0.0 | 2,588.1 | 2,816.8 | 150.3 | 0.0 | 0.0 | 0.0 | 5,277.0 | 0.0 | 3,066.3 | 20.0 | 0.0 | 65,113.0 |
| | Upgrade | 0.0 | 0.0 | 100.0 | 0.0 | 0.0 | 5.7 | 0.0 | 0.0 | 0.0 | 82.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 243.4 | 0.0 | 6.0 | 0.0 | 0.0 | 437.0 |
| Active | New Generation | 614.0 | 5,189.3 | 350.0 | 816.1 | 0.0 | 4,775.5 | 100.0 | 0.0 | 0.0 | 2,400.3 | 247.8 | 0.0 | 2,640.0 | 0.0 | 0.0 | 0.0 | 0.0 | 531.1 | 0.0 | 0.0 | 17,663.9 |
| | Upgrade | 5.0 | 500.0 | 94.4 | 0.0 | 0.0 | 895.7 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 120.3 | 0.0 | 0.0 | 0.0 | 0.0 | 1,615.5 |
| Total Projects | New Generation | 4,247.9 | 27,228.8 | 5,129.8 | 2,111.7 | 0.0 | 30,939.1 | 2,128.0 | 0.0 | 0.0 | 5,779.8 | 3,064.6 | 150.3 | 2,640.0 | 0.0 | 0.0 | 6,447.9 | 0.0 | 3,823.9 | 20.0 | 0.0 | 93,711.6 |
| | Upgrade | 5.0 | 500.0 | 210.7 | 0.0 | 0.0 | 901.4 | 0.0 | 0.0 | 0.0 | 114.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 364.2 | 0.0 | 6.0 | 0.0 | 0.0 | 2,101.3 |

## Solar Project Analysis

Table 12-33 shows the status of all solar generation projects by number of projects that entered PJM generation queues from January 1, 1997, through September 30, 2018, by zone. Of the 143 solar projects to achieve in service status, 9 projects (6.3 percent) are located within AEP, ComEd and APS. Of the 403 solar projects currently active, suspended or under construction in the PJM generation queue, 127 projects (31.5 percent) are located within AEP, ComEd and APS.

Table 12-33 Status of all solar generation queue projects by zone (number of projects): January 1997 through September 2018

| | | Number of Projects | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Project Status | Project Classification | AECO | AEP | APS | ATSI | BGE | ComEd | DAY | DEOK | DLCO | Dominion | DPL | EKPC | JCPL | Met-Ed | PECO | PENELEC | Pepco | PPL | PSEG | RECO | Total |
| In Service | New Generation | 7 | 4 | 4 | 0 | 1 | 1 | 1 | 0 | 0 | 17 | 9 | 0 | 41 | 0 | 1 | 0 | 0 | 2 | 39 | 0 | 127 |
| | Upgrade | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 2 | 8 | 0 | 6 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 16 |
| Under Construction | New Generation | 0 | 1 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 4 | 4 | 0 | 5 | 0 | 0 | 0 | 0 | 0 | 6 | 0 | 21 |
| | Upgrade | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 2 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 3 |
| Suspended | New Generation | 0 | 3 | 19 | 0 | 0 | 0 | 1 | 0 | 0 | 2 | 0 | 0 | 5 | 0 | 0 | 1 | 0 | 0 | 1 | 0 | 32 |
| | Upgrade | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 |
| Withdrawn | New Generation | 159 | 71 | 58 | 8 | 12 | 27 | 14 | 12 | 0 | 137 | 114 | 3 | 167 | 12 | 6 | 12 | 13 | 27 | 67 | 0 | 919 |
| | Upgrade | 2 | 2 | 1 | 0 | 0 | 2 | 0 | 0 | 0 | 8 | 1 | 0 | 8 | 0 | 0 | 0 | 0 | 0 | 1 | 0 | 25 |
| Active | New Generation | 10 | 75 | 9 | 7 | 0 | 19 | 11 | 3 | 1 | 136 | 41 | 5 | 4 | 5 | 1 | 4 | 6 | 2 | 10 | 1 | 350 |
| | Upgrade | 0 | 5 | 1 | 1 | 0 | 0 | 1 | 2 | 1 | 19 | 1 | 0 | 1 | 2 | 0 | 0 | 0 | 1 | 0 | 0 | 35 |
| Total Projects | New Generation | 176 | 154 | 91 | 15 | 13 | 47 | 27 | 15 | 1 | 296 | 168 | 8 | 222 | 17 | 8 | 17 | 19 | 31 | 123 | 1 | 1,449 |
| | Upgrade | 2 | 7 | 2 | 1 | 0 | 2 | 1 | 2 | 1 | 32 | 11 | 0 | 15 | 2 | 0 | 0 | 0 | 1 | 1 | 0 | 80 |

Table 12-34 shows the status of all solar projects by MW that entered PJM generation queues from January 1, 1997 through September 30, 2018, by zone. Of the 1,318.7 MW of solar generation capacity to achieve in service status, 76.7 MW (5.8 percent) of nameplate capacity is located within AEP, ComEd and APS. Of the 25,753.5 MW of solar generation capacity currently active, suspended or under construction in the PJM generation queue, 9,404.3 MW of generation capacity (36.5 percent) is located within AEP, ComEd and APS.

**Table 12-34 Status of all solar generation queue projects by zone (MW): January 1997 through September 2018**

| | | Project MW | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Project Status | Project Classification | AECO | AEP | APS | ATSI | BGE | ComEd | DAY | DEOK | DLCO | Dominion | DPL | EKPC | JCPL | Met-Ed | PECO | PENELEC | Pepco | PPL | PSEG | RECO | Total |
| In Service | New Generation | 57.3 | 14.7 | 53.0 | 0.0 | 1.1 | 9.0 | 2.5 | 0.0 | 0.0 | 546.2 | 118.4 | 0.0 | 285.3 | 0.0 | 3.3 | 0.0 | 0.0 | 15.0 | 193.5 | 0.0 | 1,299.3 |
| | Upgrade | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 3.1 | 0.0 | 0.0 | 16.3 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 19.4 |
| Under Construction | New Generation | 0.0 | 20.0 | 10.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 295.8 | 37.0 | 0.0 | 81.9 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 30.1 | 0.0 | 474.8 |
| | Upgrade | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 13.9 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 13.9 |
| Suspended | New Generation | 0.0 | 20.0 | 313.3 | 0.0 | 0.0 | 0.0 | 20.0 | 0.0 | 0.0 | 24.8 | 0.0 | 0.0 | 37.6 | 0.0 | 0.0 | 3.0 | 0.0 | 0.0 | 6.0 | 0.0 | 424.7 |
| | Upgrade | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 19.8 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 19.8 |
| Withdrawn | New Generation | 1,665.3 | 3,261.6 | 1,486.4 | 216.1 | 53.3 | 1,338.8 | 523.9 | 279.4 | 0.0 | 7,867.0 | 1,516.7 | 189.9 | 1,348.8 | 467.0 | 51.4 | 121.7 | 175.8 | 283.7 | 451.9 | 0.0 | 21,298.8 |
| | Upgrade | 10.0 | 106.0 | 0.0 | 0.0 | 0.0 | 20.0 | 0.0 | 0.0 | 0.0 | 341.0 | 0.0 | 0.0 | 23.8 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 1.3 | 0.0 | 502.1 |
| Active | New Generation | 48.3 | 6,497.0 | 432.5 | 920.9 | 0.0 | 1,679.5 | 1,096.5 | 295.0 | 11.7 | 9,647.2 | 1,345.0 | 325.0 | 26.6 | 190.0 | 18.0 | 243.9 | 76.3 | 30.0 | 49.3 | 40.0 | 22,972.6 |
| | Upgrade | 0.0 | 357.0 | 75.0 | 20.0 | 0.0 | 0.0 | 20.0 | 85.0 | 8.3 | 1,214.0 | 20.0 | 0.0 | 8.5 | 40.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 1,847.8 |
| Total Projects | New Generation | 1,770.9 | 9,813.3 | 2,295.2 | 1,137.0 | 54.4 | 3,027.3 | 1,642.9 | 574.4 | 11.7 | 18,381.0 | 3,017.1 | 514.9 | 1,780.2 | 657.0 | 72.7 | 368.6 | 252.1 | 328.7 | 730.9 | 40.0 | 46,470.1 |
| | Upgrade | 10.0 | 463.0 | 75.0 | 20.0 | 0.0 | 20.0 | 20.0 | 85.0 | 8.3 | 1,591.8 | 20.0 | 0.0 | 48.6 | 40.0 | 0.0 | 0.0 | 0.0 | 0.0 | 1.3 | 0.0 | 2,403.0 |

## Relationship Between Project Developer and Transmission Owner

A transmission owner (TO) is an "entity that owns, leases or otherwise has a possessory interest in facilities used for the transmission of electric energy in interstate commerce under the tariff."[32] Where the transmission owner is a vertically integrated company that also owns generation, there is a potential conflict of interest when the transmission owner evaluates the interconnection requirements of new generation which is a competitor to the generation of the parent company and when the transmission owner evaluates the interconnection requirements of new generation which is part of the same company as the transmission owner. There is also a potential conflict of interest when the transmission owner evaluates the interconnection requirements of a merchant transmission developer which is a competitor of the transmission owner. The MMU recommends outsourcing interconnection studies to an independent party to avoid potential conflicts of interest.

Table 12-35 shows the relationship between the project developer and Transmission Owner for all project MW that have entered the PJM generation queue from January 1, 1997, through September 30, 2018, by transmission owner and unit type. A project where the developer is affiliated with the Transmission Owner is classified as related. A project where the developer is not affiliated with the Transmission Owner is classified as unrelated. For example, 36.0 MW of combined cycle generation projects that have entered the PJM generation queue in DEOK were projects developed by Duke Energy or subsidiaries of Duke Energy, the Transmission Owner for DEOK. These project MW are classified as related. There have been 667.5 MW of combined cycle projects that have entered the PJM generation queue in DEOK by developers not affiliated with Duke Energy. These project MW are classified as "unrelated." Of the 504,007.2 MW that have entered the queue during the time period of January 1, 1997, through September 30, 2018, 62,259.9 MW (12.4 percent) have been submitted by Transmission Owners building in their own service territory.

32 See OATT § 1 (Transmission Owner).

**Table 12-35 Relationship between project developer and Transmission Owner for all interconnection queue projects MW by unit type: September 30, 2018**

| | | | | MW by Unit Type | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Parent Company | Transmission Owner | Related to Developer | Number of Projects | Battery | CC | CT - Natural Gas | CT - Oil | CT - Other | Fuel Cell | Hydro - Pumped Storage | Hydro - Run of River | Nuclear | RICE - Natural Gas | RICE - Oil | RICE - Other | Solar | Steam - Coal | Steam - Natural Gas | Steam - Oil | Steam - Other | Wind | Total |
| AEP | AEP | Related | 47 | 16.0 | 680.0 | 0.0 | 0.0 | 0.0 | 0.0 | 34.0 | 0.0 | 214.0 | 0.0 | 0.0 | 0.0 | 142.7 | 3,918.0 | 90.0 | 0.0 | 0.0 | 0.0 | 5,094.7 |
| | | Unrelated | 458 | 356.0 | 22,558.5 | 675.0 | 7.5 | 127.3 | 0.0 | 0.0 | 448.4 | 0.0 | 12.0 | 0.0 | 75.4 | 10,133.6 | 10,368.0 | 0.0 | 0.0 | 492.0 | 27,728.8 | 72,982.4 |
| AES | DAY | Related | 13 | 20.0 | 0.0 | 38.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 21.5 | 1,347.5 | 0.0 | 0.0 | 0.0 | 0.0 | 1,427.0 |
| | | Unrelated | 49 | 39.9 | 1,150.0 | 22.0 | 0.0 | 1.9 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 10.0 | 1,641.4 | 0.0 | 0.0 | 0.0 | 0.0 | 2,128.0 | 4,993.2 |
| DLCO | DLCO | Related | 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 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | | Unrelated | 22 | 20.0 | 665.0 | 205.0 | 40.0 | 19.2 | 0.0 | 0.0 | 106.0 | 1,879.0 | 0.0 | 0.0 | 0.0 | 20.0 | 2,810.0 | 0.0 | 0.0 | 0.0 | 0.0 | 5,764.2 |
| Dominion | Dominion | Related | 93 | 0.0 | 12,334.0 | 914.2 | 100.0 | 0.0 | 0.0 | 340.0 | 5.5 | 1,944.0 | 0.0 | 0.0 | 60.0 | 901.6 | 301.0 | 0.0 | 0.0 | 4.0 | 146.0 | 17,050.3 |
| | | Unrelated | 426 | 115.0 | 9,044.5 | 1,236.7 | 0.5 | 227.3 | 0.0 | 0.0 | 29.5 | 0.0 | 0.0 | 10.0 | 119.4 | 19,071.2 | 20.0 | 0.0 | 0.0 | 316.3 | 5,747.8 | 35,938.2 |
| Duke | DEOK | Related | 7 | 23.8 | 36.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 6.4 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 66.2 |
| | | Unrelated | 25 | 16.0 | 667.5 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 112.0 | 0.0 | 0.0 | 0.0 | 4.8 | 653.0 | 120.0 | 0.0 | 0.0 | 0.0 | 0.0 | 1,573.3 |
| EKPC | EKPC | Related | 2 | 0.0 | 821.8 | 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 | 0.0 | 821.8 |
| | | Unrelated | 11 | 0.0 | 170.0 | 73.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 514.9 | 0.0 | 0.0 | 0.0 | 0.0 | 150.3 | 908.2 |
| Exelon | AECO | Related | 5 | 0.0 | 730.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 8.3 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 738.3 |
| | | Unrelated | 278 | 71.0 | 8,913.4 | 807.4 | 380.0 | 20.7 | 2.8 | 0.0 | 0.0 | 0.0 | 2.0 | 5.0 | 10.3 | 1,772.6 | 15.0 | 5.5 | 0.0 | 10.0 | 4,252.9 | 16,268.6 |
| | BGE | Related | 14 | 20.0 | 376.0 | 10.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 108.5 | 0.0 | 0.0 | 8.5 | 20.0 | 10.0 | 101.0 | 0.0 | 0.0 | 0.0 | 654.0 |
| | | Unrelated | 56 | 40.6 | 3,012.1 | 157.6 | 18.0 | 133.0 | 0.0 | 0.0 | 0.4 | 3,280.0 | 1.3 | 0.0 | 0.0 | 34.4 | 0.0 | 2.5 | 0.0 | 25.0 | 0.0 | 6,704.9 |
| | ComEd | Related | 16 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 1,185.0 | 0.0 | 0.0 | 0.0 | 9.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 1,194.0 |
| | | Unrelated | 319 | 406.7 | 14,233.8 | 1,505.0 | 42.0 | 65.2 | 0.0 | 0.0 | 22.7 | 0.0 | 35.0 | 0.0 | 67.7 | 3,038.3 | 1,926.0 | 91.0 | 0.0 | 90.0 | 31,840.5 | 53,363.9 |
| | DPL | Related | 7 | 0.0 | 1,365.0 | 351.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 7.4 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 1,723.4 |
| | | Unrelated | 277 | 122.0 | 5,611.6 | 1,461.0 | 600.9 | 42.6 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 84.6 | 3,029.7 | 653.0 | 15.0 | 0.0 | 65.0 | 3,064.6 | 14,750.0 |
| | PECO | Related | 33 | 40.0 | 6,965.0 | 5.0 | 89.5 | 0.0 | 0.0 | 0.0 | 265.0 | 437.8 | 0.0 | 0.0 | 0.0 | 0.0 | 7.0 | 0.0 | 0.0 | 0.0 | 0.0 | 7,809.3 |
| | | Unrelated | 78 | 5.3 | 20,355.5 | 567.5 | 2.0 | 15.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 17.0 | 3.7 | 72.7 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 21,038.7 |
| | Pepco | Related | 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 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | | Unrelated | 82 | 20.0 | 23,325.9 | 37.0 | 30.0 | 9.0 | 0.0 | 0.0 | 0.0 | 1,640.0 | 32.0 | 0.0 | 3.5 | 252.1 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 25,349.5 |
| First Energy | APS | Related | 4 | 0.0 | 1,453.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 1,710.0 | 0.0 | 0.0 | 0.0 | 0.0 | 3,163.0 |
| | | Unrelated | 344 | 330.9 | 23,628.8 | 1,483.7 | 0.0 | 84.4 | 0.0 | 0.0 | 623.3 | 0.0 | 140.0 | 53.8 | 25.4 | 2,370.2 | 4,092.0 | 0.0 | 0.0 | 184.4 | 5,340.5 | 38,357.4 |
| | ATSI | Related | 6 | 0.0 | 1,678.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 16.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 1,694.0 |
| | | Unrelated | 71 | 56.1 | 10,699.0 | 135.0 | 5.0 | 166.4 | 0.0 | 0.0 | 0.0 | 0.0 | 59.7 | 0.0 | 6.9 | 1,157.0 | 0.0 | 16.5 | 0.0 | 0.0 | 2,111.7 | 14,413.3 |
| | JCPL | Related | 2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 20.0 | 0.0 | 0.0 | 0.0 | 0.0 | 12.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 32.0 |
| | | Unrelated | 340 | 334.2 | 15,186.4 | 722.1 | 0.0 | 4.8 | 0.8 | 0.0 | 1.6 | 0.0 | 0.6 | 0.0 | 12.8 | 1,816.7 | 0.0 | 0.0 | 0.0 | 30.0 | 2,640.0 | 20,750.0 |
| | Met-Ed | Related | 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 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | | Unrelated | 86 | 23.0 | 17,458.9 | 34.1 | 1,196.0 | 52.1 | 0.0 | 0.0 | 0.0 | 79.0 | 0.0 | 8.0 | 15.2 | 697.0 | 0.0 | 0.0 | 0.0 | 24.0 | 0.0 | 19,587.3 |
| | PENELEC | Related | 4 | 0.0 | 534.0 | 5.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 1,860.0 | 0.0 | 0.0 | 0.0 | 0.0 | 2,399.0 |
| | | Unrelated | 246 | 97.4 | 18,727.9 | 1,416.7 | 0.9 | 214.4 | 0.0 | 16.0 | 46.3 | 14.0 | 341.8 | 8.0 | 22.8 | 368.6 | 561.0 | 590.0 | 0.0 | 585.0 | 6,812.0 | 29,822.6 |
| PPL | PPL | Related | 21 | 0.0 | 2,294.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 109.0 | 1,600.0 | 0.0 | 0.0 | 0.0 | 0.0 | 111.0 | 0.0 | 0.0 | 0.0 | 0.0 | 4,114.0 |
| | | Unrelated | 226 | 520.0 | 23,176.5 | 423.1 | 8.0 | 234.5 | 0.0 | 1,000.0 | 142.6 | 388.0 | 19.9 | 2.4 | 44.7 | 328.7 | 6,896.6 | 0.0 | 0.0 | 31.0 | 3,829.9 | 37,045.9 |
| PSEG | PSEG | Related | 106 | 0.0 | 11,836.1 | 1,818.1 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 381.0 | 0.0 | 0.0 | 0.0 | 175.8 | 24.0 | 44.0 | 0.0 | 0.0 | 0.0 | 14,279.0 |
| | | Unrelated | 192 | 14.5 | 19,315.4 | 462.9 | 608.0 | 62.5 | 4.9 | 0.0 | 1,000.0 | 0.0 | 10.6 | 0.0 | 13.7 | 556.4 | 0.0 | 20.0 | 0.0 | 0.0 | 20.0 | 22,088.9 |
| Con Ed | RECO | Related | 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 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | | Unrelated | 3 | 0.0 | 6.9 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 40.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 46.9 |
| Total | | Related | 380 | 119.8 | 41,102.9 | 3,141.3 | 189.5 | 0.0 | 0.0 | 374.0 | 399.5 | 5,886.3 | 0.0 | 0.0 | 68.5 | 1,304.6 | 9,288.5 | 235.0 | 0.0 | 4.0 | 146.0 | 62,259.9 |
| | | Unrelated | 3589 | 2,588.6 | 237,907.4 | 11,424.8 | 2,938.8 | 1,480.3 | 8.5 | 1,016.0 | 2,532.8 | 7,280.0 | 654.9 | 104.2 | 520.9 | 47,568.4 | 27,461.6 | 740.5 | 0.0 | 1,852.7 | 95,666.9 | 441,747.3 |

## Combined Cycle Project Developer and Transmission Owner Relationships

Table 12-36 shows the relationship between the project developer and Transmission Owner for all combined cycle project MW that have entered the PJM generation queue from January 1, 1997 through September 30, 2018, by transmission owner and project status. Of the 39,398.4 combined cycle project MW that have achieved in service or under construction status during this time period, 9,375.0 MW (23.8 percent) have been developed by Transmission Owners building in their own service territory.

### Table 12-36 Relationship between project developer and transmission owner for all combined cycle project MW in PJM interconnection queue: September 30, 2018

| | | | MW by Project Status | | | | | |
|---|---|---|---|---|---|---|---|---|
| Parent Company | Transmission Owner | Related to Developer | Active | In Service | Under Construction | Suspended | Withdrawn | Total |
| AEP | AEP | Related | 100.0 | 580.0 | 0.0 | 0.0 | 0.0 | 680.0 |
| | | Unrelated | 6,337.0 | 2,682.0 | 0.0 | 1,579.0 | 11,960.5 | 22,558.5 |
| AES | DAY | Related | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | | Unrelated | 1,150.0 | 0.0 | 0.0 | 0.0 | 0.0 | 1,150.0 |
| DLCO | DLCO | Related | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | | Unrelated | 0.0 | 0.0 | 0.0 | 0.0 | 665.0 | 665.0 |
| Dominion | Dominion | Related | 25.0 | 3,152.0 | 1,681.0 | 0.0 | 7,476.0 | 12,334.0 |
| | | Unrelated | 3,860.1 | 1,934.1 | 0.0 | 0.0 | 3,250.3 | 9,044.5 |
| Duke | DEOK | Related | 0.0 | 0.0 | 0.0 | 0.0 | 36.0 | 36.0 |
| | | Unrelated | 0.0 | 533.0 | 0.0 | 0.0 | 134.5 | 667.5 |
| EKPC | EKPC | Related | 0.0 | 0.0 | 0.0 | 0.0 | 821.8 | 821.8 |
| | | Unrelated | 0.0 | 0.0 | 0.0 | 0.0 | 170.0 | 170.0 |
| Exelon | AECO | Related | 0.0 | 0.0 | 0.0 | 0.0 | 730.0 | 730.0 |
| | | Unrelated | 1,061.6 | 870.0 | 452.0 | 235.0 | 6,294.8 | 8,913.4 |
| | BGE | Related | 0.0 | 256.0 | 0.0 | 0.0 | 120.0 | 376.0 |
| | | Unrelated | 0.0 | 10.0 | 0.0 | 0.0 | 3,002.1 | 3,012.1 |
| | ComEd | Related | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | | Unrelated | 6,994.2 | 1,221.0 | 12.6 | 0.0 | 6,006.0 | 14,233.8 |
| | DPL | Related | 0.0 | 60.0 | 0.0 | 0.0 | 1,305.0 | 1,365.0 |
| | | Unrelated | 0.0 | 361.2 | 0.0 | 451.0 | 4,799.4 | 5,611.6 |
| | PECO | Related | 0.0 | 0.0 | 0.0 | 0.0 | 6,965.0 | 6,965.0 |
| | | Unrelated | 67.0 | 2,758.5 | 915.0 | 0.0 | 16,615.0 | 20,355.5 |
| | Pepco | Related | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | | Unrelated | 75.0 | 1,629.6 | 84.0 | 1,038.1 | 20,499.2 | 23,325.9 |
| First Energy | APS | Related | 0.0 | 525.0 | 0.0 | 0.0 | 928.0 | 1,453.0 |
| | | Unrelated | 2,380.7 | 670.0 | 930.0 | 3,015.0 | 16,633.1 | 23,628.8 |
| | ATSI | Related | 0.0 | 0.0 | 0.0 | 0.0 | 1,678.0 | 1,678.0 |
| | | Unrelated | 4,085.0 | 1,604.0 | 301.0 | 0.0 | 4,709.0 | 10,699.0 |
| | JCPL | Related | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | | Unrelated | 605.0 | 1,775.8 | 0.0 | 0.0 | 12,805.6 | 15,186.4 |
| | Met-Ed | Related | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | | Unrelated | 113.9 | 2,117.0 | 485.0 | 0.0 | 14,743.0 | 17,458.9 |
| | PENELEC | Related | 0.0 | 0.0 | 0.0 | 0.0 | 534.0 | 534.0 |
| | | Unrelated | 85.0 | 942.3 | 1,100.0 | 163.0 | 16,437.6 | 18,727.9 |
| PPL | PPL | Related | 0.0 | 633.0 | 0.0 | 0.0 | 1,661.0 | 2,294.0 |
| | | Unrelated | 1,722.8 | 4,346.0 | 1,483.0 | 0.0 | 15,624.7 | 23,176.5 |
| PSEG | PSEG | Related | 51.1 | 1,920.0 | 568.0 | 0.0 | 9,297.0 | 11,836.1 |
| | | Unrelated | 3,091.4 | 806.4 | 0.0 | 0.0 | 15,417.6 | 19,315.4 |
| Con Ed | RECO | Related | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | | Unrelated | 0.0 | 0.0 | 0.0 | 0.0 | 6.9 | 6.9 |
| Total | | Related | 176.1 | 7,126.0 | 2,249.0 | 0.0 | 31,551.8 | 41,102.9 |
| | | Unrelated | 31,628.7 | 24,260.8 | 5,762.6 | 6,481.1 | 169,774.1 | 237,907.4 |

## Combustion Turbine – Natural Gas Project Developer and Transmission Owner Relationships

Table 12-37 shows the relationship between the project developer and Transmission Owner for all CT – natural gas project MW that have entered the PJM generation queue from January 1, 1997 through September 30, 2018, by transmission owner and project status. Of the 9,364.0 CT – natural gas project MW that have achieved in service or under construction status during this time period, 2,107.0 (22.5 percent) have been developed by Transmission Owners building in their own service territory.

### Table 12-37 Relationship between project developer and transmission owner for all CT – natural gas project MW in PJM interconnection queue: September 30, 2018

| | | | MW by Project Status | | | | | |
|---|---|---|---|---|---|---|---|---|
| Parent Company | Transmission Owner | Related to Developer | Active | In Service | Under Construction | Suspended | Withdrawn | Total |
| AEP | AEP | Related | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | | Unrelated | 413.0 | 190.0 | 0.0 | 0.0 | 72.0 | 675.0 |
| AES | DAY | Related | 0.0 | 38.0 | 0.0 | 0.0 | 0.0 | 38.0 |
| | | Unrelated | 0.0 | 22.0 | 0.0 | 0.0 | 0.0 | 22.0 |
| DLCO | DLCO | Related | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | | Unrelated | 0.0 | 0.0 | 205.0 | 0.0 | 0.0 | 205.0 |
| Dominion | Dominion | Related | 128.2 | 786.0 | 0.0 | 0.0 | 0.0 | 914.2 |
| | | Unrelated | 66.0 | 1,116.7 | 0.0 | 0.0 | 54.0 | 1,236.7 |
| Duke | DEOK | Related | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | | Unrelated | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| EKPC | EKPC | Related | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | | Unrelated | 73.0 | 0.0 | 0.0 | 0.0 | 0.0 | 73.0 |
| Exelon | AECO | Related | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | | Unrelated | 388.0 | 404.4 | 0.0 | 0.0 | 15.0 | 807.4 |
| | BGE | Related | 0.0 | 10.0 | 0.0 | 0.0 | 0.0 | 10.0 |
| | | Unrelated | 144.6 | 13.0 | 0.0 | 0.0 | 0.0 | 157.6 |
| | ComEd | Related | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | | Unrelated | 1,238.0 | 257.0 | 0.0 | 0.0 | 10.0 | 1,505.0 |
| | DPL | Related | 0.0 | 351.0 | 0.0 | 0.0 | 0.0 | 351.0 |
| | | Unrelated | 0.0 | 1,461.0 | 0.0 | 0.0 | 0.0 | 1,461.0 |
| | PECO | Related | 0.0 | 5.0 | 0.0 | 0.0 | 0.0 | 5.0 |
| | | Unrelated | 0.0 | 567.0 | 0.0 | 0.0 | 0.5 | 567.5 |
| | Pepco | Related | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | | Unrelated | 0.0 | 37.0 | 0.0 | 0.0 | 0.0 | 37.0 |
| First Energy | APS | Related | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | | Unrelated | 120.0 | 1,363.7 | 0.0 | 0.0 | 0.0 | 1,483.7 |
| | ATSI | Related | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | | Unrelated | 70.0 | 40.0 | 0.0 | 0.0 | 25.0 | 135.0 |
| | JCPL | Related | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | | Unrelated | 0.0 | 522.1 | 0.0 | 200.0 | 0.0 | 722.1 |
| | Met-Ed | Related | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | | Unrelated | 0.0 | 34.1 | 0.0 | 0.0 | 0.0 | 34.1 |
| | PENELEC | Related | 0.0 | 5.0 | 0.0 | 0.0 | 0.0 | 5.0 |
| | | Unrelated | 463.0 | 391.9 | 0.0 | 68.8 | 493.0 | 1,416.7 |
| PPL | PPL | Related | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | | Unrelated | 0.0 | 403.2 | 0.0 | 0.0 | 19.9 | 423.1 |
| PSEG | PSEG | Related | 0.0 | 912.0 | 0.0 | 0.0 | 906.1 | 1,818.1 |
| | | Unrelated | 0.0 | 228.9 | 0.0 | 0.0 | 234.0 | 462.9 |
| Con Ed | RECO | Related | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | | Unrelated | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Total | | Related | 128.2 | 2,107.0 | 0.0 | 0.0 | 906.1 | 3,141.3 |
| | | Unrelated | 2,975.6 | 7,052.0 | 205.0 | 268.8 | 923.4 | 11,424.8 |

## Wind Project Developer and Transmission Owner Relationships

Table 12-38 shows the relationship between the project developer and Transmission Owner for all wind project MW that have entered the PJM generation queue from January 1, 1997 through September 30, 2018, by transmission owner and project status. Of the 10,035.5 wind project MW that have achieved in service or under construction status during this time period, 12.0 MW (0.1 percent) have been developed by Transmission Owners building in their own service territory.

### Table 12-38 Relationship between project developer and transmission owner for all wind project MW in PJM interconnection queue: September 30, 2018

| | | | MW by Project Status | | | | | |
|---|---|---|---|---|---|---|---|---|
| Parent Company | Transmission Owner | Related to Developer | Active | In Service | Under Construction | Suspended | Withdrawn | Total |
| AEP | AEP | Related | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | | Unrelated | 5,689.3 | 2,538.7 | 450.0 | 380.0 | 18,670.8 | 27,728.8 |
| AES | DAY | Related | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | | Unrelated | 100.0 | 0.0 | 0.0 | 0.0 | 2,028.0 | 2,128.0 |
| DLCO | DLCO | Related | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | | Unrelated | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Dominion | Dominion | Related | 0.0 | 0.0 | 12.0 | 0.0 | 134.0 | 146.0 |
| | | Unrelated | 2,400.3 | 0.0 | 734.8 | 76.6 | 2,536.1 | 5,747.8 |
| Duke | DEOK | Related | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | | Unrelated | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| EKPC | EKPC | Related | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | | Unrelated | 0.0 | 0.0 | 0.0 | 0.0 | 150.3 | 150.3 |
| Exelon | AECO | Related | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | | Unrelated | 619.0 | 7.5 | 0.0 | 0.0 | 3,626.4 | 4,252.9 |
| | BGE | Related | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | | Unrelated | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | ComEd | Related | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | | Unrelated | 5,671.2 | 2,413.5 | 1,228.5 | 0.0 | 22,527.3 | 31,840.5 |
| | DPL | Related | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | | Unrelated | 247.8 | 0.0 | 0.0 | 0.0 | 2,816.8 | 3,064.6 |
| | PECO | Related | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | | Unrelated | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | Pepco | Related | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | | Unrelated | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| First Energy | APS | Related | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | | Unrelated | 444.4 | 1,004.0 | 348.6 | 391.4 | 3,152.1 | 5,340.5 |
| | ATSI | Related | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | | Unrelated | 816.1 | 0.0 | 0.0 | 0.0 | 1,295.6 | 2,111.7 |
| | JCPL | Related | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | | Unrelated | 2,640.0 | 0.0 | 0.0 | 0.0 | 0.0 | 2,640.0 |
| | Met-Ed | Related | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | | Unrelated | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | PENELEC | Related | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | | Unrelated | 120.3 | 1,001.4 | 70.0 | 100.0 | 5,520.3 | 6,812.0 |
| PPL | PPL | Related | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | | Unrelated | 531.1 | 226.5 | 0.0 | 0.0 | 3,072.3 | 3,829.9 |
| PSEG | PSEG | Related | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | | Unrelated | 0.0 | 0.0 | 0.0 | 0.0 | 20.0 | 20.0 |
| Con Ed | RECO | Related | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | | Unrelated | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Total | | Related | 0.0 | 0.0 | 12.0 | 0.0 | 134.0 | 146.0 |
| | | Unrelated | 19,279.4 | 7,191.6 | 2,831.9 | 948.0 | 65,416.0 | 95,666.9 |

## Solar Project Developer and Transmission Owner Relationships

Table 12-39 shows the relationship between the project developer and Transmission Owner for all solar project MW that have entered the PJM generation queue from January 1, 1997 through September 30, 2018, by transmission owner and project status. Of the 1,807.4 solar project MW that have achieved in service or under construction status during this time period, 440.6 MW (24.4 percent) have been developed by Transmission Owners building in their own service territory.

### Table 12-39 Relationship between project developer and transmission owner for all solar project MW in PJM interconnection queue: September 30, 2018

| | | | MW by Project Status | | | | | |
|---|---|---|---|---|---|---|---|---|
| Parent Company | Transmission Owner | Related to Developer | Active | In Service | Under Construction | Suspended | Withdrawn | Total |
| AEP | AEP | Related | 68.0 | 14.7 | 0.0 | 10.0 | 50.0 | 142.7 |
| | | Unrelated | 6,786.0 | 0.0 | 20.0 | 10.0 | 3,317.6 | 10,133.6 |
| AES | DAY | Related | 0.0 | 0.0 | 0.0 | 0.0 | 21.5 | 21.5 |
| | | Unrelated | 1,116.5 | 2.5 | 0.0 | 20.0 | 502.4 | 1,641.4 |
| DLCO | DLCO | Related | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | | Unrelated | 20.0 | 0.0 | 0.0 | 0.0 | 0.0 | 20.0 |
| Dominion | Dominion | Related | 375.3 | 294.4 | 0.0 | 0.0 | 231.9 | 901.6 |
| | | Unrelated | 10,485.9 | 254.9 | 309.7 | 44.6 | 7,976.1 | 19,071.2 |
| Duke | DEOK | Related | 0.0 | 0.0 | 0.0 | 0.0 | 6.4 | 6.4 |
| | | Unrelated | 380.0 | 0.0 | 0.0 | 0.0 | 273.0 | 653.0 |
| EKPC | EKPC | Related | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | | Unrelated | 325.0 | 0.0 | 0.0 | 0.0 | 189.9 | 514.9 |
| Exelon | AECO | Related | 0.0 | 0.0 | 0.0 | 0.0 | 8.3 | 8.3 |
| | | Unrelated | 48.3 | 57.3 | 0.0 | 0.0 | 1,667.0 | 1,772.6 |
| | BGE | Related | 0.0 | 0.0 | 0.0 | 0.0 | 20.0 | 20.0 |
| | | Unrelated | 0.0 | 1.1 | 0.0 | 0.0 | 33.3 | 34.4 |
| | ComEd | Related | 0.0 | 9.0 | 0.0 | 0.0 | 0.0 | 9.0 |
| | | Unrelated | 1,679.5 | 0.0 | 0.0 | 0.0 | 1,358.8 | 3,038.3 |
| | DPL | Related | 0.0 | 7.4 | 0.0 | 0.0 | 0.0 | 7.4 |
| | | Unrelated | 1,365.0 | 111.0 | 37.0 | 0.0 | 1,516.7 | 3,029.7 |
| | PECO | Related | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | | Unrelated | 18.0 | 3.3 | 0.0 | 0.0 | 51.4 | 72.7 |
| | Pepco | Related | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | | Unrelated | 76.3 | 0.0 | 0.0 | 0.0 | 175.8 | 252.1 |
| First Energy | APS | Related | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | | Unrelated | 507.5 | 53.0 | 10.0 | 313.3 | 1,486.4 | 2,370.2 |
| | ATSI | Related | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | | Unrelated | 940.9 | 0.0 | 0.0 | 0.0 | 216.1 | 1,157.0 |
| | JCPL | Related | 0.0 | 0.0 | 0.0 | 0.0 | 12.0 | 12.0 |
| | | Unrelated | 35.1 | 301.6 | 81.9 | 37.6 | 1,360.6 | 1,816.7 |
| | Met-Ed | Related | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | | Unrelated | 230.0 | 0.0 | 0.0 | 0.0 | 467.0 | 697.0 |
| | PENELEC | Related | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | | Unrelated | 243.9 | 0.0 | 0.0 | 3.0 | 121.7 | 368.6 |
| PPL | PPL | Related | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | | Unrelated | 30.0 | 15.0 | 0.0 | 0.0 | 283.7 | 328.7 |
| PSEG | PSEG | Related | 24.3 | 111.1 | 4.0 | 0.0 | 36.4 | 175.8 |
| | | Unrelated | 25.0 | 82.4 | 26.1 | 6.0 | 416.9 | 556.4 |
| Con Ed | RECO | Related | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | | Unrelated | 40.0 | 0.0 | 0.0 | 0.0 | 0.0 | 40.0 |
| Total | | Related | 467.6 | 436.6 | 4.0 | 10.0 | 386.5 | 1,304.6 |
| | | Unrelated | 24,352.7 | 882.1 | 484.7 | 434.5 | 21,414.4 | 47,568.4 |

## Regional Transmission Expansion Plan (RTEP)[33]

The PJM RTEP process is designed to identify needed transmission system additions and improvements to continue to provide reliable service throughout the RTO. The objective of the RTEP process is to provide PJM with an optimal set of solutions necessary to solve reliability issues, operational performance issues and transmission constraints. Additionally, board approved transmission system enhancements to meet local reliability requirements are also included in the RTEP process.

The RTEP process initially considered only factors such as load growth and the generation interconnection requests in its development of the 15 year plan. Today, the RTEP process includes a broader range of inputs. Some of those inputs include the effects of public policy, market efficiency, interregional coordination and the effects of aging infrastructure.

### RTEP Process

The PJM RTEP process is a 24 month planning process that identifies reliability issues for the next 15 year period. This 24 month planning process includes a process to build power flow models that represent the expected future system topology, studies to identify issues, stakeholder input and PJM Board of Manager approvals. The 24 month planning process is made up of overlapping 18 month planning cycles to identify and develop shorter lead time transmission upgrades and one 24 month planning cycle to provide sufficient time for the identification and development of longer lead time transmission upgrades that may be required to satisfy planning criteria.

### Backbone Facilities

PJM baseline transmission projects are implemented to resolve reliability criteria violations. PJM backbone transmission projects are a subset of significant baseline projects, which are intended to resolve multiple reliability criteria violations and congestion issues and which may have substantial impacts on energy and capacity markets. There are currently three backbone projects under development, Surry Skiffes Creek 500kV, and the conversion of the Marion-Bayonne and Bayway-Linden lines from 138 kV to 345 kV.[34]

### Market Efficiency Process

PJM's Regional Transmission Expansion Plan (RTEP) process includes a market efficiency analysis. The purpose of the market efficiency analysis is: to determine which reliability based enhancements have economic benefit if accelerated; to identify new transmission enhancements that result in economic benefits; and to identify economic benefits associated with modification to existing RTEP reliability based enhancements that when modified would relieve one or more economic constraints. PJM identifies the economic benefit of proposed transmission projects based on production cost analyses.[35] PJM presents the RTEP market efficiency enhancements to the PJM Board, along with stakeholder input, for Board approval.

To be recommended to the PJM Board of Managers for approval, the relative benefits and costs of the economic based enhancement or expansion must meet a benefit/cost ratio threshold of at least 1.25:1. The benefit/cost ratio is the ratio of the present value of the total annual benefit for 15 years to the present value of the total annual cost for the first 15 years of the life of the enhancement or expansion.

The market efficiency process is comprised of a 12 month cycle and a 24 month cycle, both of which begin and end on the calendar year. The 12 month cycle is used for analysis of modifications and accelerations to approved RTEP projects only. The 24 month cycle is used for analysis of new economic transmission projects for years five through 15. This long-term proposal window takes place concurrent with the long-term proposal window for reliability projects.[36]

The first market efficiency cycle conducted under Order 1000 was performed during the 2014/2015 RTEP long term window. Issues were identified on a

33 The material in this section is based in part on the PJM Manual 14B: PJM Region Transmission Planning Process. See PJM, "*PJM Manual 14B: PJM Region Transmission Planning Process,*" Rev. 42 (August 23, 2018) <http://www.pjm.com/-/media/documents/manuals/m14b.ashx?la=en>.

34 See PJM. "*2017 RTEP Process Scope and Input Assumptions White Paper,*" P 25. <http://www.pjm.com/-/media/library/reports-notices/2017-rtep/20170731-rtep-input-assumptions-and-scope-whitepaper.ashx?la=en>.

35 See PJM. "*PJM Regional Transmission Expansion Plan: 2016,*" (February 28, 2017). <http://www.pjm.com/-/media/library/reports-notices/2016-rtep/2016-rtep-books-1-3.ashx?la=en>.

36 See PJM. "*PJM Market Efficiency Modeling Practices,*" (February 2, 2017). <http://www.pjm.com/-/media/planning/rtep-dev/market-efficiency/pjm-market-efficiency-modeling-practices.ashx?la=en>.

total of 77 flowgates, 57 of which were market efficiency drivers. The proposal window was open from October 30, 2014, through February 27, 2015. PJM received 119 proposals, 93 of which addressed the market efficiency issues. A total of 14 projects were approved by the PJM Board for this window, 13 of which were market efficiency projects.

The second market efficiency cycle was performed during the 2016/2017 RTEP long term window. Issues were identified on a total of four flowgates, all four of which were market efficiency drivers, needed to address historical congestion. The proposal window was open from November 1, 2016 through February 28, 2017. PJM received 96 proposals, all 96 of which addressed the market efficiency issues. A total of four projects were approved by the PJM Board for this window, four of which were market efficiency projects.

The third market efficiency cycle is currently being prepared for the 2018/2019 RTEP long term window. The proposal window will be open from November 1, 2018 through February 28, 2019.

During the first nine months of 2018, the PJM Board of Managers received correspondence from several officials, representing regions in Pennsylvania and Maryland, requesting an updated benefit/cost evaluation and the cancellation of the previously approved Transource AP-South market efficiency project.[37] [38] [39] [40] Approved market efficiency projects periodically undergo a reevaluation process to ensure that the benefit/cost ratio continues to meet the 1.25:1 threshold. The Transource AP-South project was reevaluated in September 2017, February 2018 and again in September 2018. The project exceeded the 1.25:1 threshold in all reevaluations. PJM also concluded that there would be significant reliability violations with the project removed from the model.[41]

37 See Letter from Governor Larry Hogan, State of Maryland, Office of the Governor,(July 10, 2018)) <https://www.pjm.com/-/media/about-pjm/who-we-are/public-disclosures/20180828-gov-hogan-rransource-july-2018-letter-to-pjm-board.ashx?la=en>.

38 See Letter from State Representative Kristin Phillips Hill, 93rd District, Pennsylvania House of Representatives (September 6, 2018) <https://www.pjm.com/-/media/about-pjm/who-we-are/public-disclosures/20180906-pa-rep-phillips-hill-letter-re-transource-llc.ashx?la=en>.

39 See Letter from State Representative Stanley E. Saylor, 94th District, Pennsylvania House of Representatives (August 1, 2018) <https://www.pjm.com/-/media/about-pjm/who-we-are/public-disclosures/20180907-pa-rep-saylor-letter-re-transource-llc.ashx?la=en>.

40 See Letter from Paula M. Carmody, People Counsel, State of Maryland Office of People's Counsel (September 6, 2018) <https://www.pjm.com/-/media/about-pjm/who-we-are/public-disclosures/20180907-opc-letter-to-pjm-board-re-sept-2018-transource-retool.ashx?la=en>.

41 See "Transource AP-South (2014/15_9A) Project Reevaluation," <https://www.pjm.com/-/media/committees-groups/committees/teac/20180913/20180913-ap-south-9a-project-reevaluation-sept-2018.ashx>.

## The Benefit/Cost Evaluation

For an RTEP project to be recommended to the PJM Board of Managers for approval as a Market Efficiency project, the relative benefits and costs of the economic based enhancement or expansion must meet a benefit/cost ratio threshold of at least 1.25:1.

The total benefit of a project is calculated as the sum of the present value of calculated Energy Market Benefits and calculated Reliability Pricing Model (RPM) Benefits for the 15 year period. The net present value of the benefits of the project are calculated for 15 years, starting with the projected in service date. Reductions in costs are calculated as a positive benefit. The method for calculating Energy Market Benefits and Reliability Pricing Model Benefits used to measure the benefit of an RTEP project for purposes of the 1.25:1 benefit/cost ratio threshold depends on whether the project is regional or subregional. A regional project is any project rated at or above 230 kV. A subregional project is any project rated at less than 230 kv.

The Energy Market Benefit analysis is generated using an energy market simulation tool that produces an hourly least-cost, security constrained market solution, complete with total operational costs, hourly LMPs, bus specific injections and bus specific withdrawals for each modeled year with and without the proposed RTEP project. Using the output from the model, PJM calculates changes in Energy Production Costs and Load Energy Payments. Changes in Energy Production Costs are calculated on a system wide basis. Using the modeled changes in LMPs, changes in Load Energy Payments are calculated on a zonal basis and are netted against corresponding changes in the value of any Auction Revenue Rights (ARR) that sink in that zone. The value of the ARR rights with and without the RTEP project is evaluated based on changes in CLMPs on the latest, historic allocation of ARR rights. ARR MW allocations are not adjusted to reflect any potential changes in ARR allocations which may be allowed by the RTEP upgrade. To generate the estimate of the Energy Market Benefits, PJM simulates four year (RTEP -4, RTEP, RTEP +3 and RTEP +6) and interpolates between the simulated years and extrapolates after the RTEP +6 simulation.

For a regional project, the Energy Market Benefit for each modeled year is equal to 50 percent of the change in system-wide Total Energy Production Costs with and without the project plus 50 percent of the change in zonal Load Energy Payments with and without the project, including only those zones where the project reduced the Load Energy Payments. For subregional projects, the Energy Market Benefits for each modeled year is equal to the change in zonal Load Energy Payments with and without the project, including only those zones where the project reduced the Load Energy Payments.

The Reliability Pricing Model Benefit analysis is conducted using the Reliability Pricing Model solution software, with and without the proposed RTEP project, using a set of estimated capacity offers. To generate the estimate of the Energy Market Benefits, PJM simulates three years (RTEP, RTEP +3 and RTEP +6) and interpolates between the simulated years and extrapolates after the RTEP +6 simulation.

For a regional project, the Reliability Pricing Model Benefit for each modeled year is equal to 50 percent of the change in system-wide Total System Capacity Cost with and without the project plus 50 percent of the change in zonal Load Capacity Payments with and without the project, including only those zones where the project reduced the Load Capacity Payments. For subregional projects, the Reliability Pricing Model Benefits for each modeled year is equal to the change in zonal Load Capacity Payments with and without the project, including only those zones where the project reduced the Load Capacity Payments.

The difference in the benefits calculation used in the regional and subregional cost benefit threshold tests are related to how costs are allocated for approved regional and subregional projects. The costs of an approved regional project are allocated so that 50 percent of the total costs are allocated on a system wide load ratio share basis and the remaining 50 percent of the total costs are allocated to zones with projected Energy Market Benefits and Reliability Pricing Model Benefits in proportion to those projected positive benefits. The costs of an approved subregional project are allocated so that the total costs of the project is allocated to zones with projected Energy Market benefits and Reliability Pricing Model Benefits in proportion to those projected positive benefits.

The MMU recommends that PJM reevaluate the rules governing cost benefit analysis and cost allocation for economic projects. The current benefit analysis for a regional project, for example, explicitly ignores the negative effects that an RTEP project may have on a subset of zones when calculating the Energy Market Benefits, yet allocates 50 percent of the total cost of a project to the entire system, including that zone hurt by the RTEP project. It is not clear that the evaluation of Energy Production Costs benefits as a fifty percent contributor of benefit justifies allocating fifty percent of the costs on a system-wide basis, as the production cost saving are likely realized within the same zones that receive the Energy Market Benefits. More specific analysis of locational costs and benefits should be included in the overall evaluation.

## PJM MISO Interregional Targeted Market Efficiency Process (TMEP)

PJM and MISO developed a process to facilitate the construction of interregional projects in response to the Commissions concerns about interregional coordination along the PJM-MISO seam, called the Targeted Market Efficiency Process (TMEP).[42]

The allocation of costs to each RTO for TMEPs will be in proportion to the benefits received.[43]

On November 2, 2017, PJM submitted a compliance filing including additional revisions the MISO-PJM JOA to include stakeholder feedback in the TMEP project selection process.[44] [45]

The first TMEP analysis occurred in 2017 and included the investigation of congestion on 50 market to market flowgates. The study resulted in the evaluation of 13 potential upgrades, resulting in the recommendation of five TMEP projects. The five projects address $59 million in historical congestion,

42 See *PJM Interconnection, LLC*, Docket No. ER17-718-000 (December 30, 2016).
43 See *PJM Interconnection, LLC*, Docket No. ER17-729-000 (December 30, 2016).
44 See *PJM Interconnection, LLC*, Docket No. ER17-718-000, ER17-721-000 and ER17-729-000 (Not Consolidated) (November 2, 2017).
45 161 FERC ¶ 61,005.

with a TMEP benefit of $99.6 million. The projects have a total cost of $20 million, with a 5.0 average benefit/cost ratio. PJM and MISO presented the five recommended projects to their boards in December, 2017, and both boards approved all five projects.[46]

The 2018 TMEP analysis included the investigation of congestion on 61 market to market flowgates. The study resulted in the evaluation of 19 potential upgrades, resulting in the recommendation of two TMEP projects. The two projects address $25 million in historical congestion, with a TMEP benefit of $31.9 million. The projects have a total cost of $4.5 million, with a 7.1 average benefit/cost ratio. PJM and MISO will present the two recommended projects to their boards in December 2018.[47]

## Supplemental Transmission Projects

Supplemental projects are "transmission expansions or enhancements that are not required for compliance with PJM criteria and are not state public policy projects according to the PJM Operating Agreement. These projects are used as inputs to RTEP models, but are not required for reliability, economic efficiency or operational performance criteria, as determined by PJM."[48] Supplemental projects are funded wholly by the Transmission Owner and no PJM approval is needed. Supplemental projects addressed two of the four issues identified in the most recent market efficiency cycle. Because supplemental projects are considered by transmission owners to be outside the scope of FERC Order No. 1000, supplemental projects are currently excluded from the Order No. 1000 competitive process.

Figure 12-3 shows the latest cost estimate of all supplemental projects by expected in service year. FERC Order 890 was issued on February 16, 2007, and implemented in PJM starting in 2008. Order 890 required Transmission Providers to participate in a coordinated, open and transparent planning process. Prior to the implementation of Order 890, there were transmission projects planned by transmission owners and included in the PJM planning models, that were not included in the totals shown in Figure 12-3, Table 12-40 and Table 12-41. There has been a significant increase in supplemental projects coincident with the coordinated, open and transparent planning process introduced by the implementation of Order 890 starting in 2008 and the competitive planning process introduced by the implementation of FERC Order No. 1000 starting in 2011.

Figure 12-3 Latest cost estimate of supplemental projects by expected in service year: 1998 through 2018

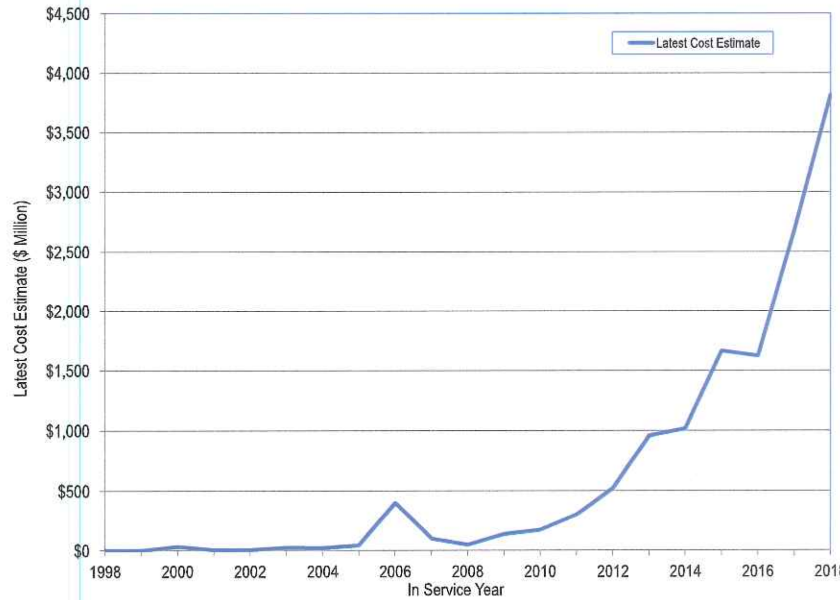



Table 12-40 shows the number of supplemental projects by expected in service year for each transmission zone. The average number of supplemental projects in each expected in service year increased by 500.0 percent, from 20 for years 1998 through 2007 (pre Order 890) to 120 for years 2008 through 2018 (post Order 890).

46 See PJM. "*MISO PJM IPSAC*," (January 12, 2018) <http://www.pjm.com/-/media/committees-groups/stakeholder-meetings/ipsac/20180112/20180112-ipsac-presentation.ashx>.
47 See PJM. "*MISO PJM IPSAC*," (October 5, 2018) <https://www.pjm.com/-/media/committees-groups/stakeholder-meetings/ipsac/20181005/20181005-ipsac-presentation.ashx>.
48 See PJM. "*Transmission Construction Status*," (January 23, 2018) <http://www.pjm.com/planning/rtep-upgrades-status/construct-status.aspx>.

**Table 12-40 Number of supplemental projects by expected in service year and zone: 1998 through 2030**

| Year | AECO | AEP | APS | ATSI | BGE | ComEd | DAY | DEOK | DLCO | Dominion | DPL | EKPC | JCPL | Met-Ed | PECO | PENELEC | Pepco | PPL | PSEG | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1998 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 3 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 3 |
| 1999 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 2 |
| 2000 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 11 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 11 |
| 2001 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 14 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 14 |
| 2002 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 10 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 10 |
| 2003 | 3 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 10 | 0 | 0 | 0 | 0 | 2 | 0 | 0 | 0 | 15 |
| 2004 | 5 | 0 | 10 | 0 | 0 | 9 | 0 | 0 | 0 | 0 | 12 | 0 | 2 | 0 | 0 | 0 | 0 | 0 | 2 | 40 |
| 2005 | 4 | 2 | 8 | 0 | 0 | 4 | 0 | 0 | 0 | 1 | 14 | 0 | 1 | 0 | 1 | 2 | 0 | 0 | 2 | 39 |
| 2006 | 4 | 2 | 5 | 0 | 0 | 6 | 0 | 0 | 0 | 0 | 9 | 0 | 1 | 0 | 0 | 1 | 0 | 1 | 1 | 30 |
| 2007 | 1 | 1 | 5 | 0 | 4 | 5 | 0 | 0 | 4 | 0 | 6 | 0 | 0 | 0 | 0 | 2 | 0 | 1 | 6 | 35 |
| 2008 | 3 | 0 | 15 | 0 | 1 | 6 | 0 | 0 | 1 | 7 | 3 | 0 | 0 | 1 | 0 | 0 | 0 | 3 | 1 | 41 |
| 2009 | 3 | 1 | 5 | 0 | 1 | 8 | 0 | 0 | 3 | 3 | 5 | 0 | 0 | 0 | 5 | 1 | 0 | 0 | 2 | 37 |
| 2010 | 0 | 6 | 7 | 0 | 3 | 4 | 0 | 0 | 6 | 3 | 0 | 0 | 1 | 2 | 2 | 0 | 0 | 2 | 5 | 41 |
| 2011 | 0 | 8 | 8 | 0 | 0 | 2 | 0 | 0 | 5 | 2 | 0 | 0 | 1 | 0 | 4 | 0 | 0 | 3 | 4 | 37 |
| 2012 | 0 | 5 | 6 | 4 | 1 | 2 | 0 | 7 | 3 | 16 | 1 | 0 | 2 | 0 | 1 | 0 | 0 | 4 | 11 | 63 |
| 2013 | 5 | 21 | 4 | 5 | 0 | 11 | 0 | 6 | 5 | 13 | 1 | 0 | 1 | 1 | 1 | 0 | 1 | 13 | 19 | 107 |
| 2014 | 2 | 31 | 2 | 8 | 2 | 14 | 0 | 5 | 6 | 18 | 3 | 2 | 2 | 0 | 1 | 2 | 0 | 8 | 16 | 122 |
| 2015 | 4 | 15 | 2 | 9 | 1 | 37 | 0 | 8 | 4 | 17 | 5 | 4 | 2 | 0 | 1 | 0 | 4 | 7 | 25 | 145 |
| 2016 | 5 | 10 | 4 | 17 | 0 | 26 | 0 | 6 | 2 | 13 | 4 | 2 | 0 | 1 | 3 | 2 | 3 | 11 | 30 | 139 |
| 2017 | 6 | 124 | 7 | 26 | 1 | 23 | 0 | 3 | 8 | 34 | 7 | 5 | 0 | 3 | 0 | 3 | 2 | 22 | 38 | 312 |
| 2018 | 14 | 98 | 5 | 8 | 2 | 12 | 0 | 12 | 6 | 24 | 11 | 6 | 0 | 0 | 2 | 1 | 0 | 29 | 42 | 272 |
| 2019 | 7 | 43 | 0 | 1 | 2 | 5 | 0 | 4 | 1 | 10 | 2 | 7 | 0 | 0 | 1 | 0 | 1 | 40 | 23 | 147 |
| 2020 | 8 | 21 | 1 | 0 | 0 | 1 | 0 | 1 | 0 | 12 | 2 | 3 | 0 | 0 | 0 | 1 | 0 | 20 | 26 | 96 |
| 2021 | 3 | 27 | 0 | 0 | 0 | 1 | 10 | 0 | 2 | 7 | 0 | 2 | 1 | 0 | 0 | 0 | 0 | 23 | 7 | 83 |
| 2022 | 2 | 0 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 0 | 5 | 0 | 1 | 0 | 0 | 0 | 2 | 18 | 0 | 29 |
| 2023 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 0 | 1 | 0 | 0 | 0 | 0 | 8 | 0 | 11 |
| 2024 | 2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 6 | 0 | 8 |
| 2025 | 1 | 0 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 3 | 0 | 5 |
| 2026 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 11 | 0 | 11 |
| 2027 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 |
| 2028 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2029 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2030 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 0 | 1 |
| Total | 83 | 415 | 94 | 78 | 20 | 176 | 10 | 52 | 56 | 181 | 141 | 31 | 16 | 8 | 22 | 17 | 13 | 234 | 260 | 1,907 |

Table 12-41 shows the latest cost estimate of supplemental projects by expected in service year for each transmission zone. The average latest cost of supplemental projects in each expected in service year increased by 1,724.7 percent, from $64.5 million for years 1998 through 2007 (pre Order 890) to $1,176.9 million for years 2008 through 2018 (post Order 890).

Table 12-41 Latest cost estimate by expected in service year and zone ($ millions): 1998 through 2030

| Year | AECO | AEP | APS | ATSI | BGE | ComEd | DAY | DEOK | DLCO | Dominion | DPL | EKPC | JCPL | Met-Ed | PECO | PENELEC | Pepco | PPL | PSEG | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1998 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $1.67 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $1.67 |
| 1999 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.78 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.78 |
| 2000 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $32.95 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $32.95 |
| 2001 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $6.79 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $6.79 |
| 2002 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $7.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $7.00 |
| 2003 | $7.42 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $8.75 | $0.00 | $0.00 | $0.00 | $0.00 | $9.60 | $0.00 | $0.00 | $0.00 | $25.77 |
| 2004 | $4.44 | $0.00 | $9.99 | $0.00 | $0.00 | $0.82 | $0.00 | $0.00 | $0.00 | $0.00 | $7.32 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $22.58 |
| 2005 | $4.06 | $14.67 | $10.11 | $0.00 | $0.00 | $2.58 | $0.00 | $0.00 | $0.00 | $0.02 | $10.97 | $0.00 | $0.00 | $0.00 | $0.50 | $0.00 | $0.00 | $0.00 | $0.00 | $42.90 |
| 2006 | $4.03 | $309.70 | $0.94 | $0.00 | $0.00 | $48.93 | $0.00 | $0.00 | $0.00 | $0.00 | $11.63 | $0.00 | $6.00 | $0.00 | $0.00 | $1.50 | $0.00 | $0.33 | $18.80 | $401.85 |
| 2007 | $0.56 | $2.06 | $9.85 | $0.00 | $37.61 | $4.65 | $0.00 | $0.00 | $31.75 | $0.00 | $9.71 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.34 | $2.25 | $98.77 |
| 2008 | $2.36 | $0.00 | $12.03 | $0.00 | $0.45 | $7.61 | $0.00 | $0.00 | $7.00 | $14.01 | $2.28 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $1.60 | $0.00 | $47.33 |
| 2009 | $0.77 | $0.90 | $12.17 | $0.00 | $5.00 | $21.11 | $0.00 | $0.00 | $19.60 | $2.12 | $7.36 | $0.00 | $0.00 | $0.00 | $48.10 | $2.73 | $0.00 | $0.00 | $17.60 | $137.46 |
| 2010 | $0.00 | $34.36 | $12.13 | $0.00 | $18.90 | $1.38 | $0.00 | $0.00 | $34.45 | $14.98 | $0.00 | $0.00 | $0.03 | $4.58 | $31.80 | $0.00 | $0.00 | $1.08 | $17.72 | $171.41 |
| 2011 | $0.00 | $37.60 | $9.30 | $0.00 | $0.00 | $1.00 | $0.00 | $0.00 | $16.72 | $85.67 | $0.00 | $0.00 | $1.16 | $0.00 | $113.30 | $0.00 | $0.00 | $0.78 | $34.60 | $300.13 |
| 2012 | $0.00 | $46.00 | $5.12 | $0.35 | $2.20 | $12.60 | $0.00 | $26.06 | $11.60 | $165.74 | $0.99 | $0.00 | $6.61 | $0.00 | $12.60 | $0.00 | $0.00 | $8.91 | $223.01 | $521.79 |
| 2013 | $3.15 | $134.93 | $1.10 | $33.68 | $0.00 | $59.25 | $0.00 | $9.93 | $81.98 | $25.03 | $0.99 | $0.00 | $0.05 | $4.10 | $22.50 | $0.00 | $2.40 | $75.84 | $503.72 | $958.65 |
| 2014 | $8.03 | $387.00 | $5.97 | $58.70 | $21.20 | $60.37 | $0.00 | $2.43 | $14.90 | $88.61 | $5.96 | $0.38 | $5.60 | $0.00 | $13.30 | $1.30 | $0.00 | $33.18 | $309.70 | $1,016.63 |
| 2015 | $3.73 | $237.45 | $3.80 | $21.90 | $2.00 | $376.00 | $0.00 | $14.12 | $4.53 | $113.53 | $13.06 | $1.56 | $0.30 | $0.00 | $33.80 | $0.00 | $42.50 | $50.17 | $748.01 | $1,666.46 |
| 2016 | $73.54 | $31.68 | $18.40 | $182.70 | $0.00 | $308.15 | $0.00 | $15.13 | $26.95 | $40.68 | $26.60 | $0.25 | $0.00 | $2.37 | $86.40 | $0.40 | $7.80 | $58.76 | $744.18 | $1,623.99 |
| 2017 | $39.48 | $693.49 | $14.30 | $149.80 | $0.09 | $154.65 | $0.00 | $64.47 | $3.62 | $106.99 | $74.96 | $2.35 | $0.00 | $14.70 | $0.00 | $8.30 | $168.00 | $246.81 | $942.24 | $2,684.25 |
| 2018 | $99.94 | $601.79 | $10.10 | $14.50 | $4.19 | $136.20 | $0.00 | $36.20 | $26.38 | $176.67 | $101.25 | $14.90 | $0.00 | $0.00 | $47.60 | $0.80 | $0.00 | $400.20 | $2,146.14 | $3,816.86 |
| 2019 | $75.98 | $453.28 | $0.00 | $32.00 | $69.20 | $15.80 | $0.00 | $18.84 | $10.60 | $77.60 | $12.45 | $29.54 | $0.00 | $0.00 | $0.80 | $0.00 | $73.50 | $703.31 | $797.00 | $2,369.90 |
| 2020 | $106.17 | $459.86 | $3.60 | $0.00 | $0.00 | $28.00 | $0.00 | $0.66 | $0.00 | $24.63 | $29.30 | $15.46 | $0.00 | $0.00 | $0.00 | $12.80 | $0.00 | $264.82 | $752.20 | $1,697.50 |
| 2021 | $4.63 | $454.75 | $0.00 | $0.00 | $0.00 | $0.00 | $57.10 | $0.00 | $40.00 | $45.15 | $0.00 | $14.70 | $6.90 | $0.00 | $0.00 | $0.00 | $0.00 | $376.68 | $229.00 | $1,228.91 |
| 2022 | $26.80 | $0.00 | $0.00 | $0.00 | $203.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $47.98 | $0.00 | $22.00 | $0.00 | $0.00 | $0.00 | $416.00 | $304.62 | $0.00 | $1,020.40 |
| 2023 | $2.40 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $13.80 | $0.00 | $8.50 | $0.00 | $0.00 | $0.00 | $0.00 | $97.60 | $0.00 | $122.30 |
| 2024 | $2.80 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $199.70 | $0.00 | $202.50 |
| 2025 | $64.00 | $0.00 | $0.00 | $0.00 | $7.50 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $47.00 | $0.00 | $118.50 |
| 2026 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $272.75 | $0.00 | $272.75 |
| 2027 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.70 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.70 |
| 2028 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 |
| 2029 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 |
| 2030 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $2.01 | $0.00 | $2.01 |
| Total | $534.29 | $3,899.52 | $138.91 | $493.63 | $371.34 | $1,239.09 | $57.10 | $187.84 | $330.08 | $982.12 | $434.52 | $79.14 | $57.15 | $25.75 | $410.70 | $37.43 | $710.20 | $3,146.48 | $7,486.17 | $20,621.46 |

The MMU is concerned with the impact of supplemental projects on the market efficiency process. It is not clear how a supplemental project can be used to resolve market efficiency projects that have been identified based on a cost/benefit analysis and why such a project should not be subject to competition. The MMU recommends, to ensure maximum competition, that PJM support ending the exemption of supplemental projects from the Order No. 1000 competitive process.

### End of Life Transmission Projects

An end of life transmission project is a project submitted for the purpose of replacing existing infrastructure that has, or is approaching, the end of its useful life. End of life transmission projects fall under the Transmission Owner Form 715 Planning Criteria, and are currently exempt from the competitive planning process.[49] End of life transmission projects are already included in the supplemental projects totals or, if included in the transmission owners' reliability plan, will be included in the baseline project list as a reliability criteria project.

## Transmission Competition

The MMU makes several recommendations related to the competitive transmission planning process evolves. These recommendations will help ensure that the process is an open and transparent process that results in the most cost effective solutions.

The MMU recommends that PJM enhance the transparency and queue management process for merchant transmission investment. Issues related to data access and complete explanations of cost impacts should be addressed. The goal should be to remove barriers to competition from merchant transmission.

The MMU recommends that PJM continue to incorporate the principle that the goal of transmission planning should be the incorporation of transmission investment decisions into market driven processes as much as possible.

49 See PJM Operating Agreement. Schedule 6 § 1.5.8(o)

The MMU recommends the creation of a mechanism to permit a direct comparison, or competition, between transmission and generation alternatives, including which alternative is less costly and who bears the risks associated with each alternative.

The MMU recommends that PJM establish fair terms of access to rights of way and property, such as at substations, in order to remove any barriers to entry and permit competition between incumbent transmission providers and merchant transmission providers in the RTEP.

### Competitive Planning Process Exclusions

There are several project types that are currently exempt from the competitive planning process. These projects types include:

- **Immediate Need Exclusion:** Due to the immediate need of the violation (3 years or less), the timing required for an RTEP proposal window is considered to be infeasible. As a result, the local Transmission Owner is the Designated Entity.[50]
- **Below 200kV:** Due to the lower voltage level of the identified violation(s), the driver(s) for this project are currently excluded from the competitive proposal window process. As a result, the local Transmission Owner is the Designated Entity.[51]
- **FERC 715 (TO Criteria):** Due to the violation need of this project resulting solely from FERC 715 TO Reliability Criteria, the driver(s) for this project are currently excluded from the competitive proposal window process. As a result, the local Transmission Owner is the Designated Entity.[52]
- **Substation Equipment:** Due to identification of the limiting element(s) as substation equipment, the driver(s) for this project are currently excluded from the competitive proposal window process. As a result, the local Transmission Owner is the Designated Entity.[53]

50 See PJM Operating Agreement. Schedule 6 § 1.5.8(m)
51 See PJM Operating Agreement. Schedule 6 § 1.5.8(n)
52 See PJM Operating Agreement. Schedule 6 § 1.5.8(o)
53 See PJM Operating Agreement. Schedule 6 § 1.5.8(p)

While the PJM Operating Agreement defines who will be the Designated Entity for projects that are excluded from the competitive planning process, neither the PJM Operating Agreement nor the various commission orders on transmission competition prohibit PJM from permitting competition to provide financing for such projects. The MMU recommends that rules be implemented to permit competition to provide financing for transmission projects. This competition could reduce the cost of capital for transmission projects and significantly reduce total costs to customers. In addition, the criteria for and need for all exclusions from the competitive process should be reviewed. There does not appear to be any market reason to exclude transmission projects from competition.

### Cost Capping

The MMU recommended that rules be implemented to require that project cost caps on new transmission projects be part of the evaluation of competing projects. In 2017, PJM formed a special session of the PJM Planning Committee for consideration of cost commitments during the evaluation of competititive transmission proposals. On May 24, 2018, the PJM Markets and Reliability Committee (MRC) approved a motion that required PJM to develop a comparative framework to evaluate the quality and effectiveness of binding cost containment proposals versus proposals without cost containment provisions. The initial motion required the comparative framework to be presented at the December 2018 meeting of the MRC for vote and to be effective for the 2018 long lead project proposal window. At the August 23, 2018, meeting of the MRC, the committee approved a motion to delay the comparative framework deadlines by one year.

## Board Authorized Transmission Upgrades

The Transmission Expansion Advisory Committee (TEAC) regularly reviews internal and external proposals to improve transmission reliability throughout PJM. These proposals are periodically presented to the PJM Board of Managers for authorization.

An RTEP project can be approved by the PJM Board if the project ensures compliance with NERC, regional and local transmission owner planning criteria or to address market efficiency congestion relief. These projects are considered "Baseline Projects". PJM Board approved RTEP projects that are necessary to allow new generation to interconnect reliably are considered "Network Projects". As of December 31, 2017, the PJM Board has approved $35.1 billion in system enhancements. Of that, $27.9 billion (79.5 percent) were baseline projects and $7.2 billion (20.5 percent) were network projects.[54]

In the first nine months of 2018, $1.60 billion in additional projects were approved by the PJM Board:

- On February 13, 2018, the PJM Board of Managers authorized an additional $328.8 million in transmission upgrades and additions.
- On April 10, 2018, the PJM Board of Managers authorized an additional $639.0 million in transmission upgrades and additions.
- On July 31, 2018, the PJM Board of Managers authorized an additional $629.2 million in transmission upgrades and additions.

# Transmission Facility Outages

## Scheduling Transmission Facility Outage Requests

A transmission facility is designated as reportable by PJM if a change in its status can affect a transmission constraint on any Monitored Transmission Facility or could impede free flowing ties within the PJM RTO and/or adjacent areas.[55] When one of the reportable transmission facilities needs to be taken out of service, the TO is required to submit an outage request as early as possible. The specific timeline is shown in Table 12-43.[56]

Transmission outages have significant impacts on PJM markets. There are impacts on FTR auctions, on congestion, and on expected market outcomes in the day-ahead and real-time markets. It is important for the efficient

54 See PJM. "2017 Regional Transmission Expansion Plan – Book 1," P 4. <http://www.pjm.com/-/media/library/reports-notices/2017-rtep/2017-rtep-book-1.ashx?la=en>.

55 If a transmission facility is not modeled in the PJM EMS or the facility is not expected to significantly impact PJM system security or congestion management, it is not reportable. See PJM. "Manual 3A: Energy Management System (EMS) Model Updates and Quality Assurance (QA), Rev. 13 (September 29, 2017).

56 See PJM. "Manual 3: Transmission Operations," Rev. 53 (June 1, 2018), at 65–66.

functioning of the markets that there be clear, enforceable rules governing transmission outages.

Transmission outages are categorized by duration: greater than 30 calendar days; less than or equal to 30 calendar days and greater than five calendar days; or less than or equal to five calendar days.[57] Table 12-42 shows that 70.5 percent of the requested outages were planned for less than or equal to five days and 10.2 percent of requested outages were planned for greater than 30 days in the 2018/2019 planning period. It also shows that 75.9 percent of the requested outages were planned for less than or equal to five days and 7.7 percent of requested outages were planned for greater than 30 days in the 2017/2018 planning period.

All of the outage data in this section in the analysis except for the day-ahead market are for outages scheduled to occur in the planning periods 2017/2018 and 2018/2019, regardless of when they were initially submitted.[58] The outage data in the analysis for the day-ahead market are for outages scheduled to occur from January 1, 2015, through September 30, 2018.

### Table 12-42 Transmission facility outage request summary by planned duration: 2017/2018 and 2018/2019

| | 2017/2018 | | 2018/2019 | |
|---|---|---|---|---|
| Planned Duration (Days) | Outage Requests | Percent of Total | Outage Requests | Percent of Total |
| <=5 | 16,206 | 75.9% | 8,547 | 70.5% |
| >5 & <=30 | 3,489 | 16.3% | 2,340 | 19.3% |
| >30 | 1,650 | 7.7% | 1,236 | 10.2% |
| Total | 21,345 | 100.0% | 12,123 | 100.0% |

After receiving a transmission facility outage request from a TO, PJM assigns a received status to the request based on its submission date and outage planned duration. The received status can be On Time or Late, as defined in Table 12-43.[59]

57 *Id.* at 70.
58 The hotline tickets, EMS tripping tickets or test outage tickets were excluded. The analysis includes only the transmission outage tickets submitted by PJM companies which are currently active.
59 See PJM. "Manual 3: Transmission Operations," Rev. 53 (June 1, 2018) at 65-66.

The purpose of the rules defined in Table 12-43 is to require the TOs to submit transmission facility outages prior to the Financial Transmission Right (FTR) auctions so that market participants have complete information about market conditions on which to base their FTR bids and so that PJM can accurately model market conditions.[60]

### Table 12-43 PJM transmission facility outage request received status definition

| Planned Duration (Calendar Days) | Request Submitted | Received Status |
|---|---|---|
| <=5 | Before the first of the month one month prior to the starting month of the outage | On Time |
| | After or on the first of the month one month prior to the starting month of the outage | Late |
| > 5 & <=30 | Before the first of the month six months prior to the starting month of the outage | On Time |
| | After or on the first of the month six months prior to the starting month of the outage | Late |
| >30 | The earlier of 1) February 1, 2) the first of the month six months prior to the starting month of the outage | On Time |
| | After or on the earlier of 1) February 1, 2) the first of the month six months prior to the starting month of the outage | Late |

Table 12-44 shows a summary of requests by received status. In the 2018/2019 planning period, 37.9 percent of outage requests received were late. In the 2017/2018 planning period, 49.7 percent of outage requests received were late.

### Table 12-44 Transmission facility outage request summary by received status: 2017/2018 and 2018/2019

| | 2017/2018 | | | | 2018/2019 | | | |
|---|---|---|---|---|---|---|---|---|
| Planned Duration (Days) | On Time | Late | Total | Percent Late | On Time | Late | Total | Percent Late |
| <=5 | 8,418 | 7,788 | 16,206 | 48.1% | 5,389 | 3,158 | 8,547 | 36.9% |
| >5 & <=30 | 1,712 | 1,777 | 3,489 | 50.9% | 1,530 | 810 | 2,340 | 34.6% |
| >30 | 609 | 1,041 | 1,650 | 63.1% | 612 | 624 | 1,236 | 50.5% |
| Total | 10,739 | 10,606 | 21,345 | 49.7% | 7,531 | 4,592 | 12,123 | 37.9% |

60 See "Report of PJM Interconnection, LLC. on Transmission Oversight Procedures," Docket No. EL01-122-000 (November 2, 2001).

Once received, PJM processes outage requests in priority order: emergency transmission outage request; transmission outage requests submitted on time; and transmission outage request submitted late. PJM retains the right to deny all transmission outage requests that are submitted late unless the request is an emergency.

Outages with emergency status will be approved even if submitted late after PJM determines that the outage does not result in Emergency Procedures. PJM cancels or withholds approval of any outage that results in Emergency Procedures.[61] Table 12-45 is a summary of outage requests by emergency status. Of all outage requests scheduled to occur in the 2018/2019 planning period, 10.0 percent were for emergency outages. Of all outage requests scheduled to occur in the 2017/2018 planning period, 12.6 percent were for emergency outages.

**Table 12-45 Transmission facility outage request summary by emergency: 2017/2018 and 2018/2019**

| | 2017/2018 | | | | 2018/2019 | | | |
|---|---|---|---|---|---|---|---|---|
| Planned Duration (Days) | Emergency | Non Emergency | Total | Percent Emergency | Emergency | Non Emergency | Total | Percent Emergency |
| <=5 | 2,051 | 14,155 | 16,206 | 12.7% | 860 | 7,687 | 8,547 | 10.1% |
| >5 & <=30 | 399 | 3,090 | 3,489 | 11.4% | 204 | 2,136 | 2,340 | 8.7% |
| >30 | 248 | 1,402 | 1,650 | 15.0% | 149 | 1,087 | 1,236 | 12.1% |
| Total | 2,698 | 18,647 | 21,345 | 12.6% | 1,213 | 10,910 | 12,123 | 10.0% |

PJM will approve all transmission outage requests that are submitted on time and do not jeopardize the reliability of the PJM system. PJM will approve all transmission outage requests that are submitted late and are not expected to cause congestion on the PJM system and do not jeopardize the reliability of the PJM system. Each outage is studied and if it is expected to cause a constraint to exceed a limit, PJM will flag the outage ticket as "congestion expected."[62]

After PJM determines that a late request may cause congestion, PJM informs the Transmission Owner of solutions available to eliminate the congestion. For example, if a generator planned or maintenance outage request is contributing to the congestion, PJM can request that the Generation Owner defer the outage. If no solutions are available, PJM may require the Transmission Owner to reschedule or cancel the outage.

Table 12-46 is a summary of outage requests by congestion status. Of all outage requests submitted to occur in the 2018/2019 planning period, 8.6 percent were expected to cause congestion. Of all the outage requests that were expected to cause congestion, 4.9 percent (51 out of 1,041) were denied by PJM in the 2018/2019 planning period and 18.5 percent (193 out of 1,041) were cancelled (Table 12-48). Of all outage requests submitted to occur in the 2017/2018 planning period, 7.5 percent were expected to cause congestion. Of all the outage requests that were expected to cause congestion, 3.6 percent (58 out of 1,602) were denied by PJM in the 2017/2018 planning period and 19.6 percent (314 out of 1,602) were cancelled (Table 12-48).

**Table 12-46 Transmission facility outage request summary by congestion: 2017/2018 and 2018/2019**

| | 2017/2018 | | | | 2018/2019 | | | |
|---|---|---|---|---|---|---|---|---|
| Planned Duration (Days) | Congestion Expected | No Congestion Expected | Total | Percent Congestion Expected | Congestion Expected | No Congestion Expected | Total | Percent Congestion Expected |
| <=5 | 1,094 | 15,112 | 16,206 | 6.8% | 667 | 7,880 | 8,547 | 7.8% |
| >5 & <=30 | 357 | 3,132 | 3,489 | 10.2% | 241 | 2,099 | 2,340 | 10.3% |
| >30 | 151 | 1,499 | 1,650 | 9.2% | 133 | 1,103 | 1,236 | 10.8% |
| Total | 1,602 | 19,743 | 21,345 | 7.5% | 1,041 | 11,082 | 12,123 | 8.6% |

Table 12-47 shows the outage requests summary by received status, congestion status and emergency status. In the 2018/2019 planning period, 27.9 percent of requests were submitted late and were nonemergency while 1.1 percent of requests (139 out of 12,123) were late, nonemergency, and expected to cause congestion. In the 2017/2018 planning period, 37.1 percent of request were submitted late and were nonemergency while 1.4 percent of requests (297 out of 21,345) were late, nonemergency, and expected to cause congestion.

61 PJM. "Manual 3: Transmission Operations," Rev. 53 (June 1, 2018) at 81.
62 PJM added this definition to Manual 38 in February 2017. PJM. "Manual 38: Operations Planning," Rev. 11 (February 1, 2018) at 20.

Table 12-47 Transmission facility outage request summary by received status, emergency and congestion: 2017/2018 and 2018/2019

| | | 2017/2018 | | | | 2018/2019 | | | |
|---|---|---|---|---|---|---|---|---|---|
| Received Status | | Congestion Expected | No Congestion Expected | Total | Percent of Total | Congestion Expected | No Congestion Expected | Total | Percent of Total |
| Late | Emergency | 85 | 2,592 | 2,677 | 12.5% | 34 | 1,175 | 1,209 | 10.0% |
| | Non Emergency | 297 | 7,632 | 7,929 | 37.1% | 139 | 3,244 | 3,383 | 27.9% |
| On Time | Emergency | 3 | 18 | 21 | 0.1% | 0 | 4 | 4 | 0.0% |
| | Non Emergency | 1,217 | 9,501 | 10,718 | 50.2% | 868 | 6,659 | 7,527 | 62.1% |
| Total | | 1,602 | 19,743 | 21,345 | 100.0% | 1,041 | 11,082 | 12,123 | 100.0% |

Once PJM processes an outage request, the outage request is labelled as Submitted, Received, Denied, Approved, Cancelled by Company, PJM Admin Closure, Revised, Active or Complete according to the processed stage of a request.[63] Table 12-48 shows the detailed process status for outage requests only for the outage requests that are expected to cause congestion. Status Submitted and status Received are in the In Process category and status Cancelled by Company and status PJM Admin Closure are in the Cancelled category in Table 12-48. Table 12-48 shows that of all the outage requests that were expected to cause congestion, 4.9 percent (51 out of 1,041) were denied by PJM in the 2018/2019 planning period, 37.3 percent were complete and 18.5 percent (193 out of 1,041) were cancelled. Of all the outage requests that were expected to cause congestion, 3.6 percent (58 out of 1,602) were denied by PJM in the 2017/2018 planning period, 70.8 percent were complete and 19.6 percent (314 out of 1,602) were cancelled.

Table 12-48 Transmission facility outage requests that might cause congestion status summary: 2017/2018 and 2018/2019

| | | 2017/2018 | | | | | | 2018/2019 | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Received Status | | Cancelled | Complete | In Process | Denied | Congestion Expected | Percent Complete | Cancelled | Complete | In Process | Denied | Congestion Expected | Percent Complete |
| Late | Emergency | 11 | 74 | 0 | 0 | 85 | 87.1% | 4 | 29 | 1 | 0 | 34 | 85.3% |
| | Non Emergency | 47 | 220 | 9 | 18 | 297 | 74.1% | 26 | 71 | 29 | 9 | 139 | 51.1% |
| On Time | Emergency | 2 | 1 | 0 | 0 | 3 | 33.3% | 0 | 0 | 0 | 0 | 0 | 0.0% |
| | Non Emergency | 254 | 839 | 77 | 40 | 1,217 | 68.9% | 163 | 288 | 365 | 42 | 868 | 33.2% |
| Total | | 314 | 1,134 | 86 | 58 | 1,602 | 70.8% | 193 | 388 | 395 | 51 | 1,041 | 37.3% |

There are clear rules defined for assigning On Time or Late status for submitted outage requests in both the PJM Tariff and PJM Manuals.[64] However, the On Time or Late status only affects the priority that PJM assigns for processing the outage request. Table 12-48 shows that in the 2017/2018 planning period, many (74.1 percent or 220 out of 297) outages that were nonemergency, expected to cause congestion, and late transmission outages were approved and completed compared to (51.1 percent or 71 out of 139) outages in the 2018/2019 planning period. The expected impact on congestion is the basis for PJM's treatment of late outage requests. But there is no rule or clear definition of this congestion analysis in the PJM Manuals. The MMU recommends that PJM draft a clear definition of the congestion analysis required for transmission outage requests to include in Manual 3 after appropriate review.

63 See PJM Markets & Operations, PJM Tools "Outage Information," <http://www.pjm.com/markets-and-operations/etools/oasis/system-information/outage-info.aspx> (2017).
64 OA Schedule 1 § 1.9.2.

## Rescheduling Transmission Facility Outage Requests

A TO can reschedule or cancel an outage after initial submission. Table 12-49 is a summary of all the outage requests planned for the planning periods 2017/2018 and 2018/2019 which were approved and then cancelled or rescheduled by TOs at least once. If an outage request was submitted, approved and subsequently rescheduled at least once, the outage request will be counted as Approved and Rescheduled. If an outage request was submitted, approved and subsequently cancelled at least once, the outage request will be counted as Approved and Cancelled. In the 2018/2019 planning period, 21.8 percent of transmission outage requests were approved by PJM and then rescheduled by the TOs, and 8.7 percent of the transmission outages were approved by PJM and subsequently cancelled by the TOs. In the 2017/2018 planning period, 32.2 percent of transmission outage requests were approved by PJM and then rescheduled by the TO, and 12.5 percent of the transmission outages were approved by PJM and subsequently cancelled by the TO.

**Table 12-49 Rescheduled and cancelled transmission outage request summary: 2017/2018 and 2018/2019**

| | 2017/2018 | | | | | 2018/2019 | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Planned Duration (Days) | Outage Requests | Approved and Rescheduled | Percent Approved and Rescheduled | Approved and Cancelled | Percent Approved and Cancelled | Outage Requests | Approved and Rescheduled | Percent Approved and Rescheduled | Approved and Cancelled | Percent Approved and Cancelled |
| <=5 | 16,206 | 3,632 | 22.4% | 2,366 | 14.6% | 8,547 | 1,494 | 17.5% | 948 | 11.1% |
| >5 & <=30 | 3,489 | 2,123 | 60.8% | 229 | 6.6% | 2,340 | 748 | 32.0% | 77 | 3.3% |
| >30 | 1,650 | 1,113 | 67.5% | 65 | 3.9% | 1,236 | 402 | 32.5% | 25 | 2.0% |
| Total | 21,345 | 6,868 | 32.2% | 2,660 | 12.5% | 12,123 | 2,644 | 21.8% | 1,050 | 8.7% |

If a requested outage is determined to be late and TO reschedules the outage, the outage will be revaluated by PJM again as On Time or Late.

A transmission outage ticket with duration of five days or less with an On Time status can retain its On Time status if the outage is rescheduled within the original scheduled month.[65] This rule allows a TO to reschedule within the same month with very little notice.

A transmission outage ticket with a duration exceeding five days with an On Time status can retain its On Time status if the outage is rescheduled to a future month, and the revision is submitted by the first of the month prior to the revised month in which the outage will occur.[66] This rescheduling rule is much less strict than the rule that applies to the first submission of outage requests with similar duration. When first submitted, the outage request with a duration exceeding five days needs to be submitted before the first of the month nine months prior to the month in which the outage was expected to occur.

The MMU recommends that PJM reevaluate all transmission outage tickets as On Time or Late as if they were new requests when an outage is rescheduled and apply the standard rules for late submissions to any such outages.

65 PJM. "Manual 3: Transmission Operations," Rev. 53 June 1, 2018) at 70.
66 *Id.*

## Long Duration Transmission Facility Outage Requests

PJM rules (Table 12-43) define a transmission outage request as On Time or Late based on the planned outage duration and the time of submission. The rule has stricter submission requirements for transmission outage requests planned for longer than 30 days. In order to avoid the stricter submission requirement, some transmission owners divided the duration of outage requests longer than 30 days into shorter segments for the same equipment and submitted one request for each segment. The MMU recommends that PJM not permit transmission owners to divide long duration outages into smaller segments to avoid complying with the requirements for long duration outages.

Table 12-50 shows that there were 8,237 transmission equipment planned outages in the 2018/2019 planning period, of which 1,285 were planned outages longer than 30 days, and of which 189 or 2.3 percent were scheduled longer than 30 days if the duration of the outages were combined for the same equipment. The duration of those outages could potentially be longer than 30 days, however were divided into shorter periods by transmission owners.

Table 12-50 Transmission outage summary: 2017/2018 and 2018/2019

| | | 2017/2018 | | 2018/2019 | |
|---|---|---|---|---|---|
| Planned Duration (Days) | Divided into Shorter Periods | Number of Outages | Percent of Total | Number of Outages | Percent of Total |
| > 30 | No | 1,440 | 11.3% | 1,096 | 13.3% |
| | Yes | 244 | 1.9% | 189 | 2.3% |
| <= 30 | | 11,033 | 86.8% | 6,952 | 84.4% |
| Total | | 12,717 | 100.0% | 8,237 | 100.0% |

Table 12-51 shows the details of potentially long duration (> 30 days) outages when combining the duration of the outages for the same equipment. The actual duration of scheduled outages would be longer than 30 days if the duration of the outages were combined for the same equipment within a period of days. In the 2018/2019 planning period, there would have been 35 outages with a combined duration longer than 30 days that were instead scheduled to occur as shorter outages within a period of more than 31 days and less than 62 days.

Table 12-51 Summary of potentially long duration (> 30 days) outages: 2017/2018 and 2018/2019

| | 2017/2018 | | 2018/2019 | |
|---|---|---|---|---|
| Planned Duration (Days) | Number of Outages | Percent of Total | Number of Outages | Percent of Total |
| <=31 | 6 | 2.5% | 8 | 4.2% |
| >31 & <=62 | 25 | 10.2% | 35 | 18.5% |
| >62 & <=93 | 18 | 7.4% | 10 | 5.3% |
| >93 | 195 | 79.9% | 136 | 72.0% |
| Total | 244 | 100.0% | 189 | 100.0% |

## Transmission Facility Outage Analysis for the FTR Market

Transmission facility outages affect the price and quantity outcomes of FTR Auctions. The purpose of the rules governing outage reporting is to ensure that outages are known with enough lead time prior to FTR Auctions so that market participants can understand market conditions and so that PJM can accurately model market conditions.

There are Long Term, Annual and Monthly Balance of Planning Period auctions in the FTR Market. For each type of auction, PJM includes a set of outages to be modeled.

### Annual FTR Market

The Annual FTR Market includes the Annual ARR Allocation and the Annual FTR Auction. When determining transmission outages to be modeled in the simultaneous feasibility test used in the Annual FTR Market, PJM considers all outages with planned duration longer than or equal to two months and may consider outages with planned durations shorter than two months. PJM may exercise significant discretion in selecting outages to be modeled. PJM posts an FTR outage list to the FTR web page usually at least one week before the auction bidding opening day.[67]

67 PJM Financial Transmission Rights, "Annual ARR Allocation and FTR Auction Transmission Outage Modeling," <http://www.pjm.com/~/media/markets-ops/ftr/annual-ftr-auction/2017-2018/2017-2018-annual-outage-modeling.ashx> (February 21, 2017).

In the 2018/2019 planning period, 241 outage requests were included in the annual FTR market outage list and 11,882 outage requests were not included. In the 2017/2018 planning period, 250 outage requests were included in the annual FTR market outage list and 21,095 outage requests were not included. Table 12-52, Table 12-53, Table 12-54 and Table 12-55 show the summary information on the modeled outage requests and Table 12-56 and Table 12-57 show the summary information on outages that were not included in the Annual FTR Market.

Table 12-52 shows that 6.2 percent of the outage requests modeled in the Annual FTR Market for the 2018/2019 planning period had a planned duration of less than two weeks and that 13.3 percent of the outage requests (32 out of 241) modeled in the Annual FTR Market for the planning period were submitted late according to outage submission rules. It also shows that 3.6 percent of the outage requests modeled in the Annual FTR Market for the 2017/2018 planning period had a planned duration of less than two weeks and that 12.8 percent of the outage requests (32 out of 250) modeled in the Annual FTR Market for the planning period were submitted late according to outage submission rules.

**Table 12-52 Annual FTR market modeled transmission facility outage requests by received status: 2017/2018 and 2018/2019**

| | 2017/2018 | | | | 2018/2019 | | | |
|---|---|---|---|---|---|---|---|---|
| Planned Duration | On Time | Late | Total | Percent of Total | On Time | Late | Total | Percent of Total |
| <2 weeks | 7 | 2 | 9 | 3.6% | 14 | 1 | 15 | 6.2% |
| >=2 weeks & <2 months | 80 | 9 | 89 | 35.6% | 80 | 5 | 85 | 35.3% |
| >=2 months | 131 | 21 | 152 | 60.8% | 115 | 26 | 141 | 58.5% |
| Total | 218 | 32 | 250 | 100.0% | 209 | 32 | 241 | 100.0% |

Table 12-53 shows the annual FTR market modeled outage requests summary by emergency status and received status. Three of the annual FTR market modeled outages expected to occur in the 2018/2019 planning period were emergency outages. None of the modeled outages expected to occur in the 2017/2018 planning period were emergency outages.

**Table 12-53 Annual FTR market modeled transmission facility outage requests by emergency and received status: 2017/2018 and 2018/2019**

| | | 2017/2018 | | | | 2018/2019 | | | |
|---|---|---|---|---|---|---|---|---|---|
| Received Status | Planned Duration | Emergency | Non Emergency | Total | Percent Non Emergency | Emergency | Non Emergency | Total | Percent Non Emergency |
| On Time | <2 weeks | 0 | 7 | 7 | 100.0% | 0 | 14 | 14 | 100.0% |
| | >=2 weeks & <2 months | 0 | 80 | 80 | 100.0% | 0 | 80 | 80 | 100.0% |
| | >=2 months | 0 | 131 | 131 | 100.0% | 0 | 115 | 115 | 100.0% |
| | Total | 0 | 218 | 218 | 100.0% | 0 | 209 | 209 | 100.0% |
| Late | <2 weeks | 0 | 2 | 2 | 100.0% | 0 | 1 | 1 | 100.0% |
| | >=2 weeks & <2 months | 0 | 9 | 9 | 100.0% | 0 | 5 | 5 | 100.0% |
| | >=2 months | 0 | 21 | 21 | 100.0% | 3 | 23 | 26 | 88.5% |
| | Total | 0 | 32 | 32 | 100.0% | 3 | 29 | 32 | 90.6% |

PJM determines expected congestion for both On Time and Late outage requests. A Late outage request may be denied or cancelled if it is expected to cause congestion. Table 12-54 shows a summary of requests by expected congestion and received status. Overall, 6.3 percent (2 out of 32) of all the annual FTR market modeled outages expected to occur in the 2018/2019 planning period and submitted late were expected to cause congestion. Of all the annual FTR market modeled outages expected to occur in the 2017/2018 planning period and submitted late, 12.5 percent (4 out of 32) were expected to cause congestion.

**Table 12-54 Annual FTR market modeled transmission facility outage requests by congestion and received status: 2017/2018 and 2018/2019**

| | | 2017/2018 | | | | 2018/2019 | | | |
|---|---|---|---|---|---|---|---|---|---|
| Received Status | Planned Duration | Congestion Expected | No Congestion Expected | Total | Percent Congestion Expected | Congestion Expected | No Congestion Expected | Total | Percent Congestion Expected |
| On Time | <2 weeks | 3 | 4 | 7 | 42.9% | 5 | 9 | 14 | 35.7% |
| | >=2 weeks & <2 months | 21 | 59 | 80 | 26.3% | 19 | 61 | 80 | 23.8% |
| | >=2 months | 40 | 91 | 131 | 30.5% | 33 | 82 | 115 | 28.7% |
| | Total | 64 | 154 | 218 | 29.4% | 57 | 152 | 209 | 27.3% |
| Late | <2 weeks | 0 | 2 | 2 | 0.0% | 1 | 0 | 1 | 100.0% |
| | >=2 weeks & <2 months | 1 | 8 | 9 | 11.1% | 0 | 5 | 5 | 0.0% |
| | >=2 months | 3 | 18 | 21 | 14.3% | 1 | 25 | 26 | 3.8% |
| | Total | 4 | 28 | 32 | 12.5% | 2 | 30 | 32 | 6.3% |

Table 12-55 shows that 18.8 percent of outage requests modeled in the annual FTR market for the 2018/2019 planning period and with a duration of two weeks or longer but shorter than two months were cancelled, compared to 34.8 percent for the 2017/2018 planning period. Table 12-55 also shows that 16.3 percent of outages requests modeled in the Annual FTR Market for the 2018/2019 planning period and with a duration of two months or longer were cancelled, compared to 12.5 percent for the 2017/2018 planning period.

**Table 12-55 Annual FTR market modeled transmission facility outage requests by processed status: 2017/2018 and 2018/2019**

| | | 2017/2018 | | 2018/2019 | |
|---|---|---|---|---|---|
| Planned Duration | Processed Status | Outage Requests | Percent | Outage Requests | Percent |
| <2 weeks | In Progress | 0 | 0.0% | 11 | 73.3% |
| | Denied | 0 | 0.0% | 0 | 0.0% |
| | Approved | 0 | 0.0% | 0 | 0.0% |
| | Cancelled | 2 | 22.2% | 1 | 6.7% |
| | Revised | 0 | 0.0% | 1 | 6.7% |
| | Active | 0 | 0.0% | 0 | 0.0% |
| | Completed | 7 | 77.8% | 2 | 13.3% |
| | Total | 9 | 100.0% | 15 | 100.0% |
| >=2 weeks & <2 months | In Progress | 7 | 7.9% | 48 | 56.5% |
| | Denied | 2 | 2.2% | 0 | 0.0% |
| | Approved | 0 | 0.0% | 0 | 0.0% |
| | Cancelled | 31 | 34.8% | 16 | 18.8% |
| | Revised | 0 | 0.0% | 0 | 0.0% |
| | Active | 0 | 0.0% | 11 | 12.9% |
| | Completed | 49 | 55.1% | 10 | 11.8% |
| | Total | 89 | 100.0% | 85 | 100.0% |
| >=2 months | In Progress | 29 | 19.1% | 62 | 44.0% |
| | Denied | 0 | 0.0% | 2 | 1.4% |
| | Approved | 2 | 1.3% | 0 | 0.0% |
| | Cancelled | 19 | 12.5% | 23 | 16.3% |
| | Revised | 0 | 0.0% | 0 | 0.0% |
| | Active | 5 | 3.3% | 42 | 29.8% |
| | Completed | 97 | 63.8% | 12 | 8.5% |
| | Total | 152 | 100.0% | 141 | 100.0% |

More outage requests were not modeled in the Annual FTR Market than were modeled in the Annual FTR Market. In the 2018/2019 planning period, 241 outage requests were modeled and 11,882 outage requests were not modeled in the Annual FTR Market. In the 2017/2018 planning period, 250 outage requests were modeled and 21,095 outage requests were not modeled in the Annual FTR Market.

Table 12-56 shows that 3.7 percent of outage requests not modeled in the Annual FTR Auction with duration longer than or equal to two months, labelled On Time according to the rules, were submitted after the Annual FTR Auction bidding opening date for the 2018/2019 planning period compared to 23.0 percent in the 2017/2018 planning period.

Table 12-56 Transmission facility outage requests not modeled in Annual FTR Auction: 2017/2018 and 2018/2019

| | 2017/2018 | | | | | | 2018/2019 | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | On Time | | | Late | | | On Time | | | Late | | |
| Planned Duration | Before Bidding Opening Date | After Bidding Opening Date | Percent After | Before Bidding Opening Date | After Bidding Opening Date | Percent After | Before Bidding Opening Date | After Bidding Opening Date | Percent After | Before Bidding Opening Date | After Bidding Opening Date | Percent After |
| <2 weeks | 1,352 | 8,017 | 85.6% | 282 | 8,548 | 96.8% | 1,926 | 4,191 | 68.5% | 167 | 3,467 | 95.4% |
| >=2 weeks & <2 months | 569 | 409 | 41.8% | 139 | 1,023 | 88.0% | 732 | 259 | 26.1% | 144 | 432 | 75.0% |
| >=2 months | 134 | 40 | 23.0% | 214 | 368 | 63.2% | 206 | 8 | 3.7% | 201 | 149 | 42.6% |
| Total | 2,055 | 8,466 | 80.5% | 635 | 9,939 | 94.0% | 2,864 | 4,458 | 60.9% | 512 | 4,048 | 88.8% |

Table 12-57 shows that 28.9 percent of late outage requests which were not modeled in the Annual FTR Auction with duration longer than or equal to two months and submitted after the Annual FTR Auction bidding opening date were approved and completed in the 2018/2019 planning period. It also shows that 82.9 percent of late outage requests which were not modeled in the Annual FTR Auction with duration longer than or equal to two months and submitted after the Annual FTR Auction bidding opening date were approved and completed in the 2017/2018 planning period.

Table 12-57 Late transmission facility outage requests not modeled in Annual FTR Auction and submitted after annual bidding opening date: 2017/2018 and 2018/2019

| | 2017/2018 | | | 2018/2019 | | |
|---|---|---|---|---|---|---|
| Planned Duration | Completed Outages | Total | Percent Complete | Completed Outages | Total | Percent Complete |
| <2 weeks | 7,111 | 8,548 | 83.2% | 2,558 | 3,467 | 73.8% |
| >=2 weeks & <2 months | 900 | 1,023 | 88.0% | 225 | 432 | 52.1% |
| >=2 months | 305 | 368 | 82.9% | 43 | 149 | 28.9% |
| Total | 8,316 | 9,939 | 83.7% | 2,826 | 4,048 | 69.8% |

Although the definition of late outages was developed in order to prevent outages for the planning period being submitted after the opening of bidding in the Annual FTR Auction, the rules have not functioned effectively because the rule has no direct connection to the date on which bidding opens for the Annual FTR Auction. By requiring all long-duration transmission outages to be submitted before February 1, PJM outage submission rules only prevent long-duration transmission outages from being submitted late. The rule does not address the situation in which long-duration transmission outages are submitted on time, but are rescheduled so that they are late. There is no rule to address the situation in which short-duration outages (duration <= 5 days) are submitted on time, but are changed to long-duration transmission outages after the outages are approved and active. The Annual FTR Auction model may consider transmission outages planned for longer than two weeks but less than two months. Those outages not only include long duration outages but also include outages shorter than 30 days. In those cases, PJM outage submission rules failed to prevent long duration transmission outages from being submitted late. The MMU recommends that PJM modify the rules to eliminate the approval of outage requests submitted or rescheduled after the opening of bidding in the Annual FTR Auction.

## Monthly FTR Market

When determining transmission outages to be modeled in the simultaneous feasibility test used in the Monthly Balance of Planning Period FTR Auction, PJM considers all outages with planned duration longer than five days and may consider outages with planned durations shorter than or equal to five days. PJM may exercise significant discretion in selecting outages to be modeled. PJM posts an FTR outage list to the FTR webpage usually at least one week before the auction bidding opening day.[68] Table 12-58 and Table 12-59 show the summary information on outage requests modeled in the Monthly Balance of Planning Period FTR Auction and Table 12-60 and Table

68 PJM Financial Transmission Rights, "2015/2016 Monthly FTR Auction Transmission Outage Modeling," <http://www.pjm.com/-/media/markets-ops/ftr/ftr-allocation/monthly-ftr-auctions/2015-2016-monthly-transmission-outages-that-may-cause-infeasibilities.ashx?la=en> (December 9, 2015).