BEFORE THE OHIO POWER SITING BOARD

In the Matter of the Ohio Power Siting Board's Report to the General Assembly Regarding the Power Transmission System.	)))))	Case No. 21-796-EL-UNC

COMMENTS OF
THE INDEPENDENT MARKET MONITOR FOR PJM

Monitoring Analytics, LLC, acting in its capacity as the Independent Market Monitor for PJM ("Market Monitor"), submits these comments pursuant to the order issued in this proceeding on July 14, 2021.[1]

The Market Monitor appreciates the opportunity to provide comments to the Ohio Power Siting Board (Board) as part of the Board's development of its report. The Board is required to submit a report to the General Assembly as to whether the current requirements for the planning of the power transmission system and associated facilities investment in Ohio are cost effective and in the interest of consumers. The Board is directed to complete the report in consultation with JobsOhio and to hold at least one public meeting. The report is due to the General Assembly no later than December 1, 2021.

The Market Monitor has, in State of the Market Reports and in testimony and other filings at FERC provided its views and analysis of these issues for all of PJM, including, by definition, Ohio.[2] [3] [4] The Market Monitor's 2021 Quarterly State of the Market Report for

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1 The Federal Energy Regulatory Commission (FERC) has approved PJM Interconnection, L.L.C. ("PJM") as an independent system operator and regional transmission organization. Capitalized terms used herein and not otherwise defined have the meaning used in the FERC-approved PJM Open Access Transmission Tariff ("OATT") or the PJM Operating Agreement ("OA").

2 See the 2020 State of the Market Report for PJM (March 11, 2021); 2021 Quarterly State of the Market Report for PJM: January through March (May 13, 2021). Monitoring Analytics State of the

PJM: January through June, Section 12, includes the Market Monitor's current positions on these issues and cites to additional Market Monitor filings (Attachment A to this filing).

In summary, the Market Monitor believes that it is essential to consider the complete set of issues associated with siting, from competition among transmission providers to competition between transmission and generation resources to meet customer needs, to the impact on all actual congestion payments by customers and the associated efficacy of the FTR/ARR design in returning congestion payments to customers, to the details of line ratings that significantly affect the level of required transmission, to the allocation of costs.[5] [6] There are ongoing developments in the PJM stakeholder process and at FERC related to management of generation queues and the associated impact on transmission requirements.[7] [8] 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

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Market Reports for PJM are found on the Monitoring Analytics, LLC webpage at: <http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2021.shtml>.

3 *Managing Transmission Line Ratings*, FERC Technical Conference, Docket No. AD19-15, (Wednesday, September 11, 2019).

4 Monitoring Analytics, LLC, *Grid Enhancing Technologies,* Docket No. AD19-19 (November 6, 2019). <http://www.monitoringanalytics.com/Filings/2019/IMM_Comments_Docket_No_AD19-19_20191106.pdf>.

5 *PJM Transmission Owners,* Docket No. ER21-2282, Protest of the Independent Market Monitor for PJM, Docket No. ER21-2282, (July 28, 2021).

6 176 FERC ¶ 61,024, *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection,* (July 15, 2021).

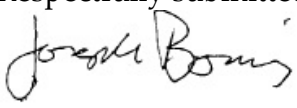
7 163 FERC ¶ 61,043 re *Reform of Generator Interconnection Procedures and Agreements.*

8 PJM. Interconnection Process Reform Task Force (IPRTF) <https://www.pjm.com/committees-and-groups/task-forces/iprtf>.

transmission owners should perform interconnection studies, whether transmission owners should be allowed to require developers to rely on transmission owners for funding, 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. But the behavior of project developers also creates issues with queue management. When developers put multiple projects in the queue to maintain their own optionality while planning to build only one they also affect all the projects that follow them in the queue. Project developers may also enter speculative projects in the queue and then put the project in suspended status while they address financing. The incentives for such behavior should also be addressed, including appropriate nonrefundable fees, appropriate credit requirements, appropriate limits on the use of the suspended option and appropriate milestone requirements.

Thank you for the opportunity to submit comments. The Market Monitor is available to answer questions and submit additional comments as needed.

Respectfully submitted,



Joseph E. Bowring

Independent Market Monitor for PJM
President
Monitoring Analytics, LLC
2621 Van Buren Avenue, Suite 160
Eagleville, Pennsylvania 19403
(610) 271-8053
joseph.bowring@monitoringanalytics.com

DATED: AUGUST 4, 2021

CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing Comments of the Independent Market Monitor for PJM were served upon the following parties of record this 4th day of August, 2021, via electronic transmission.

/s/ *Joseph E. Bowring*
Joseph E. Bowring

Staff, Docketing
Public Utilities Commission of Ohio
180 East Broad Street
Columbus, OH 43215
Email: docketing@puco.ohio.gov

JobsOhio
41 S High Street #1500
Columbus, OH 43215
Email: contact@jobsohio.com

Nicholas Walstra
Public Utilities Commission of Ohio
180 East Broad Street
Columbus, OH 43215
Phone: (614)466-0659
Email: nicholas.walstra@puco.ohio.gov

Evelyn R. Robinson
2750 Monroe Blvd.
Audubon, PA 19403
Phone: 610-639-0491
Email: evelyn.robinson@pjm.com

Heather Chilcote
Public Utilities Commission of Ohio
180 East Broad Street
Columbus, OH 43215
Phone: (614) 466-0407
Email: heather.chilcote@puco.ohio.gov

American Municipal Power, Inc. &
Ohio Municipal Electric Association
Lisa G. McAlister
Senior VP and General Counsel for Regulatory Affairs
1111 Schrock Road, Suite 100
Columbus, Ohio 43229
Telephone: 614-540-6400
Fax: 614-540-6397
Email: lmcalister@amppartners.org

Attachment A

Generation and Transmission Planning[1]

Overview

Generation Interconnection Planning

Existing Generation Mix

- As of March 31, 2021, PJM had a total installed capacity of 197,274.9 MW, of which 49,877.4 MW (25.3 percent) are coal fired steam units, 50,194.0 MW (25.4 percent) are combined cycle units and 33,452.6 MW (17.0 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.
- Of the 197,274.9 MW of installed capacity, 71,985.4 MW (36.5 percent) are from units older than 40 years, of which 38,446.4 MW (53.4 percent) are coal fired steam units, 191.0 MW (0.3 percent) are combined cycle units and 16,184.6 MW (22.5 percent) are nuclear units.

Generation Retirements[2]

- There are 45,070.3 MW of generation that have been, or are planned to be, retired between 2011 and 2024, of which 32,084.1 MW (71.2 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 natural gas.
- In the first three months of 2021, 430.4 MW of generation retired. The largest generator that retired in the first three months of 2021 was the 237.9 MW Birchwood coal fired steam unit located in the Dominion Zone. Of the 430.4 MW of generation that retired, 353.4 MW (82.1 percent) were located in the Dominion Zone.
- As of March 31, 2021, there are 4,622.5 MW of generation that have requested retirement after March 31, 2021, of which 1,786.5 MW (38.7 percent) are located in the COMED Zone. Of the generation requesting retirement in the COMED Zone, all 1,786.5 MW (100.0 percent) are nuclear units.

Generation Queue[3]

- There were 173,182.4 MW in generation queues, in the status of active, under construction or suspended, at the end of 2020. In the first three months of 2021, the AG2 queue window closed. As projects move through the queue process, projects can be removed from the queue due to incomplete or invalid data, withdrawn by the market participant or placed in service. On March 31, 2021, there were 177,645.3 MW in generation queues, in the status of active, under construction or suspended, an increase of 4,462.9 MW (2.6 percent) from the end of 2020.[4]
- As of March 31, 2021, 5,982 projects, representing 668,740.7 MW, have entered the queue process since its inception in 1998. Of those, 967 projects, representing 73,369.0 MW, went into service. Of the projects that entered the queue process, 3,088 projects, representing 417,726.4 MW (62.5 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.
- As of March 31, 2021, 177,645.3 MW were in generation request queues in the status of active, under construction or suspended. Based on historical completion rates, 37,491.5 MW of new generation in the queue are expected to go into service.
- The number of queue entries has increased during the past several years, primarily renewable projects. Of the 3,330 projects entered from January 2015 through March 2021, 2,515 projects (75.5 percent) were renewable. Of the 140 projects entered in the first three months of 2021, 117 projects (83.6 percent) were renewable. Renewable projects make up 79.1 percent of all projects in the queue and those projects account for 76.0 percent of

1 Totals presented in this section include corrections to historical data and may not match totals presented in previous reports.
2 See PJM. Planning. "Generator Deactivations," (Accessed on March 31, 2021) <http://www.pjm.com/planning/services-requests/gen-deactivations.aspx>.
3 See PJM. Planning. "New Services Queue," (Accessed on March 31, 2021) <https://www.pjm.com/planning/services-requests/interconnection-queues.aspx>.
4 The queue totals in this report are the winter net MW energy for the interconnection requests ("MW Energy") as shown in the queue.

the nameplate MW currently active, suspended or under construction in the queue as of March 31, 2021.

But of the 134,968.2 MW of renewable projects in the queue, only 7,506.5 MW (5.6 percent) of capacity resources are expected to go into service, based on both historical completion rates and average derate factors for wind and solar.

Regional Transmission Expansion Plan (RTEP)

Market Efficiency Process

- There are significant issues with PJM's benefit/cost analysis that should be addressed prior to approval of additional projects. PJM's benefit/cost analysis does not correctly account for the costs of increased congestion associated with market efficiency projects.
- Through March 31, 2021, PJM has completed four market efficiency cycles under Order No. 1000.[5]

PJM MISO Interregional Market Efficiency Process (IMEP)

- PJM and MISO developed a process to facilitate the construction of interregional projects in response to the Commission's concerns about interregional coordination along the PJM-MISO seam. This process, called the Interregional Market Efficiency Process (IMEP), operates on a two year study schedule and is designed to address forward looking congestion.

  But the use of an inaccurate cost-benefit method by PJM and the correct method by MISO results in an over allocation of the costs associated with joint PJM/MISO projects to PJM participants and in some cases approval of projects that do not pass an accurate cost-benefit test.

PJM MISO Targeted Market Efficiency Process (TMEP)

- PJM and MISO developed the Targeted Market Efficiency Process (TMEP) to facilitate the resolution of historic congestion issues that could be addressed through small, quick implementation projects.

Supplemental Transmission Projects

- Supplemental projects are defined to be "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."[6] Supplemental projects are exempt from the competitive planning process.
- The average number of supplemental projects in each expected in service year increased by 795.0 percent, from 20 for years 1998 through 2007 (pre Order No. 890[7]) to 179 for years 2008 through 2021 (post Order 890).
- The process for designating projects as supplemental projects should be reviewed and modified to ensure that the supplemental project designation is not used to exempt transmission projects from a transparent, robust and clearly defined mechanism to permit competition to build the project, or used to effectively replace the RTEP process.[8]

End of Life Transmission Projects

- An end of life transmission project is a project submitted for the purpose of replacing existing infrastructure that is at, or is approaching, the end of its useful life. End of life transmission projects should be included in the RTEP process and should be subject to a transparent, robust and clearly

5 See *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, FERC Stats. & Regs. ¶ 31,323 (2011) (Order No. 1000), *order on reh'g*, Order No. 1000-A, 139 FERC ¶ 61,132 (2012).

6 See PJM. "Transmission Construction Status," (Accessed on March 31, 2021) <http://www.pjm.com/planning/rtep-upgrades-status/construct-status.aspx>.

7 *See Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 118 FERC ¶ 61,119, *order on reh'g*, Order No. 890-A, 121 FERC ¶ 61,297 (2007), *order on reh'g*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh'g*, Order No. 890-C, 126 FERC ¶ 61,228, *order on clarification*, Order No. 890-D, 129 FERC ¶ 61,126 (2009).

8 FERC accepted tariff provisions that exclude supplemental projects from competition in the RTEP. 162 FERC ¶ 61,129 (2018), *reh'g denied*, 164 FERC ¶ 61,217 (2018).

defined mechanism to permit competition to build the project. Under the current approach, end of life projects are excluded from competition.[9]

Board Authorized Transmission Upgrades

- The Transmission Expansion Advisory Committee (TEAC) reviews internal and external proposals to improve transmission reliability throughout PJM. These proposals, which include reliability baseline, network, market efficiency and targeted market efficiency projects, as well as scope changes and project cancellations, but exclude supplemental and end of life projects, are periodically presented to the PJM Board of Managers for authorization.[10] In the first three months of 2021, the PJM Board approved $349.8 million in upgrades. As of March 31, 2021, the PJM Board has approved $38.2 billion in system enhancements since 1999.

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 nonincumbent transmission. These recommendations would help ensure that the process is an open and transparent process that results in the most competitive solutions.
- On May 24, 2018, the PJM Markets and Reliability Committee (MRC) approved a motion that required PJM, with input from the MMU, to develop a comparative framework to evaluate the quality and effectiveness of competitive transmission proposals with binding cost containment proposals compared to proposals from incumbent and nonincumbent transmission companies without cost containment provisions.

Qualifying Transmission Upgrades (QTU)

- A Qualifying Transmission Upgrade (QTU) is an upgrade to the transmission system that increases the Capacity Emergency Transfer Limit (CETL) into an LDA and can be offered into capacity auctions as capacity. Once a QTU is in service, the upgrade is eligible to continue to offer the approved incremental import capability into future RPM Auctions. As of March 31, 2021, no QTUs have cleared a Base Residual Auction or an Incremental Auction.

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.[11]
- There were 16,542 transmission outage requests submitted in the first ten months of the 2020/2021 planning period. Of the requested outages, 77.2 percent of the requested outages were planned for less than or equal to five days and 8.4 percent of requested outages were planned for greater than 30 days. Of the requested outages, 42.7 percent were late according to the rules in PJM's Manual 3.

Recommendations

Generation Retirements

- The MMU recommends that the question of whether Capacity Interconnection Rights (CIRs) should persist after the retirement of a unit be addressed. The rules need to ensure that incumbents cannot exploit control of CIRs to block or postpone entry of competitors.[12] (Priority: Low. First reported 2013. Status: Partially adopted, 2012.)

9 In recent decisions addressing competing proposals on end of life projects, the Commission accepted a transmission owner proposal excluding end of life projects from competition in the RTEP process, 172 FERC ¶ 61,136 (2020), *reh'g denied*, 173 FERC ¶ 61,225 (2020), and rejected a proposal from PJM stakeholders that would have included end of life projects in competition in the RTEP process, 173 FERC ¶ 61,242 (2020).

10 Supplemental Projects, including the end of life subset of supplemental projects, do not require PJM Board of Managers authorization.

11 See PJM. "PJM Manual 03: Transmission Operations," Rev. 58 (November 19, 2020).

12 See "Comments of the Independent Market Monitor for PJM," Docket No. ER12-1177-000 (March 12, 2012) <http://www.monitoringanalytics.com/Filings/2012/IMM_Comments_ER12-1177-000_20120312.PDF>.

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.)
- 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 the market efficiency process be eliminated because it is not consistent with a competitive market design. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that, if the market efficiency process is retained, PJM modify the rules governing benefit/cost analysis, the evaluation process for selecting among competing market efficiency projects and cost allocation for economic projects in order to ensure that all costs, including increased congestion costs and the risk of project cost increases, in all zones are included in order to ensure that the correct metrics are used for defining benefits. (Priority: Medium. First reported 2018. Status: Not adopted.)

Comparative Cost Framework

- The MMU recommends that PJM modify the project proposal templates to include data necessary to perform a detailed project lifetime financial analysis. The required data includes, but is not limited to: capital expenditure; capital structure; return on equity; cost of debt; tax assumptions; ongoing capital expenditures; ongoing maintenance; and expected life. (Priority: Medium. First reported 2020. Status: Not adopted.)

Transmission Competition

- The MMU recommends, to increase the role of competition, that the exemption of supplemental projects from the Order No. 1000 competitive process be terminated and that the basis for all such exemptions be reviewed and modified to ensure that the supplemental project designation is not used to exempt transmission projects from a transparent, robust and clearly defined mechanism to permit competition to build such projects or to effectively replace the RTEP process. (Priority: Medium. First reported 2017. Status: Not adopted. Rejected by FERC.)
- The MMU recommends, to increase the role of competition, that the exemption of end of life projects from the Order No. 1000 competitive process be terminated and that end of life transmission projects be included in the RTEP process and should be subject to a transparent, robust and clearly defined mechanism to permit competition to build such projects. (Priority: Medium. First reported 2019. Status: Not adopted. Rejected by FERC.)

- The MMU recommends that PJM enhance the transparency and queue management process for nonincumbent 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 nonincumbent transmission providers. (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 nonincumbent 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: Medium. First reported 2015. Status: Adopted 2020.)
- The MMU recommends that storage resources not be includable as transmission assets for any reason. (Priority: High. First reported 2020. Status: Not adopted.)

Cost Allocation

- The MMU recommends a comprehensive review of the ways in which the solution based dfax is implemented. The goal for such a process would be to ensure that the most rational and efficient approach to implementing the solution based dfax method is used in PJM. Such an approach should allocate costs consistent with benefits and appropriately calibrate the incentives for investment in new transmission capability. No replacement approach should be approved until all potential alternatives, including the status quo, are thoroughly reviewed. (Priority: Medium. First reported 2020. Status: Not adopted.)
- 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.[13] (Priority: Medium. First reported 2015. Status: Not adopted.)

Transmission Line Ratings

- The MMU recommends that all PJM transmission owners use the same methods to define line ratings, subject to NERC standards and guidelines, subject to review by NERC and approval by FERC. (Priority: Medium. First reported 2019. Status: Not adopted.)

Transmission Facility Outages

- 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.)

13 See the *2015 State of the Market Report for PJM*, Volume II, Section 12: Generation and Transmission Planning, at p. 463, Cost Allocation Issues.

- 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 MMU recognizes that the Commission has recently issued orders that are inconsistent with the recommendations of the MMU and that PJM cannot unilaterally modify those directives. It remains the recommendation of the MMU that 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 nonincumbent transmission providers. The ability of transmission owners to block competition for supplemental projects and end of life projects and reasons for that policy should be reevaluated. PJM should enhance the transparency and queue management process for nonincumbent 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 nonincumbent 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, paid for by customers. 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.

The process for determining the reasonableness or purpose of supplemental transmission projects that are asserted to be not needed for reliability, economic efficiency or operational performance as defined under the RTEP process needs additional oversight and transparency. If there is a need for a supplemental project, that need should be clearly defined and there should be a transparent, robust and clearly defined mechanism to permit competition to build the project. If there is no defined need for of a supplemental project for reliability, economic efficiency or operational performance then the project should not be included in rates.

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 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.

The current market efficiency process does exactly the opposite by permitting transmission projects to be approved without competition from generation. The broader issue is that the market efficiency project approach explicitly allows transmission projects to compete against future generation projects, but without allowing the generation projects to compete. Projecting speculative transmission related benefits for 15 years based on the existing generation fleet and existing patterns of congestion eliminates the potential for new generation to respond to market signals. The market efficiency process allows assets built under the cost of service regulatory paradigm to displace generation assets built under the competitive market paradigm. In addition, there are significant issues with PJM's current benefit/cost analysis which cause it to consistently overstate the potential benefits of market efficiency projects. The MMU recommends that the market efficiency process be eliminated.

In addition, the use of an inaccurate cost-benefit method by PJM and the correct method by MISO results in an over allocation of the costs associated with joint PJM/MISO projects to PJM participants and in some cases approval of projects that do not pass an accurate cost-benefit test.

If it is retained, there are significant issues with PJM's benefit/cost analysis that should be addressed prior to approval of additional projects. The current benefit/cost analysis for a regional project, for example, explicitly and incorrectly ignores the increased congestion in zones that results from an RTEP project when calculating the energy market benefits. All costs should be included in all zones and LDAs. The definition of benefits should also be reevaluated.

The benefit/cost analysis should also account for the fact that the transmission project costs are not subject to cost caps and may exceed the estimated costs by a wide margin. When actual costs exceed estimated costs, the cost benefit analysis is effectively meaningless and low estimated costs may result in inappropriately favoring transmission projects over market generation projects. The risk of cost increases for transmission projects should be incorporated in the cost benefit analysis.

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.[14] As of March 31, 2021, PJM had an installed capacity of 197,274.9 MW, of which 49,877.4 MW (25.3 percent) are coal fired steam units, 50,194.0 MW (25.4 percent) are combined cycle units and 33,452.6 MW (17.0 percent) are nuclear units. This measure of installed capacity differs from capacity market installed capacity because it includes energy only units, external units and uses nameplate values for solar and wind resources.

The AEP Zone has the most installed capacity of any PJM zone. Of the 197,274.9 MW of PJM installed capacity, 31,720.1 MW (16.1 percent) are in the AEP Zone, of which 13,463.0 MW (42.4 percent) are coal fired steam units, 6,990.0 MW (22.0 percent) are combined cycle units and 2,071.0 MW (6.5 percent) are nuclear units.

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

Table 12-1 Existing capacity: March 31, 2021 (By zone and unit type (MW))[15]

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	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
ACEC	0.0	901.9	544.7	26.0	0.0	1.6	0.0	0.0	0.0	0.0	4.0	8.9	64.1	0.0	0.0	458.9	0.0	0.0	0.0	7.5	0.0	2,017.5
AEP	6.0	6,990.0	4,108.2	16.2	4.8	0.0	66.0	420.9	2,071.0	0.0	0.0	20.4	264.7	0.0	0.0	13,463.0	738.0	0.0	50.0	3,500.9	0.0	31,720.1
APS	80.4	2,179.0	1,223.3	0.0	2.0	0.0	0.0	129.2	0.0	29.6	0.0	18.3	114.4	0.0	0.0	5,299.0	0.0	0.0	0.0	875.1	0.0	9,950.3
ATSI	0.0	3,495.5	958.0	629.0	6.4	0.0	0.0	0.0	2,134.0	0.0	18.5	46.1	0.0	0.0	0.0	2,264.0	325.0	0.0	0.0	0.0	0.0	9,876.5
BGE	0.0	0.0	267.6	228.8	0.0	0.0	0.0	0.4	1,716.0	0.0	0.0	4.2	1.1	0.0	0.0	1,578.0	143.5	397.0	57.0	0.0	0.0	4,393.6
COMED	148.5	2,621.1	6,673.3	226.2	0.0	0.0	0.0	0.0	10,473.5	0.0	0.0	30.3	9.0	0.0	0.0	3,840.1	1,326.0	0.0	0.0	4,831.0	0.0	30,179.0
DAY	0.0	0.0	897.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	34.0	0.0	1.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	932.6
DUKE	18.0	522.2	598.0	56.0	0.0	0.0	0.0	112.0	0.0	0.0	0.0	4.8	200.0	0.0	0.0	1,857.0	47.0	0.0	0.0	0.0	0.0	3,415.0
DUQ	0.0	101.0	0.0	15.0	0.0	0.0	0.0	6.3	1,777.0	0.0	0.0	0.0	0.0	0.0	0.0	565.0	0.0	0.0	0.0	0.0	0.0	2,464.3
DOM	0.0	9,138.0	3,835.3	256.4	10.0	0.0	3,003.0	586.3	3,581.3	0.0	39.0	106.4	2,382.2	0.0	0.0	3,499.2	35.0	800.0	368.4	587.0	0.0	28,227.5
DPL	0.0	1,742.5	978.2	478.2	0.0	30.0	0.0	0.0	0.0	0.0	88.0	14.1	300.4	0.0	0.0	410.0	812.0	153.0	70.0	0.0	0.0	5,076.4
EKPC	0.0	0.0	774.0	0.0	0.0	0.0	0.0	136.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,687.0	0.0	0.0	0.0	0.0	0.0	2,597.0
JCPLC	40.0	2,229.5	531.1	225.6	0.0	0.4	400.0	0.0	0.0	0.0	0.0	14.1	371.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3,812.5
MEC	0.0	2,646.0	2.0	398.5	0.0	0.0	0.0	19.0	0.0	0.0	0.0	33.4	0.0	0.0	0.0	115.0	0.0	0.0	60.0	0.0	0.0	3,273.9
OVEC	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	2,388.8	0.0	0.0	0.0	0.0	0.0	2,388.8
PECO	0.0	4,089.0	0.0	828.0	0.0	0.0	1,070.0	572.0	4,546.8	0.0	2.0	0.9	3.0	0.0	0.0	0.0	762.0	0.0	103.0	0.0	0.0	11,976.7
PE	28.4	1,900.0	350.5	57.0	0.0	0.0	513.0	77.8	0.0	120.1	28.0	17.8	13.5	0.0	0.0	6,053.5	610.0	0.0	42.0	1,100.4	0.0	10,912.0
PEPCO	0.0	1,736.5	764.2	308.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	11.1	2.5	0.0	0.0	1,896.0	1,164.1	0.0	52.0	0.0	0.0	5,934.4
PPL	20.0	5,558.5	252.0	213.5	20.6	0.0	0.0	706.6	2,520.0	12.0	5.0	14.7	35.0	0.0	0.0	2,547.9	2,449.0	0.0	29.0	216.5	0.0	14,600.3
PSEG	7.7	4,343.3	1,039.2	0.0	0.0	0.0	0.0	5.0	3,493.0	0.0	0.0	9.0	224.6	0.0	0.0	0.0	3.0	0.0	179.1	0.0	0.0	9,303.8
XIC	0.0	0.0	858.6	0.0	0.0	0.0	0.0	269.1	1,140.0	0.0	0.0	0.0	0.0	0.0	0.0	1,955.0	0.0	0.0	0.0	0.0	0.0	4,222.7
Total	349.0	50,194.0	24,655.7	3,962.4	43.8	32.0	5,052.0	3,040.6	33,452.6	161.7	218.5	354.4	3,987.3	0.0	0.0	49,877.4	8,414.6	1,350.0	1,010.5	11,118.4	0.0	197,274.9

15 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.

Table 12-2 shows the installed capacity by state for each fuel type. Pennsylvania has the most installed capacity of any PJM state. Of the 197,274.9 MW of installed capacity, 48,057.9 MW (24.4 percent) are in Pennsylvania, of which 9,281.4 MW (19.3 percent) are coal fired steam units, 17,473.5 MW (36.4 percent) are combined cycle units and 8,843.8 MW (18.4 percent) are nuclear units.

Table 12-2 Existing capacity: March 31, 2021 (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	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
DC	0.0	19.5	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	19.5
DE	0.0	742.5	325.5	116.3	0.0	30.0	0.0	0.0	0.0	0.0	0.0	8.1	0.0	0.0	0.0	410.0	812.0	0.0	70.0	0.0	0.0	2,514.4
IL	148.5	2,621.1	6,673.3	226.2	0.0	0.0	0.0	0.0	10,473.5	0.0	0.0	30.3	9.0	0.0	0.0	3,840.1	1,326.0	0.0	0.0	4,831.0	0.0	30,179.0
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	30.1	0.0	0.0	3,923.8	0.0	0.0	0.0	2,353.2	0.0	8,594.9
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	0.0	0.0	1,687.0	278.0	0.0	0.0	0.0	0.0	3,719.1
MD	20.0	2,717.0	1,684.5	552.7	0.0	0.0	0.0	0.4	1,716.0	0.0	76.0	21.3	313.4	0.0	0.0	3,654.0	1,307.6	550.0	109.0	295.0	0.0	13,016.9
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	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	921.5	0.0	0.0	0.0	0.0	0.0	0.0	208.0	0.0	1,627.5
NJ	47.7	7,474.7	2,115.0	251.6	0.0	2.0	400.0	5.0	3,493.0	0.0	4.0	32.0	660.4	0.0	0.0	458.9	3.0	0.0	179.1	7.5	0.0	15,133.8
OH	22.0	6,972.7	4,201.2	701.2	6.4	0.0	0.0	200.0	2,134.0	0.0	47.0	50.9	351.1	0.0	0.0	9,689.0	47.0	0.0	0.0	1,147.7	0.0	25,570.2
PA	49.9	17,473.5	1,491.9	1,512.0	20.6	0.0	1,583.0	1,445.7	8,843.8	161.7	40.5	85.1	106.5	0.0	0.0	9,281.4	4,146.0	0.0	234.0	1,582.3	0.0	48,057.9
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	0.0	0.0	50.0	0.0	0.0	50.0
VA	0.0	8,973.0	4,172.3	591.4	12.0	0.0	3,069.0	460.1	3,581.3	0.0	33.0	112.4	1,570.7	0.0	0.0	2,494.2	495.0	800.0	368.4	12.0	0.0	26,744.8
WV	60.9	0.0	1,073.9	11.0	0.0	0.0	0.0	189.3	0.0	0.0	0.0	8.0	20.0	0.0	0.0	12,484.0	0.0	0.0	0.0	681.7	0.0	14,528.8
XIC	0.0	0.0	858.6	0.0	0.0	0.0	0.0	269.1	1,140.0	0.0	0.0	0.0	0.0	0.0	0.0	1,955.0	0.0	0.0	0.0	0.0	0.0	4,222.7
Total	349.0	50,194.0	24,655.7	3,962.4	43.8	32.0	5,052.0	3,040.6	33,452.6	161.7	218.5	354.4	3,987.3	0.0	0.0	49,877.4	8,414.6	1,350.0	1,010.5	11,118.4	0.0	197,274.9

Table 12-3 and Figure 12-1 show the age of existing PJM generators, by unit type, as of March 31, 2021. Of the 197,274.9 MW of installed capacity, 71,985.4 MW (36.5 percent) are from units older than 40 years, of which 38,446.4 MW (53.4 percent) are coal fired steam units, 191.0 MW (0.3 percent) are combined cycle units and 16,184.6 MW (22.5 percent) are nuclear units.

Table 12-3 Capacity (MW) by unit type and age (years): March 31, 2021

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	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
Less than 20	349.0	44,971.7	16,235.2	604.5	43.8	32.0	0.0	297.2	0.0	149.7	20.0	283.4	3,987.3	0.0	0.0	3,475.0	82.0	0.0	97.4	11,118.4	0.0	81,746.5
20 to 40	0.0	5,031.3	7,950.8	355.5	0.0	0.0	3,003.0	427.2	17,268.0	12.0	25.0	71.0	0.0	0.0	0.0	7,956.0	600.0	0.0	843.1	0.0	0.0	43,542.9
40 to 60	0.0	191.0	469.7	3,002.4	0.0	0.0	2,049.0	340.0	16,184.6	0.0	173.5	0.0	0.0	0.0	0.0	35,593.6	5,971.1	1,350.0	70.0	0.0	0.0	65,394.9
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	0.0	0.0	2,852.8	1,761.5	0.0	0.0	0.0	0.0	6,590.5
Total	349.0	50,194.0	24,655.7	3,962.4	43.8	32.0	5,052.0	3,040.6	33,452.6	161.7	218.5	354.4	3,987.3	0.0	0.0	49,877.4	8,414.6	1,350.0	1,010.5	11,118.4	0.0	197,274.9

Figure 12-1 Capacity (MW) by age (years): March 31, 2021

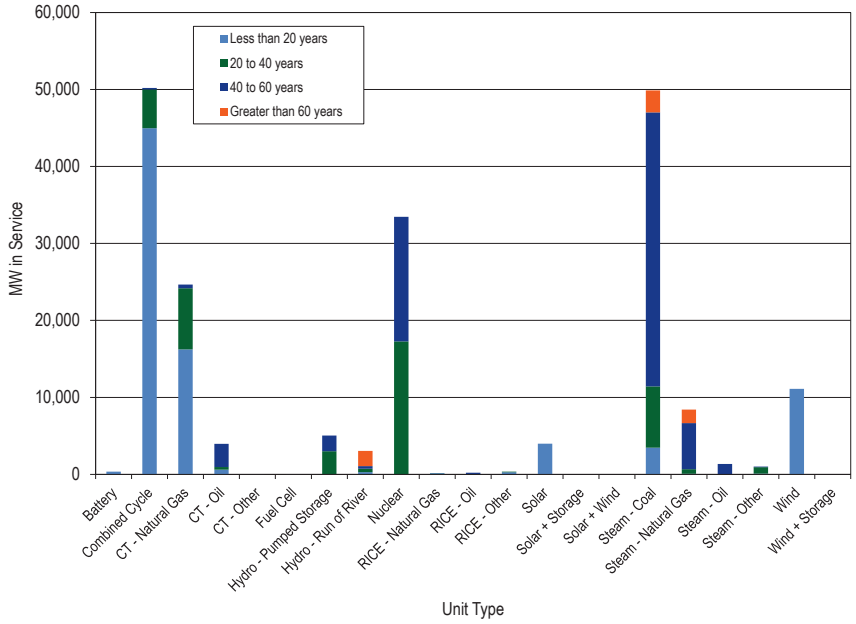


Figure 12-2 is a map of units, less than 20 MW in size, that came online between January 1, 2011 and March 31, 2021. A mapping to these unit names is in Table 12-4.

Figure 12-2 Map of unit additions (less than 20 MW): January 1, 2011 through March 31, 2021

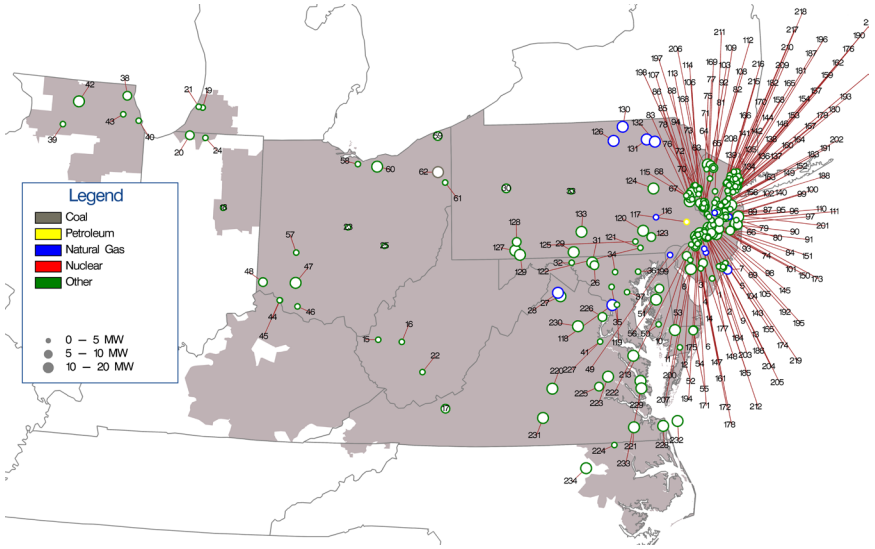


Table 12-4 Unit identification for map of unit additions (less than 20 MW): January 1, 2011 through March 31, 2021

ID	Unit	ID	Unit	ID	Unit	ID	Unit	ID	Unit
1	ACE CAPE MAY COUNTY 1 LF	56	DPL WYE MILLS 1 SP	111	JC UPPER FREEHOLD 1 SP	166	PS HINCHMANS SOLAR 1 SP	221	VP GARDNER FARMS 1 SP
2	ACE CATES ROAD 2 SP	57	FE DOVETAIL 1 CT	112	JC WANTAGE 2 SP	167	PS HOBOKEN SOLAR 2 SP	222	VP GARDYS MILL ROAD 5 SP
3	ACE CEDAR BRANCH 1 SP	58	FE ERIE COUNTY 1 LF	113	JC WARREN 1 SP	168	PS HOPEWELL 1 SP	223	VP HOLLYFIELD 1 SP
4	ACE EGG HARBOR-KELLOGG 1 FC	59	FE GENEVA 1 LF	114	JC WASHBURN AVE 4 SP	169	PS HOPEWELL 2 BT	224	VP MURPHY 1 SP
5	ACE GALLOWAY LANDFILL 2 SP	60	FE LORAIN 1 LF	115	ME GLENDON 1 LF	170	PS JACKSON SOLAR 1 SP	225	VP NORTHEAST 2 LF
6	ACE MAYS LANDING 1 SP	61	FE MAHONING 1 LF	116	ME READING HOSPITAL 1 CT	171	PS KINSLEY BEAVER 2 SP	226	VP OCCOQUAN 1 LF
7	ACE MIDTOWN THERMAL 2 CT	62	FE WARREN-EVERGREEN 1 CT	117	PE MORRIS ROAD 1 D	172	PS KINSLEY DEPTFORD 1 SP	227	VP OCCOQUAN 2 LF
8	ACE OAK FAIRTON 1 SP	63	JC AUGUSTA 1 SP	118	PEP CAPITAL POWER PLANT 1 CT	173	PS KUSER SOLAR 1 SP	228	VP OCEANA 1 SP
9	ACE PEAR STREET 1 SP	64	JC BEAVER RUN 3 SP	119	PEP ROLLINS AVENUE 3 SP	174	PS LANDFILL 5 SP	229	VP PULLER 1 SP
10	ACE PILESGROVE 1 SP	65	JC BERNARDS TOWNSHIP 1 SP	120	PL DART CONTAINER 1-2 LF	175	PS LAWNSIDE 14 BT	230	VP REMINGTON 1 SP
11	ACE PILESGROVE 2 SP	66	JC BRICKYARD 4 SP	121	PL HOLTWOOD 11	176	PS LEONIA SOLAR 1 SP	231	VP TWITTYS CREEK 1 SP
12	ACE PITTSGROVE 1 SP	67	JC COPPER HILL 4 SP	122	PL HOLTWOOD 13	177	PS LUMBERTON STACY HAINES 5 SP	232	VP VIRGINIA OFFSHORE 1 WF
13	ACE SEASHORE 1 SP	68	JC CYPHERS ROAD 5 SP	123	PL KEYSTONE 1 SP	178	PS MANTUA CREEK 7 BT	233	VP WAN - GLOUCESTER 1 SP
14	ACE TANSBORO ROAD 1 FC	69	JC DIXSOLAR 5 SP	124	PL PA SOLAR 1 SP	179	PS MARION SOLAR 1 SP	234	VP WHITAKERS 1 SP
15	AEP BALLS GAP 1 BT	70	JC DOMIN LANE 1 SP	125	PL TURKEY HILL 1 WF	180	PS MATRIX PA SOLAR 2 SP		
16	AEP CHARLESTON 1 LF	71	JC DURBAN AVENUE 1 SP	126	PN ALPACA GLORY BARN 1 D	181	PS MAYWOOD SOLAR 1 SP		
17	AEP CLOYDS MT 1 LF	72	JC E FLEMINGTON 5 SP	127	PN GARRETT 1 BT	182	PS METRO HQ 2 SP		
18	AEP DEERCREEK 1 SP	73	JC EAST AMWELL 7 SP	128	PN LAUREL HIGHLANDS 2 LF	183	PS MIDDLESEX 1 SP		
19	AEP EAST WATERVLIET 1 SP	74	JC EGYPT 3 SP	129	PN MEYERSDALE 2 BT	184	PS MILL CREEK 1 SP		
20	AEP OLIVE 1 SP	75	JC FISCHER 8 SP	130	PN MILAN ENERGY 1 D	185	PS MOORESTOWN 1 SP		
21	AEP ORCHARD HILLS 1 LF	76	JC FOUL RIFT ROAD 1 SP	131	PN NORTH MESHOPPEN 1 CT	186	PS MT LAUREL 1 SP		
22	AEP RALEIGH COUNTY 1 LF	77	JC FRANKFORD 4 SP	132	PN OXBOW CREEK ENERGY CENTER 1 D	187	PS NEW MILFORD SOLAR 1 SP		
23	AEP TRENT 1 BT	78	JC FRANKLIN 7 SP	133	PN WHITETAIL 1 SP	188	PS NEW ROAD 1 SP		
24	AEP TWINBRANCH 1 SP	79	JC FREEMALL 1 FC	134	PS ALDENE SOLAR 1 SP	189	PS NEWARK SOLAR 1 SP		
25	AEP ZANESVILLE 2 LF	80	JC FRENCHES 2 SP	135	PS ATHENIA SOLAR 1 SP	190	PS NEWARK SOLAR 3 SP		
26	AP BAKER POINT 1 SP	81	JC FRENCHTOWN 1 SP	136	PS BAYONNE 1 SP	191	PS NIXON LANE 2 SP		
27	AP DOUBLE TOLLGATE SP	82	JC FRENCHTOWN 2 SP	137	PS BAYONNE SOLAR 2 SP	192	PS NORTH AMERICAN 4 SP		
28	AP HP HOOD 1 CT	83	JC FRENCHTOWN 3 SP	138	PS BELLEVILLE SOLAR 1 SP	193	PS NORTH AVE SOLAR 1 SP		
29	AP LETZBURG - ELK HILL 2 SP	84	JC HANOVER 2 SP	139	PS BENNETTS SOLAR 1 SP	194	PS OWENS CORNING 1 SP		
30	AP MAHONING CREEK 1 H	85	JC HARMONY 1 SP	140	PS BLACK ROCK 1 SP	195	PS PARKLANDS 1 SP		
31	AP MT ST MARYS PV PARK 2 SP	86	JC HIGH STREET 6 SP	141	PS BRIDGEWATER SOLAR 2 SP	196	PS PATERSON PLANK ROAD 1 SP		
32	AP PINESBURG 1 SP	87	JC HOFFMAN STATION ROAD 2 SP	142	PS CALDWELL PUMP 2 BT	197	PS PENNINGTON 3 BT		
33	AP STATE COLLEGE 1 BT	88	JC HOLLAND 4 SP	143	PS CAMPUS DRIVE 2 SP	198	PS PENNINGTON 4 SP		
34	BC ALPHA RIDGE 1 LF	89	JC HOLMDEL 9 SP	144	PS CEDAR GROVE SOLAR 1 SP	199	PS PENNSAUKEN 1 LF		
35	BC BRIGHTON DAM 1 H	90	JC HOWELL 1 SP	145	PS CEDAR LANE FLORENCE 6 SP	200	PS PENNSAUKEN 3 SP		
36	BC KINGSVILLE 1 SP	91	JC JACOBSTOWN 1 SP	146	PS COOK ROAD SOLAR 2 SP	201	PS PRINCETON HOSPITAL 1 CT		
37	BC MILLERSVILLE 1 LF	92	JC JUNCTION ROAD 6 SP	147	PS COOPER HOSPITAL 1 BT	202	PS RARITAN CENTER 3 SP		
38	COM COUNTRYSIDE 1 LF	93	JC LAKEHURST 3 SP	148	PS COOPER HOSPITAL 15 SP	203	PS REEVES EAST 3 SP		
39	COM DIXON LEE 5 LF	94	JC LEBANON 1 SP	149	PS CRANBURY 2 SP	204	PS REEVES SOUTH 1 SP		
40	COM GRAND RIDGE 6 BT	95	JC MANALAPAN 1 SP	150	PS CROSSWIC 1 SP	205	PS REEVES WEST 4 SP		
41	COM MORRIS 1 LF	96	JC MILLHURST 3 SP	151	PS CROSSWIC 2 SP	206	PS RIDER UNIVERSITY 3 SP		
42	COM ORCHARD 1 LF	97	JC MUDDY FORGE 3 SP	152	PS DEVILSBROOK 1 SP	207	PS RIVER ROAD 2 SP		
43	COM SOLBERG 1 BT	98	JC NORTH HANOVER 4 SP	153	PS DOREMUS SOLAR 1 SP	208	PS ROSELAND SOLAR 1 SP		
44	DEOK BECKJORD 1 BT	99	JC NORTH PARK 1 SP	154	PS E RUTHERFORD SOLAR 1 SP	209	PS SADDLE BROOK SOLAR 1 SP		
45	DEOK BECKJORD 2 BT	100	JC NORTH PARK 2 SP	155	PS EASTAMPTON 1 SP	210	PS SPRINGFIELD SOLAR 1 SP		
46	DEOK BROWN COUNTY 1 LF	101	JC NORTH RUN 11 SP	156	PS EDISON 1 SP	211	PS SUNNYMEADE SOLAR 1 SP		
47	DEOK CLINTON 1 BT	102	JC OLD BRIDGE 1 SP	157	PS ESSEX 105 CT	212	PS TAYLORS LANE 1 SP		
48	DEOK WILLEY 1 BT	103	JC PAUCH 3 SP	158	PS FAIRLAWN SOLAR 1 SP	213	PS THOROFARE SOLAR 2 SP		
49	DPL BLOOM ENERGY 1 FC	104	JC PEMBERTON 1 SP	159	PS FOODBANK 1 SP	214	PS TURNPIKE 1 SP		
50	DPL BUCKTOWN 1 SP	105	JC PEMBERTON 2 SP	160	PS FORTY NINTH SOLAR 1 SP	215	PS W CALDWELL SOLAR 1 SP		
51	DPL CHURCH HILL 1 SP	106	JC QUAKERTOWN 9 SP	161	PS GLOUCESTER SOLAR 1 SP	216	PS W CALDWELL SOLAR 2 SP		
52	DPL COSTEN 1 SP	107	JC RICHLINE 3 SP	162	PS HACKENSACK 1 SP	217	PS WALDWICK SOLAR 1 SP		
53	DPL HEBRON 1 SP	108	JC RINGOES 1 SP	163	PS HIGHLAND PARK 3 BT	218	PS WEST ORANGE SOLAR 1 SP		
54	DPL WORCESTER NORTH 1 SP	109	JC SUSSEX 1 LF	164	PS HIGHLAND PARK 4 SP	219	PS WEST PEMBERTON 1 SP		
55	DPL WORCESTER SOUTH 2 SP	110	JC TINTON FALLS 3 SP	165	PS HILLSDALE SOLAR 1 SP	220	VP BUCKINGHAM 1 SP		

Figure 12-3 is a map of units, 20 MW or greater in size, that came online between January 1, 2011 and March 31, 2021. A mapping to these unit names is in Table 12-5.

Figure 12-3 Map of unit additions (20 MW or greater): January 1, 2011 through March 31, 2021

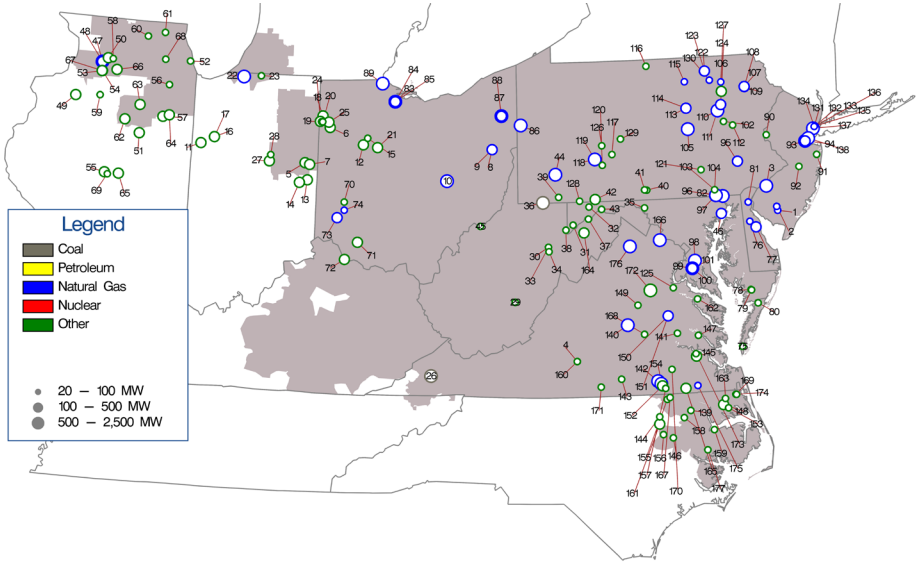


Table 12-5 Unit identification for map of unit additions (20 MW or greater): January 1, 2011 through March 31, 2021

ID	Unit	ID	Unit	ID	Unit	ID	Unit
1	ACE CLAYVILLE 1 CT	51	COM BRIGHT STALK 1 WF	101	PEP ST CHARLES-KELSON RIDGE 2 CC	151	VP DOSWELL 3 CT
2	ACE VINELAND 11 CT	52	COM GRAND RIDGE 7 BT	102	PL HAZEL 1 FW	152	VP DRY BREAD 1 SP
3	ACE WEST DEPTFORD CROWN POINT 1 CC	53	COM GREEN RIVER 1 WF	103	PL HOLTWOOD 18	153	VP ELIZABETH CITY 1 SP
4	AEP ALTAVISTA 1 SP	54	COM GREEN RIVER 2 WF	104	PL HOLTWOOD 19	154	VP GREENSVILLE 1 CC
5	AEP BITTER RIDGE 1 WF	55	COM HILLTOPPER 1 WF	105	PL HUMMEL STATION 1 CC	155	VP GUTENBERG - OCONECHE 1 SP
6	AEP BLUE CREEK 3 WF	56	COM JOLIET 1 BT	106	PL HUNLOCK CC	156	VP HARTS MILL 1 SP
7	AEP BLUFF POINT 2 WF	57	COM KELLY CREEK 1 WF	107	PL LACKAWANNA COUNTY 1 CC	157	VP IVORY LANE 1 SP
8	AEP CARROLL COUNTY 1 CC	58	COM LEE DEKALB 3 BT	108	PL LACKAWANNA COUNTY 2 CC	158	VP KELFORD 1 SP
9	AEP CARROLL COUNTY 2 CC	59	COM LONE TREE 3 WF	109	PL LACKAWANNA COUNTY 3 CC	159	VP MACKEYS 1 SP
10	AEP DRESDEN 1 CC	60	COM MARENGO 1 BT	110	PL MOXIE FREEDOM 11 CC	160	VP MECHANICSVILLE 2 SP
11	AEP FOWLER RIDGE 4 WF	61	COM MCHENRY 1 BT	111	PL MOXIE FREEDOM 21 CC	161	VP MOCCASIN CREEK 1 SP
12	AEP HARDIN 2 SP	62	COM MINONK 1 WF	112	PL PA SOLAR 2 SP	162	VP MONTROSS 1 SP
13	AEP HEADWATERS 1 WF	63	COM OTTER CREEK 1 WF	113	PL PATRIOT 1 F	163	VP MORGAN CORNER 1 SP
14	AEP HEADWATERS 2 WF	64	COM PILOT HILL 1 WF	114	PL PATRIOT 2 F	164	VP NEW CREEK 1 WF
15	AEP HOG CREEK 1 WF	65	COM RADFORDS RUN 1 WF	115	PN BEAVER DAM 1 D	165	VP NEWSOMS 1 SP
16	AEP MEADOW LAKE 5 WF	66	COM SHADY OAKS 1 WF	116	PN BIG LEVEL 1 WF	166	VP PANDA STONEWALL 1 CC
17	AEP MEADOW LAKE 6 WF	67	COM WALNUT RIDGE 1 WF	117	PN CHESTNUT FLATS 1 WF	167	VP PECAN 1 SP
18	AEP PAULDING 3 WF	68	COM WEST CHICAGO 3 BT	118	PN FAIRVIEW 1 CC	168	VP POWHATAN 2 SP
19	AEP PAULDING 41 WF	69	COM WHITNEY HILL 2 WF	119	PN FAIRVIEW 2 CC	169	VP RANCHLAND 2 SP
20	AEP PAULDING 42 WF	70	DAY TAIT 8 BT	120	PN HIGHLAND NORTH 2 WF	170	VP SAPONY 1 SP
21	AEP SCIOTO RIDGE 1 WF	71	DEOK HILLCREST 1 SP	121	PN LAUREL HILLS 1 WF	171	VP SOUTH BOSTON 1 F
22	AEP ST JOSEPH ENERGY CENTER 1 CC	72	DEOK MELDAHL DAM 1 H	122	PN LIBERTY ASYLUM 10 F	172	VP SPOTSYLVANIA 1 SP
23	AEP ST JOSEPH SOLAR PARK 1 SP	73	DEOK MIDDLETOWN ENERGY 1 CC	123	PN LIBERTY ASYLUM 20 F	173	VP SPRING GROVE 1 SP
24	AEP TIMBER2 1 WF	74	DEOK YANKEE 1 F	124	PN MEHOOPANY 1 WF	174	VP SUMMIT FARMS 1 SP
25	AEP TRISHE 1 WF	75	DPL CHERRYDALE 1 SP	125	PN MEHOOPANY 2 WF	175	VP UNION CAMP 9-10 F
26	AEP VIRGINIA CITY 1 F	76	DPL DEMEC - CLAYTON 2 CT	126	PN PATTON 1 WF	176	VP WARREN COUNTY FRONT ROYAL CC
27	AEP WILDCAT 1A WF	77	DPL GARRISON EC 1 CC	127	PN PGCOGEN 2 CT	177	VP WILKINSON ENERGY CENTER 1 SP
28	AEP WILDCAT 1B WF	78	DPL GREAT BAY KINGS CREEK 1 SP	128	PN RINGER HILL 1 WF		
29	AP BEECH RIDGE 2 WF	79	DPL GREAT BAY KINGS CREEK 2 SP	129	PN SANDY RIDGE 1 WF		
30	AP BEECH RIDGE 3 BT	80	DPL OAK HALL 1 SP	130	PN SUGAR RUN 2 CT		
31	AP FAIR WIND 2 WF	81	DPL RED LION 1 FC	131	PS KEARNY 131 CT		
32	AP FOURMILE RIDGE 1 WF	82	DPL WILDCAT POINT 1 CC	132	PS KEARNY 132 CT		
33	AP LAUREL MOUNTAIN 1 BT	83	FE FREMONT 1 SCCT	133	PS KEARNY 133 CT		
34	AP LAUREL MOUNTAIN 1 WF	84	FE FREMONT 2 SCCT	134	PS KEARNY 134 CT		
35	AP MARLOWE 1 SP	85	FE FREMONT ENERGY CENTER 3 CC	135	PS KEARNY 141 CT		
36	AP NORTH LONGVIEW 1 F	86	FE HICKORY RUN 1 CC	136	PS KEARNY 142 CT		
37	AP PINNACLE 1 WF	87	FE LORDSTOWN ENERGY CENTER 1 CC	137	PS NEWARK ENERGY CENTER 10 CC		
38	AP ROTH ROCK 1 WF	88	FE LORDSTOWN ENERGY CENTER 2 CC	138	PS SEWAREN 7 CC		
39	AP SOUTH CHESTNUT 1 WF	89	FE OREGON ENERGY CENTER 1 CC	139	VP AULANDER HOLLOMAN 1 SP		
40	AP ST THOMAS 1 SP	90	JC EDGE ROAD 5 BT	140	VP BEAR GARDEN		
41	AP ST THOMAS 2 SP	91	JC HAMILTON ROAD 5 SP	141	VP BRIEL FARM 1 SP		
42	AP TWIN RIDGES 1 WF	92	JC PLUMSTED ENERGY 6 BT	142	VP BRUNSWICK 1CC		
43	AP WARRIOR RUN 2 BT	93	JC WOODBRIDGE 1 CC	143	VP BUTCHER CREEK 1 SP		
44	AP WESTMORELAND 1 CC	94	JC WOODBRIDGE 2 CC	144	VP CHESTNUT 1 SP		
45	AP WILLOW ISLAND 1 H	95	ME BIRDSBORO 1 CC	145	VP COLONIAL TRAIL WEST 1 SP		
46	BC PERRYMAN 6 CT	96	PE DELTA 1-4 CC	146	VP CONETOE 2 SP		
47	COM 942 NELSON 1 CC	97	PE DELTA 5-7 CC	147	VP CORRECTIONAL 1 SP		
48	COM 942 NELSON 2 CC	98	PEP KEYS ENERGY CENTER 1 CC	148	VP DESERT 1 WF		
49	COM BISHOP HILL SP in PJM WF	99	PEP ST CHARLES - KELSON RIDGE 1 CC	149	VP DESPER 1 SP		
50	COM BLOOMING GROVE 1 WF1	100	PEP ST CHARLES-KELSON RIDGE 1 CC	150	VP DOSWELL 2 CT		

Generation Retirements[16] [17]

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.[18] 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.[19]

Rules that preserve the Capacity Interconnection Rights (CIRs) associated with retired units, and with the conversion from Capacity Performance (CP) to energy only status, 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.[20] There are currently no rules governing the retention of CIRs when units want to convert to energy only status or require time to upgrade to retain CP status. The rules governing conversion or upgrades should be the same as the rules governing retired units. 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.[21] The MMU recognized the progress made in this rule change, but it did not fully address the issues. The MMU recommends that the question of whether CIRs should persist after the retirement of a unit, or conversion from CP to energy only status, be addressed. The rules need to ensure that incumbents cannot exploit control of CIRs to block or postpone entry of competitors.[22]

16 See PJM. Planning. "Generator Deactivations," (Accessed on March 31, 2021) <http://www.pjm.com/planning/services-requests/gen-deactivations.aspx>.

17 Generation retirements reported in this section do not include external units. Therefore, retirement totals reported in this section may not match totals reported elsewhere in this report where external units are included.

18 See OATT Section V and Attachment M–Appendix § IV.

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

20 See OATT § 230.3.3.

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

22 See "Comments of the Independent Market Monitor for PJM," Docket No. ER12-1177-000 (March 12, 2012) <http://www.monitoringanalytics.com/Filings/2012/IMM_Comments_ER12-1177-000_20120312.PDF>.

Generation Retirements 2011 through 2024

Table 12-6 shows that as of March 31, 2021, there are 45,070.3 MW of generation that have been, or are planned to be, retired between 2011 and 2024, of which 32,084.1 MW (71.2 percent) are coal fired steam units. Retirements are primarily a result of the inability of coal and other units to compete with efficient combined cycle units burning low cost gas.

Table 12-6 Summary of unit retirements by unit type (MW): 2011 through 2024

	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	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
Retirements 2011	0.0	0.0	0.0	128.3	0.0	0.0	0.0	0.0	0.0	0.0	2.7	0.0	0.0	0.0	0.0	543.0	522.5	0.0	0.0	0.0	0.0	1,196.5
Retirements 2012	0.0	0.0	250.0	240.0	0.0	0.0	0.0	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	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	0.0	0.0	2,589.9	82.0	166.0	8.0	0.0	0.0	2,858.8
Retirements 2014	0.0	0.0	136.0	422.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	15.3	0.0	0.0	0.0	2,239.0	158.0	0.0	0.0	0.0	0.0	2,970.3
Retirements 2015	0.0	0.0	1,319.0	856.2	2.0	0.0	0.0	0.0	0.0	0.0	10.3	0.0	0.0	0.0	0.0	7,064.8	0.0	0.0	0.0	10.4	0.0	9,262.7
Retirements 2016	0.0	0.0	0.0	65.0	6.0	0.0	0.5	0.0	0.0	0.0	8.0	3.9	0.0	0.0	0.0	243.0	74.0	0.0	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	0.0	0.0	2,038.0	34.0	0.0	0.0	0.0	0.0	2,112.8
Retirements 2018	1.0	425.0	0.0	38.0	1.6	0.0	0.0	0.0	614.5	0.0	17.2	6.9	0.0	0.0	0.0	3,186.5	996.0	148.0	108.0	0.0	0.0	5,542.7
Retirements 2019	0.0	0.0	346.8	51.4	6.4	0.0	0.0	0.0	805.0	0.0	0.0	15.9	0.0	0.0	0.0	4,113.8	97.0	10.0	10.0	0.0	0.0	5,456.3
Retirements 2020	0.0	0.0	232.5	24.0	6.0	0.0	0.0	0.0	0.0	0.0	0.0	14.7	0.0	0.0	0.0	2,131.8	0.0	786.0	60.0	0.0	0.0	3,255.0
Retirements 2021	2.0	67.0	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	353.4	0.0	0.0	0.0	0.0	0.0	430.4
Planned Retirements (April 2021 and later)	2.0	51.0	80.0	28.0	0.0	0.0	0.0	0.0	1,786.5	0.0	0.0	0.0	0.0	0.0	0.0	1,673.0	952.0	0.0	50.0	0.0	0.0	4,622.5
Total	45.0	543.0	2,364.3	1,852.9	22.0	0.0	0.5	0.0	3,206.0	0.0	44.1	72.5	0.0	0.0	0.0	32,084.1	2,915.5	1,658.0	252.0	10.4	0.0	45,070.3

Table 12-7 shows the capacity, average size, and average age of units retiring in PJM, from 2011 through 2024, while Table 12-8 shows these retirements by state. Of the 45,070.3 MW of units that has been, or are planned to be, retired between 2011 and 2024, 32,084.1 MW (71.2 percent) are coal fired steam units. These coal fired steam units have an average age of 52.7 years and an average size of 188.7 MW. Over half of the retiring coal fired steam units, 55.9 percent, are located in Ohio or Pennsylvania.

Table 12-7 Retirements by unit type: 2011 through 2024

Unit Type	Number of Units	Avg. Size (MW)	Avg. Age at Retirement (Years)	Total MW	Percent
Battery	4	11.3	5.9	45.0	0.1%
Combined Cycle	4	135.8	29.1	543.0	1.2%
Combustion Turbine	116	26.7	34.8	4,239.2	9.4%
Natural Gas	60	39.4	40.9	2,364.3	5.2%
Oil	50	37.1	44.3	1,852.9	4.1%
Other	6	3.7	19.2	22.0	0.0%
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	4	801.5	49.1	3,206.0	7.1%
RICE	28	4.2	28.5	116.6	0.3%
Natural Gas	0	0.0	0.0	0.0	0.0%
Oil	10	4.4	45.7	44.1	0.1%
Other	18	4.0	11.2	72.5	0.2%
Solar	0	0	0	0	0.0%
Solar + Storage	0	0	0	0	0.0%
Solar + Wind	0	0	0	0	0.0%
Steam	203	162.5	45.5	36,909.6	81.9%
Coal	170	188.7	52.7	32,084.1	71.2%
Natural Gas	19	153.4	60.0	2,915.5	6.5%
Oil	6	276.3	45.6	1,658.0	3.7%
Other	8	31.5	23.8	252.0	0.6%
Wind	1	10.4	15.6	10.4	0.0%
Wind + Storage	0	0	0	0	0.0%
Total	361	124.8	45.6	45,070.3	100.0%

Table 12-8 Retirements (MW) by unit type and state: 2011 through 2024

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	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
DC	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	0.0	0.0	0.0	548.0	0.0	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	0.0	0.0	254.0	136.0	0.0	0.0	0.0	0.0	390.0
IL	0.0	0.0	296.0	0.0	0.0	0.0	0.0	0.0	1,786.5	0.0	0.0	20.4	0.0	0.0	0.0	1,624.0	0.0	0.0	0.0	0.0	0.0	3,726.9
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	0.0	0.0	982.0	0.0	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	0.0	0.0	995.0	0.0	0.0	0.0	0.0	0.0	995.0
MD	0.0	0.0	347.5	104.0	1.6	0.0	0.0	0.0	0.0	0.0	0.0	0.8	0.0	0.0	0.0	1,839.0	171.0	0.0	0.0	0.0	0.0	2,463.9
NC	0.0	0.0	0.0	31.0	0.0	0.0	0.0	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	0.0	355.5
NJ	0.0	225.0	1,590.0	1,040.2	6.4	0.0	0.5	0.0	614.5	0.0	8.0	19.5	0.0	0.0	0.0	1,543.0	932.5	148.0	10.0	0.0	0.0	6,137.6
OH	42.0	0.0	0.0	286.0	0.0	0.0	0.0	0.0	0.0	0.0	19.3	5.4	0.0	0.0	0.0	13,179.4	0.0	0.0	0.0	0.0	0.0	13,532.1
PA	1.0	51.0	50.8	72.0	14.0	0.0	0.0	0.0	805.0	0.0	13.9	18.0	0.0	0.0	0.0	4,734.3	1,133.0	176.0	109.0	10.4	0.0	7,188.4
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	0.0	0.0	50.0	0.0	0.0	50.0
VA	0.0	267.0	80.0	79.7	0.0	0.0	0.0	0.0	0.0	0.0	2.9	8.4	0.0	0.0	0.0	3,917.9	543.0	786.0	83.0	0.0	0.0	5,767.9
WV	2.0	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	2,691.0	0.0	0.0	0.0	0.0	0.0	2,693.0
Total	45.0	543.0	2,364.3	1,852.9	22.0	0.0	0.5	0.0	3,206.0	0.0	44.1	72.5	0.0	0.0	0.0	32,084.1	2,915.5	1,658.0	252.0	10.4	0.0	45,070.3

Figure 12-4 is a map of unit retirements between 2011 and 2024, with a mapping to unit names in Table 12-9.

Figure 12-4 Map of unit retirements: 2011 through 2024

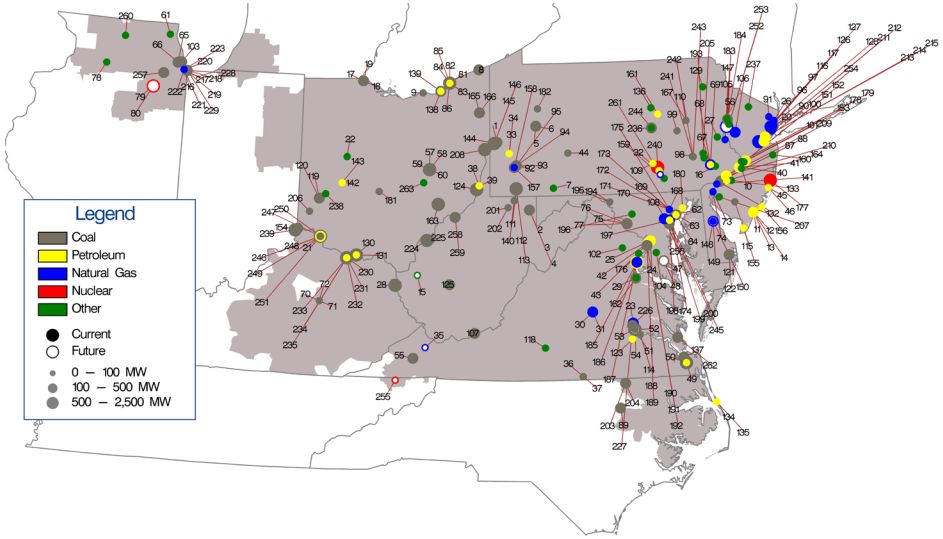


Table 12-9 Unit identification for map of unit retirements: 2011 through 2024

ID	Unit	ID	Unit	ID	Unit	ID	Unit	ID	Unit
1	AES Beaver Valley	56	Columbia Dam Hydro	111	Hatfield's Ferry 1	166	Niles 2	221	Southeast Chicago CT8
2	Albright 1	57	Conesville 3	112	Hatfield's Ferry 2	167	Northeastern Power NEPCO	222	Southeast Chicago GT10
3	Albright 2	58	Conesville 4	113	Hatfield's Ferry 3	168	Notch Cliff GT1	223	Southeast Chicago GT9
4	Albright 3	59	Conesville 5	114	Hopewell James River Cogeneration	169	Notch Cliff GT2	224	Sporn 1-4
5	Armstrong 1	60	Conesville 6	115	Howard Down 10	170	Notch Cliff GT3	225	Sporn 5
6	Armstrong 2	61	Countryside Landfill	116	Hudson 1	171	Notch Cliff GT4	226	Spruance NUG1 (Rich 1-2)
7	Arnold (Green Mtn. Wind Farm	62	Crane 1	117	Hudson 2	172	Notch Cliff GT5	227	Spruance NUG2 (Rich 3-4)
8	Ashtabula 5	63	Crane 2	118	Hurt NUG	173	Notch Cliff GT6	228	State Line 3
9	Avon Lake 7	64	Crane GT1	119	Hutchings 1-3, 5-6	174	Notch Cliff GT7	229	State Line 4
10	BC Landfill	65	Crawford 7	120	Hutchings 4	175	Notch Cliff GT8	230	Stuart 1
11	BL England 1	66	Crawford 8	121	Indian River 1	176	Occoquan 1 LF	231	Stuart 2
12	BL England 2	67	Cromby 1	122	Indian River 3	177	Oyster Creek	232	Stuart 3
13	BL England 3	68	Cromby 2	123	Ingenco Petersburg	178	Pennsbury Generator Landfill 1	233	Stuart 4
14	BL England Diesel Units 1-4	69	Cromby D	124	Kammer 1-3	179	Pennsbury Generator Landfill 2	234	Stuart Diesels 1-4
15	Balls Gap Battery Facility	70	Dale 1-2	125	Kanawha River 1-2	180	Perryman 2	235	Stuart Diesels 1-4
16	Barbados AES Battery	71	Dale 3	126	Kearny 10	181	Picway 5	236	Sunbury 1-4
17	Bay Shore 2	72	Dale 4	127	Kearny 11	182	Piney Creek NUG	237	Sussex County LF
18	Bay Shore 3	73	Deepwater 1	128	Kearny 9	183	Portland 1	238	Tait Battery
19	Bay Shore 4	74	Deepwater 6	129	Keystone Recovery (Units 1 - 7)	184	Portland 2	239	Tanners Creek 1-4
20	Bayonne Cogen Plant (CC)	75	Dickerson Unit 1	130	Killen 2	185	Possum Point 3	240	Three Mile Island Unit 1
21	Beckjord Battery Unit 2	76	Dickerson Unit 2	131	Killen CT	186	Possum Point 4	241	Titus 1
22	Bellefontaine Landfill Generating Station	77	Dickerson Unit 3	132	Kimberly Clark Generator	187	Possum Point 5	242	Titus 2
23	Bellemeade	78	Dixon Lee Landfill Generator	133	Kinsley Landfill	188	Potomac River 1	243	Titus 3
24	Benning 15	79	Dresden 2	134	Kitty Hawk GT 1	189	Potomac River 2	244	Viking Energy NUG
25	Benning 16	80	Dresden 3	135	Kitty Hawk GT 2	190	Potomac River 3	245	Wagner 2
26	Bergen 3	81	Eastlake 1	136	Koppers Co. IPP	191	Potomac River 4	246	Walter C Beckjord 1
27	Bethlehem Renewable Energy Generator (Landfill)	82	Eastlake 2	137	Lake Kingman	192	Potomac River 5	247	Walter C Beckjord 2
28	Big Sandy 2	83	Eastlake 3	138	Lake Shore 18	193	Pottstown LF (Moser)	248	Walter C Beckjord 3
29	Birchwood Plant	84	Eastlake 4	139	Lake Shore EMD	194	R Paul Smith 3	249	Walter C Beckjord 4
30	Bremo 3	85	Eastlake 5	140	MEA NUG (WVU)	195	R Paul Smith 4	250	Walter C Beckjord 5-6
31	Bremo 4	86	Eastlake 6	141	MH50 Markus Hook Co-gen	196	Reichs Ford Road Landfill Generator	251	Walter C Beckjord GT 1-4
32	Brunner Island Diesels	87	Eddystone 1	142	Mad River CTs A	197	Riverside 4	252	Warren County Landfill
33	Brunot Island 1B	88	Eddystone 2	143	Mad River CTs B	198	Riverside 6	253	Warren County NUG
34	Brunot Island 1C	89	Edgecomb NUG (Rocky 1-2)	144	Mansfield 1	199	Riverside 7	254	Werner 1-4
35	Buchanan 1-2	90	Edison 1-3	145	Mansfield 2	200	Riverside 8	255	West Kingsport LF
36	Buggs Island 1 (Mecklenberg)	91	Elmwood Park Power	146	Mansfield 3	201	Riversville 5	256	Westport 5
37	Buggs Island 2 (Mecklenberg)	92	Elrama 1	147	Martins Creek CT 4	202	Riversville 6	257	Will County 3
38	Burger 3	93	Elrama 2	148	McKee 1	203	Roanoke Valley 1	258	Willow Island 1
39	Burger EMD	94	Elrama 3	149	McKee 2	204	Roanoke Valley 2	259	Willow Island 2
40	Burlington 8,11	95	Elrama 4	150	McKee 3	205	Rolling Hills Landfill Generator	260	Winnebago Landfill
41	Burlington 9	96	Essex 10-11	151	Mercer 1	206	SMART Paper	261	York Generation Facility
42	Buzzard Point East Banks 1,2,4-8	97	Essex 12	152	Mercer 2	207	Salem County LF	262	Yorktown 1-2
43	Buzzard Point West Banks 1-9	98	Evergreen Power United Corstack	153	Mercer 3	208	Sammis 1-4	263	Zanesville Landfill
44	Cambria CoGen	99	FRACKVILLE WHEELABRATOR 1	154	Miami Fort 6	209	Schuylkill 1		
45	Cedar 1	100	Fairless Hills Landfill A	155	Middle 1-3	210	Schuylkill Diesel		
46	Cedar 2	101	Fairless Hills Landfill B	156	Missouri Ave B,C,D	211	Sewaren 1		
47	Chalk Point Unit 1	102	Fauquier County Landfill	157	Mitchell 2	212	Sewaren 2		
48	Chalk Point Unit 2	103	Fisk Street 19	158	Mitchell 3	213	Sewaren 3		
49	Chesapeake 1-4	104	GUDE Landfill	159	Modern Power Landfill NUG	214	Sewaren 4		
50	Chesapeake 7-10	105	Gilbert 1-4	160	Monmouth NUG landfill	215	Sewaren 6		
51	Chesterfield 3	106	Glen Gardner 1-8	161	Montour ATG	216	Southeast Chicago CT11		
52	Chesterfield 4	107	Glen Lyn 5-6	162	Morris Landfill Generator	217	Southeast Chicago CT12		
53	Chesterfield 5	108	Gould Street Generation Station	163	Muskingum River 1-5	218	Southeast Chicago CT5		
54	Chesterfield 6	109	Harrisburg 4 CT	164	National Park 1	219	Southeast Chicago CT6		
55	Clinch River 3	110	Harwood 1-2	165	Niles 1	220	Southeast Chicago CT7		

Current Year Generation Retirements

Table 12-10 shows that in the first three months of 2021, 430.4 MW of generation retired. The largest generator that retired in the first three months of 2021 was the 237.9 MW Birchwood coal fired steam unit located in the Dominion Zone. Of the 430.4 MW of generation that retired, 353.4 MW (82.1 percent) were located in the Dominion Zone.

Table 12-10 Unit deactivations: January through March, 2021

Company	Unit Name	ICAP (MW)	Unit Type	Zone Name	Age (Years)	Retirement Date
Ares Management LP	Spruance NUG1 (aka Spruance 1 Rich 1-2)	115.5	Steam-Coal	DOM	28.7	12-Jan-21
Biogas Energy Solutions, LLC	Countryside Landfill	8.0	RICE-Other	COMED	8.5	27-Jan-21
Galt Power Inc.	Beckjord Battery Unit 2	2.0	Battery	DUKE	5.3	03-Feb-21
General Electric Company	Birchwood Plant	237.9	Steam-Coal	DOM	24.3	01-Mar-21
Riverstone Holdings LLC	Elmwood Park Power	67.0	Combined Cycle	PSEG	32.0	12-Mar-21

Planned Generation Retirements

Table 12-11 shows that, as of March 31, 2021, there are 4,622.5 MW of generation that have requested retirement after March 31, 2021, of which 1,786.5 MW (38.7 percent) are located in the COMED Zone. Of the generation requesting retirement in the COMED Zone, all 1,786.5 MW (100.0 percent) are nuclear units.

Table 12-11 Planned retirement of units: March 31, 2021

Company	Unit Name	ICAP (MW)	Unit Type	Zone Name	Projected Deactivation Date
American Electric Power Company, Inc.	Balls Gap Battery Facility	2.0	Battery	AEP	22-Apr-21
Riverstone Holdings LLC	Harwood 1-2	28.0	CT-Oil	PPL	31-May-21
Domtar Corporation	West Kingsport LF	50.0	Steam-Other	AEP	31-May-21
GenOn Energy, Inc.	Chalk Point Unit 1	331.0	Steam-Coal	PEPCO	01-Jun-21
GenOn Energy, Inc.	Chalk Point Unit 2	336.0	Steam-Coal	PEPCO	01-Jun-21
City of Dover	McKee 3	102.0	Steam-Natural Gas	DPL	01-Jun-21
Exelon Corporation	Dresden 2	883.5	Nuclear	COMED	08-Nov-21
Exelon Corporation	Dresden 3	903.0	Nuclear	COMED	29-Nov-21
Riverstone Holdings LLC	Martins Creek CT 4	850.0	Steam-Natural Gas	PPL	31-May-22
Riverstone Holdings LLC	York Generation Facility	51.0	Combined Cycle	MEC	31-May-22
Dominion Resources, Inc.	Chesterfield 5	336.0	Steam-Coal	DOM	31-May-23
Dominion Resources, Inc.	Chesterfield 6	670.0	Steam-Coal	DOM	31-May-23
LS Power Equity Partners, L.P.	Buchanan 1-2	80.0	CT-Natural-Gas	AEP	01-Jun-23
		4,622.5			

Generation Queue[23]

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.[24] 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 one 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 AG2 opened on October 1, 2020 and closed on March 31, 2021.

Projects that do not meet submission requirements are removed from the queue. All projects that have entered 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.[25] 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.[26]

The PJM queue evaluation process has been substantially improved in recent years and it is more efficient and effective as a result.[27] 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.

23 The queue totals in this report are the winter net MW energy for the interconnection requests ("MW Energy") as shown in the queue.
24 See OATT Parts IV & VI.
25 See PJM. "PJM Manual 14C: Generation and Transmission Interconnection Process," Rev. 14 (January 27, 2021).
26 PJM does not track the duration of suspensions or PJM termination of projects.
27 See *PJM Interconnection, L.L.C.*, Docket No. ER12-1177 (Feb. 29, 2012).

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 12-12 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.

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. 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 12-12 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

Process improvements have allowed PJM to continue to meet the deadlines for feasibility and system impact studies despite the increase in interconnection requests. The increase in the number of projects submitted in the queue combined with the rules for evaluating projects have contributed to a significant backlog in performing timely facility studies. The facility study includes the conceptual design, stability analyses and determines the network upgrades, and the costs associated with those upgrades. Modifications to proposed facilities and restudies resulting from the withdrawal of projects from the queue also affect the time to complete a facility study. In 2020, PJM conducted interconnection process workshops designed to review current processes, receive input and recommendations from stakeholders and to develop improvements to the process, including ways to resolve the current interconnection study backlog.

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 March 31, 2021, 177,645.3 MW 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.[28]

28 See "*PJM Generation Capacity and Funding Sources 2007/2008 through 2021/2022 Delivery Years*," <http://www.monitoringanalytics.com/reports/Reports/2020/IMM_2020_PJM_Generation_Capacity_and_Funding_Sources_20072008_through_20212022_DY_20200915.pdf>.

There were 173,182.4 MW in generation queues, in the status of active, under construction or suspended, at the end of 2020. The AG2 queue remained open during the first three months of 2021, closing on March 31, 2021. As projects move through the queue process, projects can be removed from the queue due to incomplete or invalid data, withdrawn by the market participant or placed in service. On March 31, 2021, there were 177,645.3 MW in generation queues, in the status of active, under construction or suspended, an increase of 4,462.9 MW (2.6 percent) from December 31, 2020. Table 12-13 shows MW in queues by expected completion year and MW changes in the queue between December 31, 2020, and March 31, 2021, for ongoing projects, i.e. projects with the status active, under construction or suspended.[29]

Table 12-13 Queue comparison by expected completion year (MW): December 31, 2020 and March 31, 2021[30]

			Year Change	
Year	As of 12/31/2020	As of 03/31/2021	MW	Percent
2008	0.0	0.0	0.0	0.0%
2009	0.0	0.0	0.0	0.0%
2010	0.0	0.0	0.0	0.0%
2011	0.0	0.0	0.0	0.0%
2012	16.1	16.1	0.0	0.0%
2013	20.0	20.0	0.0	0.0%
2014	0.0	0.0	0.0	0.0%
2015	0.0	0.0	0.0	0.0%
2016	19.4	7.4	(12.0)	(61.9%)
2017	905.8	791.8	(114.0)	(12.6%)
2018	2,054.0	1,498.0	(556.0)	(27.1%)
2019	7,898.3	7,120.4	(777.9)	(9.8%)
2020	11,896.1	11,200.7	(695.4)	(5.8%)
2021	31,545.0	32,442.2	897.2	2.8%
2022	41,605.7	42,834.1	1,228.4	3.0%
2023	41,060.4	44,558.1	3,497.7	8.5%
2024	19,435.5	24,981.1	5,545.7	28.5%
2025	3,995.6	5,070.0	1,074.4	26.9%
2026	2,645.2	4,205.2	1,560.0	59.0%
2027	2,100.1	2,100.1	0.0	0.0%
2028	0.0	0.0	0.0	0.0%
2029	800.1	800.1	0.0	0.0%
Total	165,997.3	177,645.3	11,647.9	7.0%

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

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

Table 12-14 shows the project status changes in more detail and how scheduled queue MW have changed between December 31, 2020, and March 31, 2021. For example, 11,793.3 MW entered the queue in the first three months of 2021. Of those 11,793.3 MW, 145.4 MW have been withdrawn. Of the total 156,594.4 MW marked as active on December 31, 2020, 5,930.0 MW were withdrawn, 2,106.5 MW were suspended, 1,799.8 MW started construction, and 16.5 MW went into service by March 31, 2021. Analysis of projects that were suspended on December 31, 2020 show that 513.4 MW came out of suspension and are now active as of March 31, 2021.

Table 12-14 Change in project status (MW): December 31, 2020 to March 31, 2021

		Status at 3/31/2021				
Status at 12/31/2020	Total at 12/31/2020	Active	In Service	Under Construction	Suspended	Withdrawn
(Entered during 2021)	0.0	11,647.9	0.0	0.0	0.0	145.4
Active	156,594.4	146,741.6	16.5	1,799.8	2,106.5	5,930.0
In Service	73,092.3	0.0	73,090.2	0.0	0.0	2.1
Under Construction	9,570.8	22.7	262.3	9,275.8	0.0	10.0
Suspended	7,017.3	513.4	0.0	0.0	5,447.5	1,056.4
Withdrawn	410,672.5	90.0	0.0	0.0	0.0	410,582.5
Total	656,947.3	159,015.6	73,369.0	11,075.6	7,554.0	417,726.4

On March 31, 2021, 177,645.3 MW were in generation request queues in the status of active, suspended or under construction. Table 12-15 shows each status by unit type. Of the 159,015.6 MW in the status of Active on March 31, 2021, 8,268.3 MW (5.2 percent) were combined cycle projects. Of the 11,075.6 MW in the status of under construction, 7,840.3 MW (70.8 percent) were combined cycle projects. A significant amount of renewable hybrid projects (defined as solar + storage, solar + wind and wind + storage projects) have entered the queue in recent years. Of the 159,015.6 MW in the status of Active on March 31, 2021, 19,061.6 MW (12.0 percent) were renewable hybrid projects. Of the 11,075.6 MW in the status of under construction, 5.7 MW (.05 percent) were renewable hybrid projects.

Table 12-15 Current project status (MW) by unit type: March 31, 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	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
Active	15,977.5	8,268.3	4,545.8	18.0	0.0	0.0	700.0	147.3	145.5	0.0	0.0	0.0	79,635.4	18,862.6	199.0	40.0	11.0	0.0	0.0	30,465.3	0.0	159,015.6
Suspended	14.0	4,667.0	705.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,224.2	100.0	0.0	0.0	0.0	0.0	0.0	737.6	106.3	7,554.0
Under Construction	1.0	7,840.3	349.4	13.0	0.0	3.0	0.0	0.0	44.0	1.3	0.0	0.0	2,021.9	5.7	0.0	36.0	0.0	0.0	0.0	760.0	0.0	11,075.6
Total	15,992.5	20,775.6	5,600.2	31.0	0.0	3.0	700.0	147.3	189.5	1.3	0.0	0.0	82,881.4	18,968.3	199.0	76.0	11.0	0.0	0.0	31,962.9	106.3	177,645.3

A significant shift in the distribution of unit types within the PJM footprint continues to develop as natural gas fired units and renewable resources enter the queue and coal fired steam units retire. As of March 31, 2021, of the 177,645.3 MW in the generation request queues in the status of active, suspended or under construction, 82,881.4 MW (46.7 percent) were solar projects, 31,962.9 MW (18.0 percent) were wind projects, 26,388.1 MW (14.9 percent) were natural gas fired projects (including combined cycle units, CTs, RICE units, and natural gas fired steam units), 19.273.6 MW (10.8 percent) were renewable hybrid projects (solar + storage, solar + wind and wind + storage units), and 76.0 MW (.04 percent) were coal fired steam projects.

As of March 31, 2021, there are 1,673.0 MW of coal fired steam units and 1,032.0 MW of natural gas units slated for deactivation between April 1, 2021, and December 31, 2024 (See Table 12-11). The ongoing replacement of coal fired steam units by natural gas units will continue to significantly affect future congestion, the role of firm and interruptible gas supply, and natural gas supply infrastructure.

Table 12-16 shows the total MW in the status of active, in service, under construction, suspended, or withdrawn for each queue since the beginning of the RTEP process and the total MW that had been included in each queue. All items in queues A-R are either in service or have been withdrawn. As of March 31, 2021, there are 177,645.3 MW in queues that are not yet in service or withdrawn, of which 4.3 percent are suspended, 6.2 percent are under construction and 89.5 percent have not begun construction.

Table 12-16 Queue totals by status (MW): March 31, 2021[31]

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	4,643.4	0.0	0.0	14,958.8	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	93.1	0.0	0.0	485.3	578.4
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	0.0	0.0	8,129.3	10,528.0
O Expired 31-Jul-05	0.0	1,890.2	0.0	0.0	5,466.8	7,357.0
P Expired 31-Jan-06	0.0	3,290.3	0.0	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	0.0	1,892.5	0.0	0.0	20,708.9	22,601.4
S Expired 31-Jul-07	70.0	3,543.5	0.0	0.0	12,396.5	16,010.0
T Expired 31-Jan-08	0.0	4,196.5	0.0	0.0	23,313.3	27,509.8
U1 Expired 30-Apr-08	0.0	218.9	0.0	0.0	7,937.8	8,156.7
U2 Expired 31-Jul-08	0.0	327.5	450.0	0.0	16,218.6	16,996.1
U3 Expired 31-Oct-08	100.0	333.0	0.0	0.0	2,535.6	2,968.6
U4 Expired 31-Jan-09	0.0	85.2	0.0	200.0	4,745.0	5,030.2
V1 Expired 30-Apr-09	0.0	197.9	0.0	0.0	2,572.8	2,770.7
V2 Expired 31-Jul-09	0.0	989.9	16.1	0.0	3,625.1	4,631.1
V3 Expired 31-Oct-09	0.0	912.0	220.0	0.0	3,822.7	4,954.7
V4 Expired 31-Jan-10	200.0	748.8	0.0	0.0	3,508.0	4,456.8
W1 Expired 30-Apr-10	0.0	567.4	0.0	0.0	5,139.5	5,706.9
W2 Expired 31-Jul-10	0.0	351.7	0.0	0.0	3,051.7	3,403.4
W3 Expired 31-Oct-10	22.7	508.7	0.0	0.0	8,673.2	9,204.6
W4 Expired 31-Jan-11	0.0	1,415.8	0.0	0.0	4,152.6	5,568.4
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	3,706.4	0.0	0.0	5,578.4	9,284.7
X3 Expired 31-Oct-11	0.0	89.2	20.0	0.0	7,665.9	7,775.1
X4 Expired 31-Jan-12	0.0	2,948.9	0.0	0.0	2,419.4	5,368.3
Y1 Expired 30-Apr-12	0.0	1,795.5	0.0	72.0	6,207.7	8,075.2
Y2 Expired 31-Oct-12	0.0	1,657.2	0.0	0.0	9,636.5	11,293.7
Y3 Expired 30-Apr-13	0.0	1,425.5	205.0	0.0	4,609.2	6,239.6
Z1 Expired 31-Oct-13	38.0	3,074.5	0.0	975.3	4,037.0	8,124.8
Z2 Expired 30-Apr-14	0.0	3,063.0	0.0	10.0	3,027.8	6,100.8
AA1 Expired 31-Oct-14	904.6	3,526.9	1,302.0	0.0	6,335.4	12,068.9
AA2 Expired 30-Apr-15	405.2	1,310.6	1,510.0	1,640.0	11,200.5	16,066.3
AB1 Expired 31-Oct-15	2,878.6	1,283.0	1,334.7	3,045.0	11,904.6	20,445.9
AB2 Expired 31-Mar-16	2,236.9	862.4	2,152.2	95.0	9,849.4	15,195.9
AC1 Expired 30-Sep-16	5,930.9	839.6	2,959.8	828.6	9,513.5	20,072.3
AC2 Expired 30-Apr-17	3,134.9	313.0	283.5	199.9	8,670.3	12,601.6
AD1 Expired 30-Sep-17	5,633.4	161.9	66.6	255.0	5,195.7	11,312.6
AD2 Expired 31-Mar-18	6,628.3	267.4	446.4	49.0	12,978.9	20,369.9
AE1 Expired 30-Sep-18	16,105.6	11.6	40.0	27.6	17,722.1	33,907.0
AE2 Expired 31-Mar-19	22,424.2	49.0	4.8	110.4	11,259.9	33,848.2
AF1 Expired 30-Sep-19	22,278.7	2.4	61.4	28.0	6,627.4	28,997.9
AF2 Expired 31-Mar-20	22,183.2	3.0	3.2	18.3	6,070.3	28,277.9
AG1 Expired 30-Sep-20	33,360.1	0.0	0.0	0.0	4,568.0	37,928.1
AG2 Expired 31-Mar-21	14,480.3	0.0	0.0	0.0	320.4	14,800.7
Total	159,015.6	73,369.0	11,075.6	7,554.0	417,726.4	668,740.7

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

Table 12-17 shows the projects with a status of active, suspended or under construction, by unit type, and control zone. As of March 31, 2021, 177,645.3 MW were in generation request queues for construction through 2029. Table 12-17 also shows the planned retirements for each zone.

Table 12-17 Queue totals for projects (active, suspended and under construction) by LDA, control zone and unit type (MW): March 31, 2021[32]

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	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total Queue Capacity	Planned Retirements
EMAAC	ACEC	793.0	7.6	230.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	739.0	93.0	0.0	0.0	0.0	0.0	0.0	3,441.6	0.0	5,304.2	0.0
	DPL	670.0	451.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,950.2	130.0	0.0	0.0	0.0	0.0	0.0	2,337.1	0.0	5,538.3	102.0
	JCPLC	669.8	35.0	0.0	0.0	0.0	0.0	0.0	30.0	0.0	0.0	0.0	0.0	269.6	180.0	0.0	0.0	0.0	0.0	0.0	4,269.2	0.0	5,453.5	0.0
	PECO	20.0	67.0	0.0	0.0	0.0	0.0	0.0	0.0	44.0	0.0	0.0	0.0	45.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	176.8	0.0
	PSEG	987.0	51.1	675.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	59.7	22.6	0.0	0.0	5.0	0.0	0.0	1,300.0	0.0	3,100.4	0.0
	REC	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	0.0	0.0
	EMAAC Total	3,139.8	611.7	905.0	0.0	0.0	0.0	0.0	30.0	44.0	0.0	0.0	0.0	3,064.3	425.6	0.0	0.0	5.0	0.0	0.0	11,347.9	0.0	19,573.2	102.0
SWMAAC	BGE	598.5	0.0	144.6	14.0	0.0	0.0	0.0	0.0	45.5	1.3	0.0	0.0	30.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	833.9	0.0
	PEPCO	1.0	0.0	57.3	4.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	78.9	562.5	0.0	0.0	6.0	0.0	0.0	0.0	0.0	709.7	667.0
	SWMAAC Total	599.5	0.0	201.9	18.0	0.0	0.0	0.0	0.0	45.5	1.3	0.0	0.0	108.9	562.5	0.0	0.0	6.0	0.0	0.0	0.0	0.0	1,543.6	667.0
WMAAC	MEC	405.2	75.0	13.5	7.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	888.1	182.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,571.4	51.0
	PE	530.8	248.0	585.5	0.0	0.0	3.0	0.0	0.0	0.0	0.0	0.0	0.0	3,790.5	697.2	0.0	0.0	0.0	0.0	0.0	210.2	0.0	6,065.1	0.0
	PPL	390.0	106.6	0.0	0.0	0.0	0.0	700.0	0.0	100.0	0.0	0.0	0.0	2,098.4	280.0	0.0	0.0	0.0	0.0	0.0	514.9	90.0	4,279.9	878.0
	WMAAC Total	1,326.0	429.6	599.0	7.5	0.0	3.0	700.0	0.0	100.0	0.0	0.0	0.0	6,777.0	1,159.2	0.0	0.0	0.0	0.0	0.0	725.1	90.0	11,916.4	929.0
Non-MAAC	AEP	2,903.8	6,015.0	719.0	0.0	0.0	0.0	0.0	51.0	0.0	0.0	0.0	0.0	26,162.1	7,725.7	0.0	76.0	0.0	0.0	0.0	4,754.6	0.0	48,407.1	132.0
	APS	422.8	3,584.7	112.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3,587.1	1,465.3	0.0	0.0	0.0	0.0	0.0	767.0	16.3	9,955.2	0.0
	ATSI	440.3	3,597.0	533.7	5.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4,090.3	270.9	0.0	0.0	0.0	0.0	0.0	816.1	0.0	9,753.7	0.0
	COMED	2,127.1	3,712.6	1,125.2	0.0	0.0	0.0	0.0	22.7	0.0	0.0	0.0	0.0	7,656.9	1,439.9	199.0	0.0	0.0	0.0	0.0	8,135.1	0.0	24,418.5	1,786.5
	DAY	175.0	1,150.0	43.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3,189.0	80.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4,637.5	0.0
	DUKE	72.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	533.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	606.1	0.0
	DLCO	55.0	0.0	222.9	0.0	0.0	0.0	0.0	43.6	0.0	0.0	0.0	0.0	58.9	37.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	417.9	0.0
	DOM	4,655.0	1,675.0	1,138.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	24,325.1	3,744.8	0.0	0.0	0.0	0.0	0.0	5,417.2	0.0	40,955.1	1,006.0
	EKPC	76.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3,208.0	2,057.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5,341.0	0.0
	OVEC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	120.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	120.0	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	0.0	0.0	0.0
	Non-MAAC Total	10,927.2	19,734.3	3,894.3	5.5	0.0	0.0	0.0	117.3	0.0	0.0	0.0	0.0	72,931.2	16,821.0	199.0	76.0	0.0	0.0	0.0	19,889.9	16.3	144,612.0	2,924.5
	Total	15,992.5	20,775.6	5,600.2	31.0	0.0	3.0	700.0	147.3	189.5	1.3	0.0	0.0	82,881.4	18,968.3	199.0	76.0	11.0	0.0	0.0	31,962.9	106.3	177,645.3	4,622.5

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 derated wind resources to 13 percent of nameplate capacity until there was operational data to support a different conclusion.[33] PJM derated solar resources to 38 percent of nameplate capacity. Effective June 1, 2017, PJM adjusted the derates of wind and solar resources. The capacity factor derates for wind resources are dependent on the wind farm locations and have an average derate of 16.2 percent. The capacity factor derates for solar resources are dependent on the solar installation type and have an average derate of 46.7 percent. Using the average derate factors, based on the derating of 31,962.9 MW of wind resources to 5,178.0 MW and 82,881.4 MW of solar resources to 38,705.6 MW, the 177,645.3 MW currently under construction, suspended or active in the queue would be reduced to 106,684.6 MW.[34]

32 This data includes only projects with a status of active, under construction, or suspended.
33 See PJM. "PJM Manual 14B: PJM Region Transmission Planning Process," Rev. 48 (Oct. 1, 2020).
34 Adjustments to totals for derates are applied to the solar and wind fuel types only. Additional derates may apply to hybrid units.

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, but the actual calculation of commercial probability factors is less than transparent.[35] 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 12-18 and Table 12-19.

Table 12-18 shows the milestone status when projects were withdrawn, for all withdrawn projects. Of the 3,088 projects withdrawn as of March 31, 2021, 1,546 (50.1 percent) were withdrawn before the system impact study was completed. Once a Construction Service Agreement (CSA) is executed, the financial obligation for any necessary transmission upgrades cannot be retracted. Of the 3,088 projects withdrawn, 595 (19.3 percent) were withdrawn after the completion of a Construction Service Agreement.

Table 12-18 Last milestone at time of withdrawal: January 1, 1997 through March 31, 2021

Milestone Completed	Projects Withdrawn	Percent	Average Days	Maximum Days
Never Started	519	16.8%	112	900
Feasibility Study	1,027	33.3%	267	1,633
System Impact Study	647	21.0%	709	3,248
Facilities Study	300	9.7%	1,133	4,107
Construction Service Agreement (CSA) or beyond	595	19.3%	1,357	7,864
Total	3,088	100.0%		

Average Time in Queue

Table 12-19 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 1,075 days, or 2.9 years, between entering a queue and going into service. For withdrawn projects, there is an average time of 623 days, or 1.7 years, between entering a queue and withdrawing.

Table 12-19 Project queue times by status (days): March 31, 2021[36]

Status	Average (Days)	Standard Deviation	Minimum	Maximum
Active	294	463	0	4,761
In-Service	1,075	785	0	5,306
Suspended	1,279	846	0	4,113
Under Construction	1,185	926	14	4,269
Withdrawn	623	736	0	7,864

Table 12-20 presents information on the time in the stages of the queue for those projects not yet in service or already withdrawn. Of the 1,927 projects in the queue as of March 31, 2021, 465 (24.1 percent) had a completed feasibility study and 386 (20.0 percent) had a completed construction service agreement.

Table 12-20 Project queue times by milestone (days): March 31, 2021

Milestone Reached	Number of Projects	Percent of Total Projects	Average Days	Maximum Days
Under Review	211	10.9%	0	0
Feasibility Study	465	24.1%	39	981
System Impact Study	836	43.4%	345	1,978
Facilities Study	29	1.5%	1,335	4,201
Construction Service Agreement (CSA) or beyond	386	20.0%	922	4,761
Total	1,927	100.0%		

Table 12-21 shows the time spent in the queue by fuel type, and year the project entered the queue, for projects that are in service. The time from when a project enters the queue to the time the project goes in service has generally been decreasing. For example, for a battery project entering the queue in 2015, there was an average of 1,082 days from the time it entered the queue until it went in service, compared to only 293 days when entering the queue in 2018, but the time increased to 504 days in 2019.

35 See PJM. "PJM Manual 14B: PJM Region Transmission Planning Process," Rev. 48 (Oct. 1, 2020).

36 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 12-21 Average time in queue (days) by fuel type and year submitted (In Service Projects): March 31, 2021[37]

Unit Type	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Battery	983	609	417	692	789	1,082	941	383	293	504		
CC	1,310	1,551	1,663	1,419	1,106	838	746	801	309	512		
CT - Natural Gas	1,131	804	953	1,021	734	901	1,192	657	564	206	319	
CT - Oil	717		259									
CT - Other	729	634	954	1,248	718	360						
Fuel Cell						827	643					
Hydro - Pumped Storage						1,402						
Hydro - Run of River			1,325	614	332		580	426	606			
Nuclear	885	866		1,234								
RICE - Natural Gas			1,702	1,053	1,332	798		250				
RICE - Oil						1,849						
RICE - Other	638	1,385	1,479	241	627	622	491		466			
Solar	1,701	1,313	969	1,014	1,003	1,416	988	658	643	508	296	
Solar + Storage									553			
Solar + Wind												
Steam - Coal	745		513	1,010	583	853	677	647				
Steam - Natural Gas				1,182		421	751					
Steam - Oil												
Steam - Other	256	838	643									
Wind	2,748	2,711	1,750	1,589	1,494	1,463	1,362	1,200	561			
Wind + Storage												

Completion Rates

The probability of a project going into service increases as each step of the planning process is completed.

Table 12-22 shows the historic completion rates (MW energy) by unit type for projects that have completed the system impact study (SIS), facilities study agreement (FSA) and construction service agreement (CSA) milestones as well as the historic completion rates for all projects including those withdrawn before reaching the SIS milestone. For each unit type, the total MW in service was divided by the total energy MW entered in the queue. To calculate the completion rates for projects that reached the individual milestones, only those projects that reached a final status of withdrawn or in service were evaluated. For example, if a project was withdrawn after the completion of its SIS, but before the completion of the FSA, the totals would be included in the calculation of the SIS completion rate, but not in the calculation of the FSA or CSA completion rates. Similarly, if a project was withdrawn after the completion of its FSA, but before the completion of the CSA, the totals would be included in the calculation of the SIS and FSA completion rates, but not in the calculation of the CSA completion rate. The completion rates show that of all battery projects to ever enter the queue and complete the system impact study stage, 15.3 percent of the queued MW have gone into service. The completion rate for battery projects increases to 36.1 percent when battery projects complete the facility study agreement and further increases to 43.1 percent when battery projects complete the construction service agreement. Of all battery projects to enter the queue, only 1.2 percent of the queued MW have gone into service.

37 A blank cell in this table means that no project of that fuel type, that was submitted to the queue in that year, subsequently went in service.

Table 12-22 Historic completion rates (MW energy) by unit type for projects with a completed SIS, FSA and CSA: March 31, 2021

Unit Type	Completion Rate (SIS)	Completion Rate (FSA)	Completion Rate (CSA)	Completion Rate (ALL)
Battery	15.3%	36.1%	43.1%	1.2%
CC	32.0%	49.6%	77.4%	13.8%
CT - Natural Gas	66.7%	82.2%	85.8%	42.7%
CT - Oil	35.6%	60.2%	90.8%	25.4%
CT - Other	12.3%	18.6%	29.5%	10.7%
Fuel Cell	30.6%	31.6%	31.6%	43.6%
Hydro - Pumped Storage	100.0%	100.0%	100.0%	24.5%
Hydro - Run of River	43.2%	61.3%	68.9%	20.8%
Nuclear	35.2%	42.1%	51.3%	28.6%
RICE - Natural Gas	30.7%	42.9%	47.6%	26.4%
RICE - Oil	34.0%	59.7%	59.7%	26.2%
RICE - Other	89.0%	91.4%	92.0%	78.1%
Solar	15.4%	34.9%	44.4%	2.6%
Solar + Storage	0.1%	100.0%	100.0%	0.0%
Solar + Wind	0.0%	0.0%	0.0%	0.0%
Steam - Coal	13.6%	25.4%	37.5%	6.2%
Steam - Natural Gas	91.1%	91.1%	91.1%	90.0%
Steam - Oil	0.0%	0.0%	0.0%	0.0%
Steam - Other	30.4%	39.9%	47.8%	27.4%
Wind	0.2%	100.0%	100.0%	0.0%
Wind + Storage	0.0%	0.0%	0.0%	0.0%

On March 31, 2021, 177,645.3 MW were in generation request queues in the status of active, under construction or suspended. Of the total 177,645.3 MW in the queue, 118,959.5 MW (67.0 percent) have reached at least the SIS milestone and 58,685.8 MW (23.0 percent) have not received a completed SIS. Based on historical completion rates, (applying the unit type specific completion rates for those projects that have reached the SIS, FSA or CSA milestone, and using the overall completion rates for those projects that have not yet reached the SIS milestone), 37,491.5 MW of new generation in the queue are expected to go into service.

Table 12-23 shows the percent of all project MW, by unit type, to go in service by year submitted to the queue. Of all battery projects that entered the queue in 2010, 65.5 percent reached the status of in service by March 31, 2021. Of all battery projects that entered the queue in 2016, only 1.3 percent have reached the status of in service as of March 31, 2021.

Table 12-23 Percent of all projects (MW energy) to go in service by unit type and year submitted to the queue: March 31, 2021

Unit Type	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Battery	65.5%	8.3%	15.1%	43.9%	21.5%	7.7%	1.3%	4.1%	0.3%	0.0%	0.0%	0.0%
CC	14.6%	24.5%	30.8%	35.6%	43.7%	3.7%	2.2%	2.5%	1.2%	0.5%	NA	NA
CT - Natural Gas	100.0%	98.3%	89.7%	23.5%	32.0%	0.2%	8.2%	16.5%	3.6%	0.0%	0.5%	0.0%
CT - Oil	100.0%	NA	1.2%	0.0%	0.0%	NA	NA	NA	0.0%	0.0%	0.0%	NA
CT - Other	28.8%	27.1%	36.1%	100.0%	0.0%	100.0%	NA	0.0%	NA	NA	NA	NA
Fuel Cell	NA	NA	NA	NA	NA	67.4%	12.5%	0.0%	NA	0.0%	NA	NA
Hydro - Pumped Storage	NA	NA	NA	NA	NA	100.0%	NA	NA	0.0%	0.0%	NA	NA
Hydro - Run of River	0.0%	0.0%	57.6%	49.6%	11.2%	NA	100.0%	26.8%	100.0%	0.0%	0.0%	0.0%
Nuclear	15.5%	1.6%	0.0%	100.0%	NA	NA	0.0%	71.6%	0.0%	NA	0.0%	NA
RICE - Natural Gas	NA	NA	100.0%	66.7%	5.4%	6.2%	0.0%	5.4%	NA	NA	NA	NA
RICE - Oil	0.0%	0.0%	NA	NA	NA	30.8%	NA	NA	NA	NA	NA	NA
RICE - Other	100.0%	100.0%	100.0%	100.0%	79.7%	25.5%	2.8%	0.0%	100.0%	NA	NA	NA
Solar	10.7%	7.1%	16.9%	24.4%	30.7%	17.8%	5.3%	0.4%	0.1%	0.0%	0.0%	0.0%
Solar + Storage	NA	NA	NA	NA	NA	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Solar + Wind	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	0.0%	NA
Steam - Coal	100.0%	0.0%	1.4%	68.4%	1.2%	23.4%	37.5%	100.0%	0.0%	0.0%	NA	NA
Steam - Natural Gas	NA	NA	NA	100.0%	0.0%	100.0%	100.0%	100.0%	NA	NA	0.0%	NA
Steam - Oil	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Steam - Other	0.5%	61.2%	16.6%	0.0%	0.0%	NA	NA	NA	NA	NA	NA	NA
WInd	6.1%	3.4%	2.5%	5.8%	20.7%	12.5%	12.3%	2.6%	0.0%	0.0%	0.0%	0.0%
Wind + Storage	NA	NA	NA	NA	NA	NA	0.0%	0.0%	NA	NA	NA	NA
All	10.4%	18.9%	26.5%	32.1%	34.3%	6.5%	2.8%	1.5%	0.4%	0.0%	0.0%	0.0%

Queue Analysis by Fuel Group

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 12-24 shows the number of projects that entered the queue by year and by fuel group. The fuel groups are nuclear units, renewable units (including solar, hydro, biomass, renewable hybrid and wind) and traditional units (all other fuels). The number of queue entries has increased during the past several years, primarily by renewable projects. Of the 3,330 projects entered from January 2015 through March 2021, 2,515 projects (75.5 percent) were renewable. Of the 140 projects entered in the first three months of 2021, 117 projects (83.6 percent) were renewable.

Table 12-24 Number of projects entered in the queue: March 31, 2021

	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	102	111	216
2009	10	107	56	173
2010	5	370	66	441
2011	6	264	85	355
2012	2	59	98	159
2013	1	54	99	154
2014	0	100	92	192
2015	0	134	175	309
2016	2	298	99	399
2017	2	293	60	355
2018	1	343	96	440
2019	0	544	153	697
2020	2	786	202	990
2021	0	117	23	140
Total	72	3,858	2,052	5,982

As of March 31, 2021, renewable projects make up 79.1 percent of all projects in the queue and those projects account for 76.0 percent of the nameplate MW currently active, suspended or under construction in the queue as of March 31, 2021 (Table 12-25).

Table 12-25 Queue details by fuel group: March 31, 2021

Fuel Group	Number of Projects	Percent of Projects	MW	Percent MW
Nuclear	6	0.3%	189.5	0.1%
Renewable	1,525	79.1%	134,968.2	76.0%
Traditional	396	20.6%	42,487.6	23.9%
Total	1,927	100.0%	177,645.3	100.0%

Historical completion rates for renewable projects may not be an accurate predictor of completion rates for current renewable projects. The outcomes for current projects will provide additional information and improve the ability to assess the likely future generation mix based on the type of projects in the queue.

While renewables currently make up the majority of both projects and nameplate MW in the queue, historical completion rates and derating factors must be accounted for when evaluating the share of capacity resources that are likely to be contributed by renewables (Table 12-22). Table 12-26 shows the total MW of all projects in the queue as of March 31, 2021, in the status of active, suspended and under construction, by unit type. Table 12-26 also shows the total MW for each fuel type adjusted based on current historical completion rates and for the average solar and wind derates. Of the 20,775.6 MW of combined cycle projects in the queue, 13,660.7 MW (65.8 percent) are expected to go in service based on historical completion rates as of March 31, 2021. Of the 134,968.2 MW of renewable projects in the queue, only 18,847.6 MW (14.0 percent) are expected to go in service based on historical completion rates. Of the 134,968.2 MW of renewable projects in the queue, only 7,506.5 MW (5.6 percent) of capacity resources are expected to go into service, based on both historical completion rates and average derate factors for wind and solar.

Table 12-26 Queue totals for projects (active, suspended and under construction) by unit type adjusted based on current historical completion rates and average solar and wind derates (MW): March 31, 2021[38]

Unit Type	MW in Queue	Completion Rate Adjusted MW in Queue	Completion Rate and Derate Adjusted MW in Queue
Battery	15,992.5	1,124.1	1,124.1
CC	20,775.6	13,660.7	13,660.7
CT - Natural Gas	5,600.2	3,732.5	3,732.5
CT - Oil	31.0	18.2	18.2
CT - Other	0.0	0.0	0.0
Fuel Cell	3.0	0.9	0.9
Hydro - Pumped Storage	700.0	700.0	700.0
Hydro - Run of River	147.3	61.5	61.5
Nuclear	189.5	71.9	71.9
RICE - Natural Gas	1.3	0.6	0.6
RICE - Oil	0.0	0.0	0.0
RICE - Other	0.0	0.0	0.0
Solar	82,881.4	11,656.1	5,443.4
Solar + Storage	18,968.3	309.1	309.1
Solar + Wind	199.0	0.0	0.0
Steam - Coal	76.0	25.9	25.9
Steam - Natural Gas	11.0	10.0	10.0
Steam - Oil	0.0	0.0	0.0
Steam - Other	0.0	0.0	0.0
Wind	31,962.9	6,119.8	991.4
Wind + Storage	106.3	0.0	0.0
Total	177,645.3	37,491.5	26,150.4

Queue Analysis by Unit Type and Project Classification

Table 12-27 shows the current status of all generation queue projects by unit type and project classification from January 1, 1997, through March 31, 2021. As of March 31, 2021, 5,982 projects, representing 668,740.7 MW, have entered the queue process since its inception. Of those, 967 projects, representing 73,369.0 MW, went into service. Of the projects that entered the queue process, 3,088 projects, representing 417,726.4 MW (62.5 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 4,821 projects have been classified as new generation and 1,161 projects have been classified as upgrades. Natural gas, wind, solar and renewable hybrid projects (including solar + storage, solar + wind and wind + storage) have accounted for 4,779 projects (79.9 percent) of all 5,982 generation queue projects to enter the queue since January 1, 1997.

38 Adjustments to totals for derates are applied to the solar and wind fuel types only. Additional derates may apply to hybrid units.

Table 12-27 Status of all generation queue projects: January 1, 1997 through March 31, 2021

		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	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
In Service	New Generation	22	62	48	10	25	3	0	10	2	10	0	55	166	1	0	8	5	0	4	94	0	525
	Upgrade	7	102	108	15	5	0	3	19	42	9	2	16	30	0	0	55	10	0	8	11	0	442
Under Construction	New Generation	1	7	3	0	0	0	0	0	0	1	0	0	28	2	0	0	0	0	0	4	0	46
	Upgrade	0	10	15	8	0	1	0	0	1	0	0	0	11	1	0	1	0	0	0	1	0	49
Suspended	New Generation	3	5	1	0	0	0	0	0	0	0	0	0	24	1	0	0	0	0	0	6	1	41
	Upgrade	0	3	1	0	0	0	0	0	0	0	0	0	5	0	0	0	0	0	0	0	1	10
Withdrawn	New Generation	177	431	28	9	81	26	2	42	9	28	12	16	1,325	63	0	55	1	0	34	446	0	2,785
	Upgrade	38	96	16	13	13	2	0	5	13	0	2	3	53	1	0	15	0	0	2	31	0	303
Active	New Generation	174	9	8	1	0	0	2	6	0	0	0	0	936	198	1	0	1	0	0	88	0	1,424
	Upgrade	93	16	27	2	1	0	0	2	5	0	0	0	162	27	0	3	2	0	0	16	1	357
Total Projects	New Generation	377	514	88	20	106	29	4	58	11	39	12	71	2,479	265	1	63	7	0	38	638	1	4,821
	Upgrade	138	227	167	38	19	3	3	26	61	9	4	19	261	29	0	74	12	0	10	59	2	1,161

Table 12-28 shows the totals in Table 12-27 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, 73.1 percent of all hydro run of river projects classified as upgrades are currently in service in PJM, 19.2 percent of hydro run of river upgrades were withdrawn and 7.7 percent of hydro run of river upgrades are active in the queue.

Table 12-28 Status of all generation queue projects as a percent of total projects by classification: January 1, 1997 through March 31, 2021

		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	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
In Service	New Generation	5.8%	12.1%	54.5%	50.0%	23.6%	10.3%	0.0%	17.2%	18.2%	25.6%	0.0%	77.5%	6.7%	0.4%	0.0%	12.7%	71.4%	0.0%	10.5%	14.7%	0.0%	10.9%
	Upgrade	5.1%	44.9%	64.7%	39.5%	26.3%	0.0%	100.0%	73.1%	68.9%	100.0%	50.0%	84.2%	11.5%	0.0%	0.0%	74.3%	83.3%	0.0%	80.0%	18.6%	0.0%	38.1%
Under Construction	New Generation	0.3%	1.4%	3.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	2.6%	0.0%	0.0%	1.1%	0.8%	0.0%	0.0%	0.0%	0.0%	0.0%	0.6%	0.0%	1.0%
	Upgrade	0.0%	4.4%	9.0%	21.1%	0.0%	33.3%	0.0%	0.0%	1.6%	0.0%	0.0%	0.0%	4.2%	3.4%	0.0%	1.4%	0.0%	0.0%	0.0%	1.7%	0.0%	4.2%
Suspended	New Generation	0.8%	1.0%	1.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.0%	0.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.9%	100.0%	0.9%
	Upgrade	0.0%	1.3%	0.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.9%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	50.0%	0.9%
Withdrawn	New Generation	46.9%	83.9%	31.8%	45.0%	76.4%	89.7%	50.0%	72.4%	81.8%	71.8%	100.0%	22.5%	53.4%	23.8%	0.0%	87.3%	14.3%	0.0%	89.5%	69.9%	0.0%	57.8%
	Upgrade	27.5%	42.3%	9.6%	34.2%	68.4%	66.7%	0.0%	19.2%	21.3%	0.0%	50.0%	15.8%	20.3%	3.4%	0.0%	20.3%	0.0%	0.0%	20.0%	52.5%	0.0%	26.1%
Active	New Generation	46.2%	1.8%	9.1%	5.0%	0.0%	0.0%	50.0%	10.3%	0.0%	0.0%	0.0%	0.0%	37.8%	74.7%	100.0%	0.0%	14.3%	0.0%	0.0%	13.8%	0.0%	29.5%
	Upgrade	67.4%	7.0%	16.2%	5.3%	5.3%	0.0%	0.0%	7.7%	8.2%	0.0%	0.0%	0.0%	62.1%	93.1%	0.0%	4.1%	16.7%	0.0%	0.0%	27.1%	50.0%	30.7%

Table 12-29 shows the total MW of projects in the PJM generation queue by unit type and project classification. For example, the 446 new generation wind projects that have been withdrawn from the queue as of March 31, 2021, (as shown in Table 12-27) constitute 77,442.0 MW. The 431 new generation combined cycle projects that have been withdrawn in the same time period constitute 215,469.7 MW.

Table 12-29 Status of all generation (MW) in the generation queue: January 1, 1997 through March 31, 2021

		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	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
In Service	New Generation	223.4	33,703.0	6,664.4	676.5	151.3	1.9	0.0	371.5	1,639.0	156.4	0.0	440.1	2,464.5	1.1	0.0	1,343.0	723.0	0.0	60.9	9,919.6	0.0	58,539.6
	Upgrade	44.4	6,591.8	2,725.5	127.8	12.3	0.0	390.0	387.6	2,310.8	17.3	27.3	50.7	46.3	0.0	0.0	965.5	225.5	0.0	667.8	238.7	0.0	14,829.3
Under Construction	New Generation	1.0	6,596.9	259.4	0.0	0.0	0.0	0.0	0.0	0.0	1.3	0.0	0.0	1,768.7	2.6	0.0	0.0	0.0	0.0	0.0	760.0	0.0	9,389.9
	Upgrade	0.0	1,243.4	90.0	13.0	0.0	3.0	0.0	0.0	44.0	0.0	0.0	0.0	253.2	3.2	0.0	36.0	0.0	0.0	0.0	0.0	0.0	1,685.8
Suspended	New Generation	14.0	4,136.0	675.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,155.6	100.0	0.0	0.0	0.0	0.0	0.0	737.6	90.0	6,908.1
	Upgrade	0.0	531.0	30.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	68.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	16.3	645.9
Withdrawn	New Generation	4,186.5	215,469.7	4,281.7	1,721.0	1,244.2	5.5	500.0	2,043.8	8,161.0	479.9	63.9	88.6	40,712.9	7,805.0	0.0	33,511.6	27.0	0.0	1,050.9	77,441.9	0.0	398,795.0
	Upgrade	841.3	11,590.4	670.6	589.0	72.5	0.9	0.0	105.1	966.0	0.0	13.0	10.0	1,533.4	3.7	0.0	885.0	0.0	0.0	37.1	1,613.4	0.0	18,931.4
Active	New Generation	13,055.5	6,483.0	2,883.6	14.0	0.0	0.0	700.0	66.3	0.0	0.0	0.0	0.0	73,308.2	17,735.6	199.0	0.0	5.0	0.0	0.0	28,875.3	0.0	143,325.4
	Upgrade	2,922.0	1,785.3	1,662.2	4.0	0.0	0.0	0.0	81.0	145.5	0.0	0.0	0.0	6,327.2	1,127.0	0.0	40.0	6.0	0.0	0.0	1,590.1	0.0	15,690.3
Total Projects	New Generation	17,480.3	266,388.6	14,764.1	2,411.5	1,395.6	7.4	1,200.0	2,481.5	9,800.0	637.6	63.9	528.7	119,409.9	25,644.2	199.0	34,854.6	755.0	0.0	1,111.8	117,734.4	90.0	616,958.0
	Upgrade	3,807.7	21,741.9	5,178.3	733.8	84.8	3.9	390.0	573.7	3,466.3	17.3	40.3	60.7	8,228.7	1,133.9	0.0	1,926.5	231.5	0.0	704.9	3,442.2	16.3	51,782.7

Table 12-30 shows the MW totals in Table 12-29 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, 65.8 percent of wind project MW classified as new generation have been withdrawn from the queue between January 1, 1997, and March 31, 2021.

Table 12-30 Status of all generation queue projects as percent of total MW in project classification: January 1, 1997 through March 31, 2021

		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	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
In Service	New Generation	1.3%	12.7%	45.1%	28.1%	10.8%	26.2%	0.0%	15.0%	16.7%	24.5%	0.0%	83.2%	2.1%	0.0%	0.0%	3.9%	95.8%	0.0%	5.5%	8.4%	0.0%	9.5%
	Upgrade	1.2%	30.3%	52.6%	17.4%	14.5%	0.0%	100.0%	67.6%	66.7%	100.0%	67.7%	83.5%	0.6%	0.0%	0.0%	50.1%	97.4%	0.0%	94.7%	6.9%	0.0%	28.6%
Under Construction	New Generation	0.0%	2.5%	1.8%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%	0.0%	0.0%	1.5%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.6%	0.0%	1.5%
	Upgrade	0.0%	5.7%	1.7%	1.8%	0.0%	76.0%	0.0%	0.0%	1.3%	0.0%	0.0%	0.0%	3.1%	0.3%	0.0%	1.9%	0.0%	0.0%	0.0%	0.0%	0.0%	3.3%
Suspended	New Generation	0.1%	1.6%	4.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.0%	0.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.6%	100.0%	1.1%
	Upgrade	0.0%	2.4%	0.6%	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%	0.0%	0.0%	0.0%	100.0%	1.2%
Withdrawn	New Generation	23.9%	80.9%	29.0%	71.4%	89.2%	73.8%	41.7%	82.4%	83.3%	75.3%	100.0%	16.8%	34.1%	30.4%	0.0%	96.1%	3.6%	0.0%	94.5%	65.8%	0.0%	64.6%
	Upgrade	22.1%	53.3%	13.0%	80.3%	85.5%	24.0%	0.0%	18.3%	27.9%	0.0%	32.3%	16.5%	18.6%	0.3%	0.0%	45.9%	0.0%	0.0%	5.3%	46.9%	0.0%	36.6%
Active	New Generation	74.7%	2.4%	19.5%	0.6%	0.0%	0.0%	58.3%	2.7%	0.0%	0.0%	0.0%	0.0%	61.4%	69.2%	100.0%	0.0%	0.7%	0.0%	0.0%	24.5%	0.0%	23.2%
	Upgrade	76.7%	8.2%	32.1%	0.5%	0.0%	0.0%	0.0%	14.1%	4.2%	0.0%	0.0%	0.0%	76.9%	99.4%	0.0%	2.1%	2.6%	0.0%	0.0%	46.2%	0.0%	30.3%

Table 12-31 shows the project MW that entered the PJM generation queue by unit type and year of entry. Since 2016, 77.9 percent of all new projects entering the generation queue have been combined cycle (15.1 percent), wind (17.6 percent) or solar projects (45.2 percent). Prior to 2015, no renewable hybrid units (solar + storage, solar + wind and wind + storage) entered the queue. In the time period from January 1, 2015 through March 31, 2021, 27,081.4 MW have entered the queue.

Table 12-31 Queue project MW by unit type and queue entry year: January 1, 1997 through March 31, 2021

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	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	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	0.0	0.0	6.0	0.0	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	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	0.0	0.0	47.0	0.0	0.0	525.0	115.4	0.0	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	0.0	0.0	37.0	2.5	0.0	0.0	95.6	0.0	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	0.0	0.0	1,244.6	10.0	0.0	0.0	252.9	0.0	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	0.0	0.0	1,895.0	0.0	0.0	0.0	790.9	0.0	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	0.0	0.0	522.0	0.0	0.0	165.0	997.0	0.0	4,122.7
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	0.0	0.0	1,187.0	0.0	0.0	0.0	1,614.7	0.0	8,488.1
2005	0.0	5,824.6	961.0	281.0	51.4	0.0	340.0	174.2	242.0	21.5	0.0	65.1	0.0	0.0	0.0	6,360.0	0.0	0.0	24.0	6,020.0	0.0	20,364.9
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	0.0	0.0	9,586.0	0.0	0.0	258.5	7,650.7	0.0	29,964.2
2007	0.0	13,944.6	941.2	215.9	149.5	0.0	16.0	161.6	368.0	0.0	0.0	56.5	3.3	0.0	0.0	9,078.0	190.0	0.0	50.5	18,525.6	0.0	43,700.6
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	0.0	0.0	1,198.0	0.0	0.0	192.3	11,016.1	0.0	41,723.7
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	0.0	0.0	1,273.0	5.5	0.0	148.0	6,672.6	0.0	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	3,672.6	0.0	0.0	64.0	0.0	0.0	173.5	9,803.4	0.0	23,891.3
2011	24.1	19,744.0	29.5	0.0	174.6	0.0	0.0	30.0	182.0	0.0	14.0	75.3	2,014.0	0.0	0.0	357.0	0.0	0.0	49.0	5,576.4	0.0	28,269.9
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	284.6	0.0	0.0	1,837.0	0.0	0.0	143.1	1,529.8	0.0	22,746.8
2013	217.4	10,493.1	1,201.8	5.0	11.2	0.0	0.0	89.4	102.0	59.7	0.0	1.6	231.7	0.0	0.0	158.0	40.0	0.0	44.7	1,407.9	0.0	14,063.4
2014	246.9	11,704.5	1,532.5	401.0	7.7	0.0	0.0	60.5	0.0	48.0	0.0	17.7	1,590.0	0.0	0.0	1,730.5	27.0	0.0	43.1	1,689.7	0.0	19,099.0
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	2,922.9	2.0	0.0	47.0	606.5	0.0	0.0	2,160.6	0.0	35,553.0
2016	111.1	18,802.5	1,392.0	0.0	0.0	3.4	0.0	12.5	50.3	23.5	0.0	38.9	11,665.7	85.6	0.0	80.0	77.0	0.0	0.0	3,448.7	16.3	35,807.4
2017	24.6	5,477.6	701.0	0.0	4.1	2.7	0.0	20.5	39.1	97.1	0.0	33.8	13,656.7	424.9	0.0	14.0	17.0	0.0	0.0	5,137.0	90.0	25,740.2
2018	1,513.7	11,080.1	2,647.4	14.0	0.0	0.0	700.0	2.4	28.1	0.0	0.0	0.8	19,734.1	4,573.9	0.0	49.0	0.0	0.0	0.0	17,710.4	0.0	58,053.8
2019	5,843.2	3,332.5	1,572.1	13.0	0.0	3.0	500.0	99.0	0.0	0.0	0.0	0.0	27,416.3	9,596.1	0.0	11.0	0.0	0.0	0.0	11,585.4	0.0	59,971.6
2020	11,173.9	0.0	552.6	4.0	0.0	0.0	0.0	80.2	100.0	0.0	0.0	0.0	38,850.0	9,229.9	199.0	0.0	11.0	0.0	0.0	6,915.9	0.0	67,116.5
2021	1,216.2	0.0	700.0	0.0	0.0	0.0	0.0	35.3	0.0	0.0	0.0	0.0	4,893.8	2,865.7	0.0	0.0	0.0	0.0	0.0	460.0	0.0	10,170.9
Total	21,288.1	288,130.5	19,942.4	3,145.3	1,480.3	11.3	1,590.0	3,055.2	13,266.3	654.9	104.2	589.4	127,638.5	26,778.1	199.0	36,781.1	986.5	0.0	1,816.7	121,176.6	106.3	668,740.7

Combined Cycle Project Analysis

Table 12-32 shows the status of all combined cycle projects by number of projects that entered PJM generation queues from January 1, 1997, through March 31, 2021, by zone. Of the 50 combined cycle projects classified as new generation or upgrade currently active, suspended or under construction in the PJM generation queue, 24 projects (24.0 percent) are located in the AEP Zone.

Table 12-32 Status of all combined cycle queue projects by zone (number of projects): January 1, 1997 through March 31, 2021

		Number of Projects																					
Project Status	Project Classification	ACEC	AEP	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
In Service	New Generation	1	4	2	3	2	1	0	2	0	7	2	0	7	4	0	5	2	4	10	6	0	62
	Upgrade	3	12	7	5	0	5	0	0	0	16	5	0	6	3	0	11	4	4	7	14	0	102
Under Construction	New Generation	0	3	1	1	0	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	7
	Upgrade	0	4	2	0	0	0	0	0	0	0	0	0	0	1	0	1	0	0	1	1	0	10
Suspended	New Generation	0	0	2	2	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	5
	Upgrade	0	0	1	0	0	0	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	3
Withdrawn	New Generation	23	19	45	13	8	14	0	1	2	18	17	3	26	25	0	43	40	34	42	56	2	431
	Upgrade	7	7	9	3	0	4	0	1	0	11	4	0	7	7	0	3	5	5	8	15	0	96
Active	New Generation	0	3	1	0	0	3	0	0	0	1	0	0	0	0	0	0	1	0	0	0	0	9
	Upgrade	1	2	4	1	0	2	0	0	0	1	0	0	0	0	0	1	2	0	2	0	0	16
Total Projects	New Generation	24	29	51	19	10	20	1	3	2	26	19	3	33	29	0	48	43	38	52	62	2	514
	Upgrade	11	25	23	9	0	11	0	1	0	28	10	0	14	11	0	16	11	9	18	30	0	227

Table 12-33 shows the status of all combined cycle projects by MW that entered PJM generation queues from January 1, 1997, through March 31, 2021, by zone. Of the 20,775.6 MW of combined cycle projects classified as new generation or upgrade currently active, suspended or under construction in the PJM generation queue, 6,015.0 MW (29.0 percent) are located in the AEP Zone.

Table 12-33 Status of all combined cycle queue projects by zone (MW): January 1, 1997 through March 31, 2021

		Project MW																					
Project Status	Project Classification	ACEC	AEP	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
In Service	New Generation	650.0	3,032.0	1,455.0	2,599.0	140.0	600.0	0.0	533.0	0.0	5,828.6	319.2	0.0	1,665.8	2,557.0	0.0	2,665.0	1,900.0	1,560.0	5,750.0	2,448.5	0.0	33,703.0
	Upgrade	229.0	384.0	790.0	344.0	0.0	633.6	0.0	0.0	0.0	978.0	102.0	0.0	110.0	83.9	0.0	1,008.5	142.3	228.6	712.0	845.9	0.0	6,591.8
Under Construction	New Generation	0.0	2,579.0	515.0	1,152.0	0.0	2,350.9	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	6,596.9
	Upgrade	0.0	916.0	149.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	75.0	0.0	0.0	0.0	0.0	51.6	51.1	0.0	1,243.4
Suspended	New Generation	0.0	0.0	1,091.0	1,895.0	0.0	0.0	1,150.0	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	4,136.0
	Upgrade	0.0	0.0	45.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	451.0	0.0	35.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	531.0
Withdrawn	New Generation	8,542.4	12,509.5	21,832.1	8,641.0	3,122.1	10,142.0	0.0	134.5	665.0	12,321.0	5,436.4	991.8	13,562.6	13,001.0	0.0	23,340.0	15,951.0	21,308.2	18,917.7	25,044.6	6.9	215,469.7
	Upgrade	149.4	711.0	874.0	86.0	0.0	1,735.0	0.0	36.0	0.0	780.4	668.0	0.0	378.0	1,742.0	0.0	240.0	1,040.6	229.1	703.0	2,217.9	0.0	11,590.4
Active	New Generation	0.0	2,200.0	1,270.0	0.0	0.0	1,250.0	0.0	0.0	0.0	1,600.0	0.0	0.0	0.0	0.0	0.0	0.0	163.0	0.0	0.0	0.0	0.0	6,483.0
	Upgrade	7.6	320.0	514.0	550.0	0.0	111.7	0.0	0.0	0.0	75.0	0.0	0.0	0.0	0.0	0.0	67.0	85.0	0.0	55.0	0.0	0.0	1,785.3
Total Projects	New Generation	9,192.4	20,320.5	26,163.1	14,287.0	3,262.1	14,342.9	1,150.0	667.5	665.0	19,749.6	5,755.6	991.8	15,228.4	15,558.0	0.0	26,005.0	18,014.0	22,868.2	24,667.7	27,493.1	6.9	266,388.6
	Upgrade	386.0	2,331.0	2,372.7	980.0	0.0	2,480.3	0.0	36.0	0.0	1,833.4	1,221.0	0.0	523.0	1,900.9	0.0	1,315.5	1,267.9	457.7	1,521.6	3,114.9	0.0	21,741.9

Combustion Turbine - Natural Gas Project Analysis

Table 12-34 shows the status of all combustion turbine natural gas projects by number of projects that entered PJM generation queues from January 1, 1997, through March 31, 2021, by zone. Of the 55 combustion turbine natural gas projects classified as new generation or upgrade currently active, suspended or under construction in the PJM generation queue, 14 projects (25.5 percent) are located in the COMED Zone.

Table 12-34 Status of all combustion turbine - natural gas generation queue projects by zone (number of projects): January 1, 1997 through March 31, 2021

		Number of Projects																					
Project Status	Project Classification	ACEC	AEP	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
In Service	New Generation	5	0	6	0	3	0	0	0	0	3	7	0	2	1	0	2	4	2	4	9	0	48
	Upgrade	4	9	7	2	0	12	5	0	0	28	7	0	4	1	0	4	4	3	4	14	0	108
Under Construction	New Generation	0	0	0	0	0	1	0	0	2	0	0	0	0	0	0	0	0	0	0	0	0	3
	Upgrade	0	0	1	2	0	3	0	0	0	0	0	0	1	4	0	0	4	0	0	0	0	15
Suspended	New Generation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	1
	Upgrade	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Withdrawn	New Generation	1	6	0	0	1	1	1	0	0	4	0	1	1	0	0	1	5	0	1	5	0	28
	Upgrade	2	2	1	1	0	2	2	0	1	3	0	0	0	1	0	0	1	0	0	0	0	16
Active	New Generation	1	1	0	0	1	1	0	0	0	2	0	0	0	0	0	0	2	0	0	0	0	8
	Upgrade	1	1	2	5	0	9	2	0	1	0	0	0	0	0	0	0	1	5	0	0	0	27
Total Projects	New Generation	7	7	6	0	5	3	1	0	2	9	7	1	3	1	0	3	11	2	5	15	0	88
	Upgrade	7	12	12	10	0	26	9	0	2	31	7	0	5	6	0	4	10	8	4	14	0	167

Table 12-35 shows the status of all combustion turbine natural gas projects by MW that entered PJM generation queues from January 1, 1997, through March 31, 2021, by zone. Of the 5,600.2 MW of combustion turbine natural gas projects classified as new generation or upgrade currently active, suspended or under construction in the PJM generation queue, 1,138.0 MW (20.3 percent) are located in the Dominion Zone.

Table 12-35 Status of all combustion turbine - natural gas queue projects by zone (MW): January 1, 1997 through March 31, 2021

		Project MW																					
Project Status	Project Classification	ACEC	AEP	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
In Service	New Generation	360.7	0.0	1,176.0	0.0	23.0	0.0	0.0	0.0	0.0	1,081.0	1,491.0	0.0	520.0	10.0	0.0	559.0	361.9	5.0	150.9	925.9	0.0	6,664.4
	Upgrade	43.7	208.0	187.7	40.0	0.0	371.0	60.0	0.0	0.0	925.7	86.0	0.0	200.0	34.1	0.0	42.0	28.0	32.0	252.3	215.0	0.0	2,725.5
Under Construction	New Generation	0.0	0.0	0.0	0.0	0.0	40.0	0.0	0.0	219.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	259.4
	Upgrade	0.0	0.0	12.0	5.0	0.0	47.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	13.5	0.0	0.0	12.5	0.0	0.0	0.0	0.0	90.0
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	0.0	0.0	0.0	0.0	675.0	0.0	675.0
	Upgrade	0.0	0.0	30.0	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	30.0
Withdrawn	New Generation	7.5	1,519.0	0.0	0.0	9.0	10.0	104.0	0.0	0.0	1,069.8	0.0	73.0	2.1	0.0	0.0	0.5	326.8	0.0	19.9	1,140.1	0.0	4,281.7
	Upgrade	165.5	57.1	4.0	25.0	0.0	23.0	104.0	0.0	0.0	57.0	0.0	0.0	0.0	0.0	0.0	0.0	235.0	0.0	0.0	0.0	0.0	670.6
Active	New Generation	230.0	700.0	0.0	0.0	144.6	190.0	0.0	0.0	0.0	1,138.0	0.0	0.0	0.0	0.0	0.0	0.0	481.0	0.0	0.0	0.0	0.0	2,883.6
	Upgrade	0.0	19.0	70.0	528.7	0.0	848.2	43.5	0.0	3.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	92.0	57.3	0.0	0.0	0.0	1,662.2
Total Projects	New Generation	598.2	2,219.0	1,176.0	0.0	176.6	240.0	104.0	0.0	219.4	3,288.8	1,491.0	73.0	522.1	10.0	0.0	559.5	1,169.7	5.0	170.8	2,741.0	0.0	14,764.1
	Upgrade	209.2	284.1	303.7	598.7	0.0	1,289.2	207.5	0.0	3.5	982.7	86.0	0.0	200.0	47.6	0.0	42.0	367.5	89.3	252.3	215.0	0.0	5,178.3

Wind Project Analysis

Table 12-36 shows the status of all wind generation projects, by number of projects that entered PJM generation queues from January 1, 1997, through March 31, 2021, by zone. Of the 115 wind projects classified as new generation or upgrade currently active, suspended or under construction in the PJM generation queue, 40 projects (34.8 percent) are located in the COMED Zone.

Table 12-36 Status of all wind generation queue projects by zone (number of projects): January 1, 1997 through March 31, 2021

		Number of Projects																					
Project Status	Project Classification	ACEC	AEP	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
In Service	New Generation	1	17	16	0	0	26	0	0	0	3	0	0	0	0	0	0	23	0	8	0	0	94
	Upgrade	0	0	1	0	0	5	0	0	0	0	0	0	0	0	0	0	5	0	0	0	0	11
Under Construction	New Generation	0	2	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	4
	Upgrade	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Suspended	New Generation	0	3	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	2	0	0	6
	Upgrade	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Withdrawn	New Generation	18	106	45	8	0	108	15	0	0	21	11	1	2	0	0	0	64	0	46	1	0	446
	Upgrade	2	2	8	0	0	8	0	0	0	3	0	0	0	0	0	0	6	0	2	0	0	31
Active	New Generation	6	22	5	3	0	30	0	0	0	7	6	0	5	0	0	0	1	0	2	1	0	88
	Upgrade	0	1	0	0	0	10	0	0	0	0	3	0	1	0	0	0	1	0	0	0	0	16
Total Projects	New Generation	25	150	68	11	0	164	15	0	0	32	17	1	7	0	0	0	88	0	58	2	0	638
	Upgrade	2	3	10	0	0	23	0	0	0	3	3	0	1	0	0	0	12	0	2	0	0	59

Table 12-37 shows the status of all wind projects by MW that entered PJM generation queues from January 1, 1997, through March 31, 2021, by zone. Of the 31,962.9 MW of wind projects classified as new generation or upgrade currently active, suspended or under construction in the PJM generation queue, 8,135.1 MW (25.5 percent) are located in the COMED Zone.

Table 12-37 Status of all wind generation queue projects by zone (MW): January 1, 1997 through March 31, 2021

		Project MW																				
Project Status	Project Classification	ACEC	AEP	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
In Service	New Generation	7.5	3,094.6	1,114.6	0.0	0.0	4,088.9	0.0	0.0	0.0	322.5	0.0	0.0	0.0	0.0	0.0	0.0	1,065.0	0.0	226.5	0.0	0.0	9,919.6
	Upgrade	0.0	0.0	5.0	0.0	0.0	213.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20.5	0.0	0.0	0.0	0.0	238.7
Under Construction	New Generation	0.0	450.0	310.0	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	760.0
	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	0.0
Suspended	New Generation	0.0	272.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	300.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	165.3	0.0	0.0	737.6
	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	0.0
Withdrawn	New Generation	4,643.6	22,191.8	3,472.2	1,295.6	0.0	25,327.3	2,128.0	0.0	0.0	4,988.4	2,968.8	150.3	1,504.0	0.0	0.0	0.0	5,377.0	0.0	3,375.1	20.0	0.0	77,442.0
	Upgrade	5.0	370.0	119.4	0.0	0.0	755.7	0.0	0.0	0.0	114.0	0.0	0.0	0.0	0.0	0.0	0.0	243.4	0.0	6.0	0.0	0.0	1,613.4
Active	New Generation	3,441.6	4,015.9	457.0	816.1	0.0	7,649.3	0.0	0.0	0.0	5,116.9	1,859.8	0.0	3,759.2	0.0	0.0	0.0	109.9	0.0	349.6	1,300.0	0.0	28,875.3
	Upgrade	0.0	16.6	0.0	0.0	0.0	485.8	0.0	0.0	0.0	0.0	477.3	0.0	510.0	0.0	0.0	0.0	100.3	0.0	0.0	0.0	0.0	1,590.1
Total Projects	New Generation	8,092.7	30,024.3	5,353.8	2,111.7	0.0	37,065.5	2,128.0	0.0	0.0	10,728.1	4,828.6	150.3	5,263.2	0.0	0.0	0.0	6,551.9	0.0	4,116.5	1,320.0	0.0	117,734.4
	Upgrade	5.0	386.6	124.4	0.0	0.0	1,454.7	0.0	0.0	0.0	114.0	477.3	0.0	510.0	0.0	0.0	0.0	364.2	0.0	6.0	0.0	0.0	3,442.2

Solar Project Analysis

Table 12-38 shows the status of all solar generation projects by number of projects that entered PJM generation queues from January 1, 1997, through March 31, 2021, by zone. Of the 1,166 solar projects classified as new generation or upgrade currently active, suspended or under construction in the PJM generation queue, 310 projects (26.6 percent) are located in the Dominion Zone.

Table 12-38 Status of all solar generation queue projects by zone (number of projects): January 1, 1997 through March 31, 2021

		Number of Projects																					
Project Status	Project Classification	ACEC	AEP	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
In Service	New Generation	9	4	8	0	1	1	1	0	0	32	11	0	50	0	0	1	1	1	2	44	0	166
	Upgrade	1	0	3	0	0	0	0	0	0	5	8	0	9	0	0	0	1	0	3	0	0	30
Under Construction	New Generation	0	5	1	0	0	0	0	1	0	14	2	0	2	0	0	0	0	0	0	3	0	28
	Upgrade	0	2	0	0	0	0	0	2	0	5	0	0	0	0	0	0	0	0	0	2	0	11
Suspended	New Generation	0	3	8	0	0	0	1	1	0	6	0	0	0	1	0	0	4	0	0	0	0	24
	Upgrade	0	0	0	0	0	0	0	1	0	0	0	0	2	2	0	0	0	0	0	0	0	5
Withdrawn	New Generation	181	118	89	25	14	40	20	16	1	229	136	13	193	22	1	9	57	21	50	90	0	1,325
	Upgrade	3	4	3	2	0	6	0	0	0	16	1	0	9	0	0	0	3	3	0	3	0	53
Active	New Generation	22	171	73	41	2	49	29	4	4	233	45	34	19	30	1	3	99	8	64	5	0	936
	Upgrade	1	36	13	11	0	5	9	0	1	52	7	1	2	3	0	0	11	0	8	2	0	162
Total Projects	New Generation	212	301	179	66	17	90	51	22	5	514	194	47	264	53	2	13	161	30	116	142	0	2,479
	Upgrade	5	42	19	13	0	11	9	3	1	78	16	1	22	5	0	0	15	3	11	7	0	261

Table 12-39 shows the status of all solar projects by MW that entered PJM generation queues from January 1, 1997, through March 31, 2021, by zone. Of the 82,881.4 MW of solar projects classified as new generation or upgrade currently active, suspended or under construction in the PJM generation queue, 26,162.1 MW (31.6 percent) are located in the AEP Zone.

Table 12-39 Status of all solar generation queue projects by zone (MW): January 1, 1997 through March 31, 2021

		Project MW																					
Project Status	Project Classification	ACEC	AEP	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
In Service	New Generation	62.0	14.7	112.3	0.0	1.1	9.0	2.5	0.0	0.0	1,493.0	130.4	0.0	373.4	0.0	0.0	3.3	13.5	2.5	15.0	231.9	0.0	2,464.5
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	22.0	0.0	0.0	14.3	0.0	0.0	0.0	0.0	0.0	10.0	0.0	0.0	46.3
Under Construction	New Generation	0.0	300.0	10.0	0.0	0.0	0.0	0.0	125.0	0.0	1,124.6	170.0	0.0	21.6	0.0	0.0	0.0	0.0	0.0	0.0	17.5	0.0	1,768.7
	Upgrade	0.0	150.0	0.0	0.0	0.0	0.0	0.0	75.0	0.0	24.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.8	0.0	253.2
Suspended	New Generation	0.0	30.0	191.8	0.0	0.0	0.0	400.0	70.0	0.0	364.9	0.0	0.0	0.0	35.0	0.0	0.0	63.9	0.0	0.0	0.0	0.0	1,155.6
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10.0	0.0	0.0	0.0	0.0	18.6	40.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	68.6
Withdrawn	New Generation	2,014.0	7,882.8	2,147.9	1,521.3	112.3	2,748.8	1,173.9	689.4	20.0	12,960.4	2,151.4	723.9	1,602.4	749.7	78.0	78.4	2,354.8	278.0	874.1	551.4	0.0	40,712.9
	Upgrade	170.0	126.0	27.9	62.0	0.0	110.0	0.0	0.0	0.0	988.8	0.0	0.0	23.8	0.0	0.0	0.0	20.0	3.6	0.0	1.3	0.0	1,533.4
Active	New Generation	739.0	22,912.0	3,095.5	3,462.6	30.0	7,471.9	2,603.5	253.9	50.6	21,186.0	1,708.2	3,168.0	229.4	763.1	120.0	45.8	3,439.1	78.9	1,912.3	38.4	0.0	73,308.2
	Upgrade	0.0	2,770.1	289.8	627.7	0.0	185.0	185.5	0.0	8.3	1,625.2	72.0	40.0	0.0	50.0	0.0	0.0	287.5	0.0	186.1	0.0	0.0	6,327.2
Total Projects	New Generation	2,815.0	31,139.5	5,557.5	4,983.9	143.4	10,229.7	4,179.9	1,138.3	70.6	37,128.8	4,160.0	3,891.9	2,226.7	1,547.8	198.0	127.5	5,871.3	359.5	2,801.4	839.2	0.0	119,409.9
	Upgrade	170.0	3,046.1	317.7	689.7	0.0	295.0	185.5	85.0	8.3	2,660.4	72.0	40.0	56.7	90.0	0.0	0.0	307.5	3.6	196.1	5.1	0.0	8,228.7

Renewable Hybrid Project Analysis

Table 12-40 shows the status of all renewable hybrid generation projects (solar + storage, solar + wind and wind + storage) by number of projects that entered PJM generation queues from January 1, 1997, through March 31, 2021, by zone.[39] Of the 233 renewable hybrid projects currently active, suspended or under construction in the PJM generation queue, 56 projects (24.0 percent) are located in the Dominion Zone.

Table 12-40 Status of all renewable hybrid generation queue projects by zone (number of projects): January 1, 1997 through March 31, 2021

		Number of Projects																					
Project Status	Project Classification	ACEC	AEP	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
In Service	New Generation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	1
	Upgrade	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Under Construction	New Generation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2	0	2
	Upgrade	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Suspended	New Generation	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	1	0	0	2
	Upgrade	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Withdrawn	New Generation	4	10	3	6	0	5	0	0	0	19	0	7	0	0	0	0	1	0	0	8	0	63
	Upgrade	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	1
Active	New Generation	0	39	20	7	0	8	2	0	2	47	2	17	5	11	0	0	16	2	20	1	0	199
	Upgrade	2	4	2	0	0	2	0	0	0	9	0	2	0	1	0	0	2	0	4	0	0	28
Total Projects	New Generation	4	49	23	13	0	13	2	0	2	66	2	24	5	12	0	0	17	2	21	12	0	267
	Upgrade	2	5	3	0	0	2	0	0	0	9	0	2	0	2	0	0	2	0	4	0	0	31

39 PJM does not currently have a definition of a hybrid resource.

Table 12-41 shows the status of all renewable hybrid projects by MW that entered PJM generation queues from January 1, 1997, through March 31, 2021, by zone. Of the 19,273.6 MW of renewable hybrid generation currently active, suspended or under construction in the PJM generation queue, 7,725.7 MW (40.1 percent) are located in the AEP Zone.

Table 12-41 Status of all renewable hybrid generation queue projects by zone (MW): January 1, 1997 through March 31, 2021

		Project MW																				
Project Status	Project Classification	ACEC	AEP	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
In Service	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	0.0	0.0	0.0	0.0	1.1	0.0	1.1
	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	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Under Construction	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	0.0	0.0	0.0	0.0	2.6	0.0	2.6
	Upgrade	0.0	3.2	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	3.2
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	100.0	0.0	0.0	0.0	0.0	90.0	0.0	0.0	190.0
	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	0.0	16.3
Withdrawn	New Generation	14.5	3,360.8	280.0	509.9	0.0	629.9	0.0	0.0	0.0	1,860.0	0.0	960.0	0.0	0.0	0.0	0.0	160.0	0.0	0.0	29.9	0.0	7,805.0
	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	3.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.7
Active	New Generation	0.0	7,002.5	1,465.3	270.9	0.0	1,618.9	80.0	0.0	37.5	3,650.8	130.0	1,957.0	180.0	82.1	0.0	0.0	697.2	562.5	180.0	20.0	0.0	17,934.6
	Upgrade	93.0	720.0	0.0	0.0	0.0	20.0	0.0	0.0	0.0	94.0	0.0	100.0	0.0	0.0	0.0	0.0	0.0	0.0	100.0	0.0	0.0	1,127.0
Total Projects	New Generation	14.5	10,363.3	1,745.3	780.8	0.0	2,248.8	80.0	0.0	37.5	5,510.8	130.0	2,917.0	180.0	182.1	0.0	0.0	857.2	562.5	270.0	53.5	0.0	25,933.2
	Upgrade	93.0	723.2	16.3	0.0	0.0	20.0	0.0	0.0	0.0	94.0	0.0	100.0	0.0	3.7	0.0	0.0	0.0	0.0	100.0	0.0	0.0	1,150.2

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."[40] 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 or transmission 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 nonincumbent 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 12-42 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 March 31, 2021, 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 the DUKE Zone were projects developed by Duke Energy or subsidiaries of Duke Energy, the transmission owner for the DUKE Zone. 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 the DUKE Zone by developers not affiliated with Duke Energy. These project MW are classified as unrelated.

Of the 668,740.7 MW that have entered the queue during the time period of January 1, 1997, through March 31, 2021, 68,949.5 MW (10.3 percent) have been submitted by transmission owners building in their own service territory. PSEG is the transmission owner with the highest percentage of affiliates building in

40 See OATT § 1 (Transmission Owner).

their own service territory. Of the 38,947.0 MW that entered the queue in the PSEG Zone during the time period of January 1, 1997, through March 31, 2021, 14,287.3 MW (36.7 percent) have been submitted by PSEG or one of their affiliated companies.

Table 12-42 Relationship between project developer and transmission owner for all interconnection queue projects MW by unit type: March 31, 2021

				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	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
AEP	AEP	Related	49	16.0	678.0	0.0	0.0	0.0	0.0	34.0	2.4	214.0	0.0	0.0	0.0	247.7	0.0	0.0	3,918.0	90.0	0.0	0.0	0.0	0.0	5,200.1
		Unrelated	775	4,074.0	21,973.5	2,503.1	7.5	127.3	0.0	0.0	453.6	0.0	12.0	0.0	75.4	33,937.9	11,086.5	0.0	10,399.0	0.0	0.0	452.0	30,410.9	0.0	115,512.6
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	0.0	0.0	1,347.5	0.0	0.0	0.0	0.0	0.0	1,427.0
		Unrelated	91	289.9	1,150.0	273.5	0.0	1.9	0.0	0.0	0.0	0.0	0.0	0.0	10.0	4,343.9	80.0	0.0	0.0	0.0	0.0	0.0	2,128.0	0.0	8,277.2
DUQ	DUQ	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	0.0	0.0	0.0
		Unrelated	38	75.0	665.0	222.9	40.0	19.2	0.0	0.0	191.4	1,879.0	0.0	0.0	0.0	78.9	37.5	0.0	2,810.0	0.0	0.0	0.0	0.0	0.0	6,018.9
DOM	DOM	Related	143	350.0	12,338.5	2,045.7	100.0	0.0	0.0	340.0	0.0	1,944.0	0.0	0.0	60.0	3,266.3	17.0	0.0	301.0	0.0	0.0	4.0	2,786.0	0.0	23,552.5
		Unrelated	815	4,721.2	9,244.5	2,225.8	0.5	227.3	0.0	0.0	35.0	0.0	0.0	10.0	119.4	36,523.0	5,587.8	0.0	20.0	0.0	0.0	316.3	8,056.1	0.0	67,086.9
DUKE	DUKE	Related	10	27.3	36.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	106.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	169.7
		Unrelated	34	140.4	667.5	0.0	0.0	0.0	0.0	0.0	112.0	0.0	0.0	0.0	4.8	1,116.9	0.0	0.0	120.0	0.0	0.0	0.0	0.0	0.0	2,161.6
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	0.0	0.0	0.0	821.8
		Unrelated	81	96.3	170.0	73.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3,931.9	3,017.0	0.0	0.0	0.0	0.0	0.0	150.3	0.0	7,438.5
Exelon	ACEC	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	0.0	0.0	0.0	738.3
		Unrelated	352	914.0	8,848.4	807.4	388.0	20.7	2.8	0.0	0.0	0.0	2.0	5.0	10.3	2,976.7	107.5	0.0	15.0	5.5	0.0	10.0	8,097.7	0.0	22,211.0
	BGE	Related	15	22.5	250.0	10.0	0.0	0.0	0.0	0.0	0.0	108.5	0.0	0.0	8.5	20.0	0.0	0.0	10.0	101.0	0.0	0.0	0.0	0.0	530.5
		Unrelated	66	836.6	3,012.1	166.6	18.0	133.0	0.0	0.0	0.4	3,280.0	1.3	0.0	0.0	123.4	0.0	0.0	0.0	2.5	0.0	25.0	0.0	0.0	7,598.9
	COMED	Related	17	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	0.0	0.0	0.0	1,194.0
		Unrelated	462	2,673.6	16,823.2	1,529.2	42.0	65.2	0.0	0.0	22.7	0.0	35.0	0.0	67.7	10,515.7	2,069.8	199.0	1,926.0	91.0	0.0	90.0	38,520.1	0.0	74,670.2
	DPL	Related	8	1.0	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	0.0	0.0	0.0	1,724.4
		Unrelated	339	837.5	5,611.6	1,226.0	600.9	42.6	0.0	0.0	0.0	0.0	0.0	0.0	84.6	4,224.6	130.0	0.0	653.0	15.0	0.0	65.0	5,305.9	0.0	18,796.7
	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	0.0	0.0	7.0	0.0	0.0	0.0	0.0	0.0	7,809.3
		Unrelated	86	25.3	20,355.5	596.5	2.0	15.0	0.0	0.0	0.0	0.0	0.0	17.0	3.7	127.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	21,142.5
	PEPCO	Related	1	1.0	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	1.0
		Unrelated	107	20.0	23,325.9	94.3	34.0	9.0	0.0	0.0	0.0	1,640.0	32.0	0.0	3.5	363.1	562.5	0.0	0.0	6.0	0.0	0.0	0.0	0.0	26,090.3
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	0.0	0.0	1,710.0	0.0	0.0	0.0	0.0	0.0	3,163.0
		Unrelated	492	818.7	27,082.8	1,479.7	0.0	84.4	0.0	0.0	623.3	0.0	140.0	53.8	25.4	5,875.2	1,745.3	0.0	4,092.0	0.0	0.0	184.4	5,478.2	16.3	47,699.4
	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	0.0	0.0	0.0	1,694.0
		Unrelated	165	546.4	13,589.0	598.7	10.5	166.4	0.0	0.0	0.0	0.0	59.7	0.0	6.9	5,673.6	780.8	0.0	0.0	16.5	0.0	0.0	2,111.7	0.0	23,560.2
	JCPLC	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	0.0	0.0	0.0	32.0
		Unrelated	425	1,462.0	15,751.4	722.1	0.0	4.8	0.6	0.0	31.6	0.0	0.6	0.0	12.8	2,271.4	180.0	0.0	0.0	0.0	0.0	30.0	5,773.2	0.0	26,240.5
	MEC	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	0.0	0.0	0.0
		Unrelated	165	619.9	17,458.9	57.6	1,204.4	52.1	0.0	0.0	0.0	93.0	0.0	8.0	23.2	1,637.8	185.8	0.0	0.0	0.0	0.0	84.0	0.0	0.0	21,424.7
	PE	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	0.0	0.0	1,860.0	0.0	0.0	0.0	0.0	0.0	2,399.0
		Unrelated	444	940.2	18,747.9	1,532.2	0.0	214.4	3.0	16.0	46.3	0.0	341.8	8.0	14.8	6,178.8	857.2	0.0	561.0	590.0	0.0	525.0	6,916.1	0.0	37,492.4
OVEC	OVEC	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	0.0	0.0	0.0
		Unrelated	2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	198.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	198.0
PPL	PPL	Related	22	0.0	2,261.0	0.0	0.0	0.0	0.0	0.0	109.0	1,600.0	0.0	0.0	0.0	124.8	0.0	0.0	111.0	0.0	0.0	0.0	0.0	0.0	4,205.8
		Unrelated	361	719.8	23,928.3	423.1	8.0	234.5	0.0	1,200.0	142.6	488.0	19.9	2.4	44.7	2,872.7	280.0	0.0	6,896.6	0.0	0.0	31.0	4,122.5	90.0	41,504.2
PSEG	PSEG	Related	109	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	180.4	3.7	0.0	24.0	44.0	0.0	0.0	0.0	0.0	14,287.3
		Unrelated	237	999.5	18,771.9	1,137.9	600.0	62.5	4.9	0.0	1,000.0	0.0	10.6	0.0	13.7	663.9	49.9	0.0	0.0	25.0	0.0	0.0	1,320.0	0.0	24,659.8
Con Ed	REC	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	0.0	0.0	0.0
		Unrelated	2	0.0	6.9	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	6.9
Total		Related	443	477.8	40,946.4	4,272.8	189.5	0.0	0.0	374.0	396.4	5,886.3	0.0	0.0	68.5	4,003.7	20.7	0.0	9,288.5	235.0	0.0	4.0	2,786.0	0.0	68,949.5
		Unrelated	5539	20,810.3	247,184.1	15,669.6	2,955.8	1,480.3	11.3	1,216.0	2,658.8	7,380.0	654.9	104.2	520.9	123,634.8	26,757.4	199.0	27,492.6	751.5	0.0	1,812.7	118,390.6	106.3	599,791.1

Combined Cycle Project Developer and Transmission Owner Relationships

Table 12-43 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 March 31, 2021, by transmission owner and project status. Of the 48,135.1 combined cycle project MW that have achieved in service or under construction status during this time period, 9,294.6 MW (19.3 percent) have been developed by transmission owners building in their own service territory. EKPC is the transmission owner with the highest percentage of affiliates building combined cycle projects in their own service territory. Of the 991.8 MW that entered the queue in the EKPC Zone during the time period of January 1, 1997, through March 31, 2021, 821.8 MW (82.9 percent) have been submitted by EKPC or one of their affiliated companies.

Table 12-43 Relationship between project developer and transmission owner for all combined cycle project MW in the queue: March 31, 2021

			MW by Project Status					
Parent Company	Transmission Owner	Related to Developer	Active	In Service	Under Construction	Suspended	Withdrawn	Total
AEP	AEP	Related	0.0	678.0	0.0	0.0	0.0	678.0
		Unrelated	2,520.0	2,738.0	3,495.0	0.0	13,220.5	21,973.5
AES	DAY	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	0.0	1,150.0	0.0	1,150.0
DUQ	DUQ	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
DOM	DOM	Related	75.0	4,762.5	0.0	0.0	7,501.0	12,338.5
		Unrelated	1,600.0	2,044.1	0.0	0.0	5,600.4	9,244.5
DUKE	DUKE	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	ACEC	Related	0.0	0.0	0.0	0.0	730.0	730.0
		Unrelated	7.6	879.0	0.0	0.0	7,961.8	8,848.4
	BGE	Related	0.0	130.0	0.0	0.0	120.0	250.0
		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	1,361.7	1,233.6	2,350.9	0.0	11,877.0	16,823.2
	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	3,673.5	0.0	0.0	16,615.0	20,355.5
	PEPCO	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	1,788.6	0.0	0.0	21,537.3	23,325.9
First Energy	APS	Related	0.0	525.0	0.0	0.0	928.0	1,453.0
		Unrelated	1,784.0	1,720.0	664.7	1,136.0	21,778.1	27,082.8
	ATSI	Related	0.0	0.0	0.0	0.0	1,678.0	1,678.0
		Unrelated	550.0	2,943.0	1,152.0	1,895.0	7,049.0	13,589.0
	JCPLC	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	1,775.8	0.0	35.0	13,940.6	15,751.4
	MEC	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	2,640.9	75.0	0.0	14,743.0	17,458.9
	PE	Related	0.0	0.0	0.0	0.0	534.0	534.0
		Unrelated	248.0	2,042.3	0.0	0.0	16,457.6	18,747.9
OVEC	OVEC	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
PPL	PPL	Related	0.0	600.0	0.0	0.0	1,661.0	2,261.0
		Unrelated	55.0	5,862.0	51.6	0.0	17,959.7	23,928.3
PSEG	PSEG	Related	0.0	2,488.0	51.1	0.0	9,297.0	11,836.1
		Unrelated	0.0	806.4	0.0	0.0	17,965.5	18,771.9
Con Ed	REC	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	75.0	9,243.5	51.1	0.0	31,576.8	40,946.4
		Unrelated	8,193.3	31,051.3	7,789.2	4,667.0	195,483.2	247,184.1

Combustion Turbine – Natural Gas Project Developer and Transmission Owner Relationships

Table 12-44 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 March 31, 2021, by transmission owner and project status. Of the 9,739.3 CT – natural gas project MW that have achieved in service or under construction status during this time period, 2,145.0 (22.0 percent) have been developed by Transmission Owners building in their own service territory. PSEG is the transmission owner with the highest percentage of affiliates building CT – natural gas projects in their own service territory. Of the 2,956.0 MW that entered the queue in the PSEG Zone during the time period of January 1, 1997, through March 31, 2021, 1,818.1 MW (61.5 percent) have been submitted by PSEG or one of their affiliated companies.

Table 12-44 Relationship between project developer and transmission owner for all CT – natural gas project MW in the queue: March 31, 2021

			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	719.0	208.0	0.0	0.0	1,576.1	2,503.1
AES	DAY	Related	0.0	38.0	0.0	0.0	0.0	38.0
		Unrelated	43.5	22.0	0.0	0.0	208.0	273.5
DUQ	DUQ	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	3.5	0.0	219.4	0.0	0.0	222.9
DOM	DOM	Related	1,138.0	824.0	0.0	0.0	83.7	2,045.7
		Unrelated	0.0	1,182.7	0.0	0.0	1,043.1	2,225.8
DUKE	DUKE	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	73.0	73.0
Exelon	ACEC	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	230.0	404.4	0.0	0.0	173.0	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	9.0	166.6
	COMED	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	1,038.2	371.0	87.0	0.0	33.0	1,529.2
	DPL	Related	0.0	351.0	0.0	0.0	0.0	351.0
		Unrelated	0.0	1,226.0	0.0	0.0	0.0	1,226.0
	PECO	Related	0.0	5.0	0.0	0.0	0.0	5.0
		Unrelated	0.0	596.0	0.0	0.0	0.5	596.5
	PEPCO	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	57.3	37.0	0.0	0.0	0.0	94.3
First Energy	APS	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	70.0	1,363.7	12.0	30.0	4.0	1,479.7
	ATSI	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	528.7	40.0	5.0	0.0	25.0	598.7
	JCPLC	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	720.0	0.0	0.0	2.1	722.1
	MEC	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	44.1	13.5	0.0	0.0	57.6
	PE	Related	0.0	5.0	0.0	0.0	0.0	5.0
		Unrelated	573.0	384.9	12.5	0.0	561.8	1,532.2
OVEC	OVEC	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
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	675.0	234.0	1,137.9
Con Ed	REC	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	1,138.0	2,145.0	0.0	0.0	989.8	4,272.8
		Unrelated	3,407.8	7,244.9	349.4	705.0	3,962.5	15,669.6

Wind Project Developer and Transmission Owner Relationships

Table 12-45 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 March 31, 2021, by transmission owner and project status. Of the 10,918.3 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. Dominion is the transmission owner with the highest percentage of affiliates building wind projects in their own service territory. Of the 10,842.1 MW that entered the queue in the Dominion Zone during the time period of January 1, 1997, through March 31, 2021, 2,786.0 MW (25.7 percent) have been submitted by Dominion or one of their affiliated companies.

Table 12-45 Relationship between project developer and transmission owner for all wind project MW in the queue: March 31, 2021

			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	4,032.6	3,094.6	450.0	272.0	22,561.8	30,410.9
AES	DAY	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	0.0	0.0	2,128.0	2,128.0
DUQ	DUQ	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
DOM	DOM	Related	2,640.0	12.0	0.0	0.0	134.0	2,786.0
		Unrelated	2,476.9	310.5	0.0	300.3	4,968.4	8,056.1
DUKE	DUKE	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	ACEC	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	3,441.6	7.5	0.0	0.0	4,648.6	8,097.7
	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	8,135.1	4,302.1	0.0	0.0	26,082.9	38,520.1
	DPL	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	2,337.1	0.0	0.0	0.0	2,968.8	5,305.9
	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	457.0	1,119.6	310.0	0.0	3,591.6	5,478.2
	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
	JCPLC	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	4,269.2	0.0	0.0	0.0	1,504.0	5,773.2
	MEC	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
	PE	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	210.2	1,085.5	0.0	0.0	5,620.3	6,916.1
OVEC	OVEC	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
PPL	PPL	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	349.6	226.5	0.0	165.3	3,381.1	4,122.5
PSEG	PSEG	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	1,300.0	0.0	0.0	0.0	20.0	1,320.0
Con Ed	REC	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	2,640.0	12.0	0.0	0.0	134.0	2,786.0
		Unrelated	27,825.3	10,146.3	760.0	737.6	78,921.4	118,390.6

Solar Project Developer and Transmission Owner Relationships

Table 12-46 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 March 31, 2021, by transmission owner and project status. Of the 4,532.7 solar project MW that have achieved in service or under construction status during this time period, 1,223.1 MW (27.0 percent) have been developed by transmission owners building in their own service territory. PSEG is the transmission owner with the highest percentage of affiliates building solar projects in their own service territory. Of the 844.3 MW that entered the queue in the PSEG Zone during the time period of January 1, 1997, through March 31, 2021, 180.4 MW (21.4 percent) have been submitted by PSEG or one of their affiliated companies.

Table 12-46 Relationship between project developer and transmission owner for all solar project MW in the queue: March 31, 2021

			MW by Project Status					
Parent Company	Transmission Owner	Related to Developer	Active	In Service	Under Construction	Suspended	Withdrawn	Total
AEP	AEP	Related	48.0	14.7	20.0	10.0	155.0	247.7
		Unrelated	25,634.1	0.0	430.0	20.0	7,853.8	33,937.9
AES	DAY	Related	0.0	0.0	0.0	0.0	21.5	21.5
		Unrelated	2,789.0	2.5	0.0	400.0	1,152.4	4,343.9
DUQ	DUQ	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	58.9	0.0	0.0	0.0	20.0	78.9
DOM	DOM	Related	1,981.9	726.4	306.1	0.0	251.9	3,266.3
		Unrelated	20,829.3	788.6	842.9	364.9	13,697.3	36,523.0
DUKE	DUKE	Related	50.0	0.0	0.0	0.0	56.4	106.4
		Unrelated	203.9	0.0	200.0	80.0	633.0	1,116.9
EKPC	EKPC	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	3,208.0	0.0	0.0	0.0	723.9	3,931.9
Exelon	ACEC	Related	0.0	0.0	0.0	0.0	8.3	8.3
		Unrelated	739.0	62.0	0.0	0.0	2,175.8	2,976.7
	BGE	Related	0.0	0.0	0.0	0.0	20.0	20.0
		Unrelated	30.0	1.1	0.0	0.0	92.3	123.4
	COMED	Related	0.0	9.0	0.0	0.0	0.0	9.0
		Unrelated	7,656.9	0.0	0.0	0.0	2,858.8	10,515.7
	DPL	Related	0.0	7.4	0.0	0.0	0.0	7.4
		Unrelated	1,780.2	123.0	170.0	0.0	2,151.4	4,224.6
	PECO	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	45.8	3.3	0.0	0.0	78.4	127.5
	PEPCO	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	78.9	2.5	0.0	0.0	281.6	363.1
First Energy	APS	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	3,385.3	112.3	10.0	191.8	2,175.8	5,875.2
	ATSI	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	4,090.3	0.0	0.0	0.0	1,583.3	5,673.6
	JCPLC	Related	0.0	0.0	0.0	0.0	12.0	12.0
		Unrelated	229.4	387.7	21.6	18.6	1,614.2	2,271.4
	MEC	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	813.1	0.0	0.0	75.0	749.7	1,637.8
	PE	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	3,726.6	13.5	0.0	63.9	2,374.8	6,178.8
OVEC	OVEC	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	120.0	0.0	0.0	0.0	78.0	198.0
PPL	PPL	Related	124.8	0.0	0.0	0.0	0.0	124.8
		Unrelated	1,973.7	25.0	0.0	0.0	874.1	2,872.7
PSEG	PSEG	Related	0.0	134.3	5.2	0.0	40.9	180.4
		Unrelated	38.4	97.6	16.1	0.0	511.8	663.9
Con Ed	REC	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	2,204.6	891.8	331.3	10.0	566.0	4,003.7
		Unrelated	77,430.7	1,619.0	1,690.6	1,214.2	41,680.4	123,634.8

Renewable Hybrid Project Developer and Transmission Owner Relationships

Table 12-47 shows the relationship between the project developer and transmission owner for all renewable hybrid project MW that have entered the PJM generation queue from January 1, 1997, through March 31, 2021, by transmission owner and project status. Of the 6.8 renewable hybrid project MW that have achieved in service or under construction status during this time period, 3.7 MW (53.9 percent) have been developed by transmission owners building in their own service territory. PSEG is the transmission owner with the highest percentage of affiliates building hybrid projects in their own service territory. Of the 53.6 MW that entered the queue in the PSEG Zone during the time period of January 1, 1997, through March 31, 2021, 3.7 MW (6.9 percent) have been submitted by PSEG or one of their affiliated companies.

Table 12-47 Relationship between project developer and transmission owner for all hybrid project MW in the queue: March 31, 2021

			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	7,722.5	0.0	3.2	0.0	3,360.8	11,086.5
AES	DAY	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	80.0	0.0	0.0	0.0	0.0	80.0
DUQ	DUQ	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	37.5	0.0	0.0	0.0	0.0	37.5
DOM	DOM	Related	17.0	0.0	0.0	0.0	0.0	17.0
		Unrelated	3,727.8	0.0	0.0	0.0	1,860.0	5,587.8
DUKE	DUKE	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	2,057.0	0.0	0.0	0.0	960.0	3,017.0
Exelon	ACEC	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	93.0	0.0	0.0	0.0	14.5	107.5
	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	1,638.9	0.0	0.0	0.0	629.9	2,268.8
	DPL	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	130.0	0.0	0.0	0.0	0.0	130.0
	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	562.5	0.0	0.0	0.0	0.0	562.5
First Energy	APS	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	1,465.3	0.0	0.0	16.3	280.0	1,761.6
	ATSI	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	270.9	0.0	0.0	0.0	509.9	780.8
	JCPLC	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	180.0	0.0	0.0	0.0	0.0	180.0
	MEC	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	82.1	0.0	0.0	100.0	3.7	185.8
	PE	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	697.2	0.0	0.0	0.0	160.0	857.2
OVEC	OVEC	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
PPL	PPL	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	280.0	0.0	0.0	90.0	0.0	370.0
PSEG	PSEG	Related	0.0	1.1	2.6	0.0	0.0	3.7
		Unrelated	20.0	0.0	0.0	0.0	29.9	49.9
Con Ed	REC	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	17.0	1.1	2.6	0.0	0.0	20.7
		Unrelated	19,044.6	0.0	3.2	206.3	7,808.7	27,062.7

Regional Transmission Expansion Plan (RTEP)[41]

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.

The RTEP process initially considered only factors such as load growth and the generation interconnection requests in its development of the 15 year plan. Currently, the RTEP process includes a broader range of inputs including 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.

Market Efficiency Process

PJM's Regional Transmission Expansion Plan (RTEP) process includes a market efficiency analysis. The stated 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.[42] 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 of the proposed project must reduce congestion on one or more constraints by at least one dollar, meet a benefit/cost ratio threshold of at least 1.25:1 and have an independent cost review, performed by PJM, if expected costs are over $50 million. PJM provides the review of a project with a projected cost of over $50 million using its own staff or outside consultants that are hired to assist in the review. PJM presents its findings to the TEAC where PJM's findings are reviewed by the stakeholders. While stakeholders can comment on the findings, PJM makes the final decision about what costs will be used for the purpose of calculating the Benefit/Cost ratio for the project. 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 concurrently with the long-term proposal window for reliability projects.

PJM's first market efficiency analysis was performed in 2013, prior to Order 1000. The 2013 window was open from August 12, 2013, through September 26, 2013. This window accepted proposals to address historical congestion on 25 identified flowgates. PJM received 17 proposals from six entities. One project was approved by the PJM Board.

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

41 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. 48 (October 1, 2020).

42 See PJM. "*PJM Regional Transmission Expansion Plan: 2019*," (February 29, 2020) <https://www.pjm.com/-/media/library/reports-notices/2019-rtep/2019-rtep-book-1.ashx>.

window was open from November 1, 2014, through February 28, 2015. This window accepted proposals to address historical congestion on 12 identified flowgates. PJM received 93 proposals from 19 entities. Thirteen projects were approved by the PJM Board.

The second market efficiency cycle was performed during the 2016/2017 RTEP long term window. The 2016/2017 long term window was open from November 1, 2016, through February 28, 2017. This window accepted proposals to address historical congestion on four identified flowgates. PJM received 96 proposals from 20 entities. Four projects were approved by the PJM Board.

PJM also held an addendum 2016/2017 long term window. This 2016/2017 1A long term window was open from September 14, 2017, through September 28, 2017. This window accepted proposals to address historical congestion on one identified flowgate. PJM received three proposals from two entities. One project was approved by the PJM Board.

The fourth market efficiency cycle was performed for the 2018/2019 RTEP long term window. The 2018/2019 long term window was open from November 2, 2018, through March 15, 2019. This window accepted proposals to address historical congestion on one internal and three interregional flowgates. PJM received 33 proposals from 10 entities. One project was approved by the PJM Board to address the historical congestion on the internal flowgate, and one project was approved by the PJM Board to address the historical congestion on one of the interregional flowgates.[43]

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 net present value of calculated energy market benefits and calculated reliability pricing model (RPM) benefits for a 15 year period, starting with the projected in service date of the project. PJM measures benefits as reductions in estimated load charges and production costs in the energy market and reductions in estimated load capacity payments and in system capacity costs in the capacity market, but does not weight increases and decreases in benefits equally. The method for calculating energy market benefits and reliability pricing model benefits 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 uses an energy market simulation tool that produces an hourly least-cost, security constrained market solution, including 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.

The definition of the energy benefit analysis depends on whether the project is regional or subregional. For a regional project, the energy benefit for each modeled year is equal to 50 percent of the change in system wide total system energy production costs with and without the project plus 50 percent of the change in zonal load payments with and without the project, including only those zones where the project reduced the load payments. For subregional projects, the calculation of benefits for each modeled year ignores any impact on system wide energy production costs and is instead based only the change in zonal load energy payments with and without the project, but including only those zones where the project reduced the load energy payments.

In both the regional and subregional analysis, changes in zonal load energy payments are netted against changes in the estimated value of any Auction Revenue Rights (ARR) that sink in that zone for purposes of determining whether a zone benefits from a proposed RTEP project. Estimated ARR credits are calculated for each simulated year using the most recent planning year's actual ARR MW combined with FTR prices assumed to be equal to the market simulation's CLMP differences between ARR source and sink points. The value

43 No proposals effectively resolved the congestion on two of the three identified interregional market efficiency flowgates. One proposal received provisional approval by the PJM Board, pending approval by the MISO Board.

of the ARR rights with and without the RTEP project is evaluated based on changes in modeled CLMPs on the latest 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 and the value of the ARRs are assumed to match the forecasted CLMP differences on the ARR paths.

The Reliability Pricing Model (RPM) Benefit analysis is conducted using the RPM solution software, with and without the proposed RTEP project, using a set of estimated capacity offers.

The definition of the benefit in the RPM benefit analysis depends on whether the project is regional or subregional. For a regional project, the RPM benefit for each modeled year is equal to 50 percent of the change in system wide total system capacity payments with and without the project plus 50 percent of the change in zonal capacity payments with and without the project, including only those zones where the project reduced the capacity payments. For subregional projects, the reliability pricing model benefits for each modeled year ignores any impact on system wide total capacity payments and is equal to the change in zonal capacity payments with and without the project, including only those zones where the project reduced the capacity payments.

The difference in the benefits calculation used in the regional and subregional cost benefit threshold tests is related to how the direct costs of the transmission projects 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.

There are significant issues with PJM's benefit/cost analysis. The current rules governing benefit/cost analysis of competing transmission projects do not accurately measure the relative costs and benefits of transmission projects. The current rules do not account for the fact that the benefits of projects are uncertain and highly sensitive to the modeling assumptions used. The current rules explicitly ignore the increased zonal load costs that a project may create. The current rules do not account for the fact that the project costs are nonbinding estimates, are not subject to cost caps and may significantly exceed the estimated costs. These flaws have contributed to PJM approving market efficiency projects with forecasted benefits that do not exceed the forecasted costs.

The recent introduction of storage as transmission assets (SATA) raises a number of additional concerns about PJM's benefit/cost analysis. PJM's benefit/cost analysis uses a 15 year forecast for purposes of evaluating benefits and costs of traditional transmission assets with an expected useful life of 50 years or more. Using the same 15 year horizon does not make sense for SATA resources with an expected useful life of 10 years or less, depending on use. Using a 15 year benefit horizon will exaggerate the forecasted benefit stream relative to the stream of benefits that could be produced over the expected useful life relative to traditional transmission assets. Further, the rules for how to account for the actual, and forecasted, revenues and charges for operating the SATA to provide transmission load relief have not been established. Without clear rules on how to allocate operational revenues and costs it is impossible to develop forecasted benefits and/or costs of a SATA project.

The broader issue is that the market efficiency project approach explicitly allows transmission projects to compete against future generation projects, but without allowing the generation projects to compete. Projecting speculative transmission related benefits for 15 years based on the existing generation fleet and existing patterns of congestion eliminates the potential for new generation to respond to market signals. The market efficiency process allows assets built under the cost of service regulatory paradigm to displace generation assets built under the competitive market paradigm. The MMU recommends that the market efficiency process be eliminated.

The Transource Project

The Transource Project (Project 9A) is an example of a PJM approved market efficiency project that passed PJM's 1.25 benefit/cost threshold test despite having benefits, if accurately calculated, that were less than forecasted costs. This project also illustrates the risks of ignoring potential cost increases given that the costs included in the benefit/cost calculation are nonbinding estimates. The Transource Project was proposed in PJM's 2014/2015 RTEP long term window. PJM's 2014/2015 RTEP long term window was the first market efficiency cycle under Order 1000. The 2014/2015 long term window was open from November 1, 2014, through February 28, 2015. This window accepted proposals to address historical congestion on 12 identified flowgates. The AP South Interface was one of the 12 identified flow gates listed in the 2014/15 RTEP Long Term Proposal Window Problem Statement.

A total of 41 market efficiency projects were proposed to address congestion on the AP South Transmission Interface. Transource Energy LLC, together with Dominion High Voltage, submitted a proposal referenced by PJM as Project 9A (or IEC or the Transource project) to address AP South related congestion.

Project 9A was considered a subregional project based on its voltage level, meaning that changes in forecasted system costs were not considered for purposes of estimating the benefit/cost ratios. Instead, only reductions in zonal load costs were considered as a benefit of the project. Any increases in zonal load costs were ignored in the analysis.

The initial study had a benefit to cost ratio of 2.48, with a capital cost of $340.6 million. The sum of the positive (energy cost reductions) effects was $1,188.07 million. The sum of negative effects (energy cost increases) was $851.67 million. The net actual benefit of the project in the study was therefore $336.40 million, not the $1,188.07 used in the study. Using the total benefits (positive and negative) to compare to the net present value of costs, the benefit to cost ratio was 0.70, not 2.48. The project should have been rejected on those grounds.

Subsequent studies of the 9A project have reduced its benefit/cost ratio as a result of increased costs, decreased congestion on the AP South Interface since 2014 and a reduction in peak load forecasts since 2015. The most recent study produced by PJM in 2019 using simulations for years 2017, 2021, 2024 and 2027 had a benefit cost ratio of 2.10 with a capital cost of $383.63 million. The sum of the positive (energy cost reductions) effects was $855.19 million, a reduction of $322 million (28.0 percent) from the initial study. The sum of negative effects (energy cost increases) was $827.34 million, a reduction of $27.86 million (3.3 percent) from the results of the initial study. The net actual benefit of the project in the 2019 study was $27.85 million, not the $1,188.07 from the initial study. Using the total benefits (positive and negative) to compare to the net present value of costs in the 2019 analysis, the benefit to cost ratio was 0.07, not 2.10. The project should have been rejected on those grounds.

PJM MISO Interregional Market Efficiency Process (IMEP)

PJM and MISO developed a process to facilitate the construction of interregional projects in response to the Commission's concerns about interregional coordination along the PJM-MISO seam. This process, called the Interregional Market Efficiency Process (IMEP), operates on a two year study schedule and is designed to address forward looking congestion. To qualify as an IMEP project, the project must be evaluated in a joint study process, qualify as an economic transmission enhancement in both PJM and MISO transmission expansion models and meet specific IMEP cost benefit criteria.[44] The allocation of costs to each RTO for IMEPs will be in proportion to the benefits received.

While the IMEP process is a joint effort, PJM and MISO perform their own analysis of benefits to their own system and each uses a different modeling approach and a different metric for determining the benefits of a proposed project. PJM makes use of the benefit/cost analysis used for its own internal market efficiency projects which will, by definition, overstate project benefits

44 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.," (December 11, 2008) <http://www.pjm.com/directory/merged-tariffs/miso-joa.pdf>.

by ignoring areas where energy costs are increased. MISO, on the other hand, measures benefits as changes in projected system wide production cost caused by the project. The use of different approaches to measuring benefits is an issue when studying potential benefits of projects in a joint effort, and when using the defined benefits to allocate the costs of IMEP projects to each RTO. PJM's approach will over allocate the costs of IMEP projects to PJM members.

PJM and MISO conducted a two year interregional market efficiency project study in 2018/2019 and included the investigation of forward looking congestion on three market to market flowgates. Proposals were received during the 2018/2019 long term window, which was open from November 2, 2018, through March 15, 2019. PJM and MISO received 10 proposals from seven entities. As a result of this analysis, the RTOs recommended one IMEP project, the Bosserman to Trail Creek 138 kV Project.[45] The approved project has an in service cost of $24.7 million, and counting only PJM positive zonal benefits, a total present value of projected benefits of $69.2 million. Ignoring PJM zones with negative benefits (increased costs to load) the project has a calculated PJM benefit/cost ratio of 2.63. MISO, using both positive and negative zonal effects, calculated the projected benefits of the project to be $8.4 million. Based on the proportion of the calculated benefits, PJM is to be allocated 89.1 percent ($23.4 million) of the project costs and MISO is to be allocated 10.9 percent ($2.9 million) of the interregional costs. The PJM board approved the recommended project in December 2019. The MISO board approved the recommended project in September 2020.

Using a rational measure of benefits and costs, the Bosserman to Trail Creek 138 kV Project should not have been approved. Including the projected positive and negative benefits of the project to all PJM zones, the projected total benefits of the project drops from $69.2 million to -$68.1 million dollars. PJM analysis shows benefits to only one zone of $69.2 million, with the negative effect on all other zones of -$137.3 million. The resulting benefit/cost ratio would be -2.59. Even including the net MISO benefit of $8.4 million, the total projected benefit of the project would still be a -$59.7 million dollars. Allocating the costs of the project based on the proportion of total regional benefit (-$68.1 million to PJM and $8.4 million to MISO) would have allocated 100 percent of the cost to MISO, resulting in a benefit/cost ratio of 0.32 to MISO, and a rejection of the project by MISO.

PJM and MISO are currently in the second year of the two year 2020/2021 IMEP cycle. The RTOs are currently coordinating the development of their regional models.

PJM MISO Targeted Market Efficiency Process (TMEP)

PJM and MISO developed the Targeted Market Efficiency Process (TMEP) to facilitate the resolution of historic congestion issues that could be addressed through small, quick implementation projects. The TMEP process operates on a 12 month study schedule. To qualify as a TMEP project, the project must have an estimated in service date by the third summer peak season from the year the project was approved, have an estimated cost of less than $20 million and must have estimated benefits, based on the projected congestion cost relief over a four year period, that exceed the expected installed capacity cost of the proposed project.[46] [47]

The benefit of a proposed TMEP project is calculated as the value of eliminating congestion on the affected constraint over a four year period. PJM and MISO calculate the estimated value of eliminating congestion by calculating the average congestion for the two prior years prior and multiplying by four.

The allocation of costs to each RTO for an approved TMEP project will be in proportion to the benefits received by that RTO.[48] The proportion of benefits is calculated using the average shadow price of the constraint times the dfax to affected downstream buses times MW of load at the buses, which is effectively the proportion of congestion paid by the RTO. Within an RTO, the RTO's share of the cost of the approved project is allocated to each transmission control area in proportion to the benefits received by each transmission control area.

45 Analysis showed that no projects met the B/C criteria on two of the identified flowgates.

46 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.," (December 11, 2008) <http://www.pjm.com/directory/merged-tariffs/miso-joa.pdf>.

47 On November 2, 2017, PJM submitted a compliance filing including additional revisions to the MISO-PJM JOA to include stakeholder feedback in the TMEP project selection process. See *PJM Interconnection, L.L.C*, Docket No. ER17-718-000, et al. (November 2, 2017).

48 See *PJM Interconnection, L.L.C*, Docket No. ER17-729-000 (December 30, 2016).

The first Targeted Market Efficiency Process (TMEP) analysis occurred in 2017 and included the investigation of historical congestion on an initial set of 50 market to market flowgates. The causes of congestion on these flowgates were analyzed. If the historical congestion was a result of outages, or if the congestion was expected to be mitigated by planned upgrades already included in the PJM RTEP or MISO MTEP, then the flowgate was eliminated from consideration in the TMEP process. As a result of this analysis, potential short term upgrades were identified for 13 of the initial 50 flowgates. PJM and MISO conducted a market efficiency and power flow analysis to determine the potential to eliminate the identified congestion on the 13 flowgates and recommended five TMEP projects. The five projects address $59.0 million in historical congestion, with a calculated TMEP benefit of $99.6 million. The projects have a total cost of $20.0 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.[49]

The second Targeted Market Efficiency Process analysis occurred in 2018 and included the investigation of historical congestion on an initial set of 61 market to market flowgates. As a result of this analysis, potential short term upgrades were identified for 20 of the initial 61 flowgates. PJM and MISO conducted a market efficiency and power flow analysis to determine the potential to eliminate the identified congestion on the 20 flowgates and recommended two TMEP projects. The two projects address $25.0 million in historical congestion, with a calculated 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 presented the two recommended projects to their boards in December 2018, and both boards approved the projects.[50]

With only one additional year of historical information, and the fact that many of the same constraints were evaluated in the 2018 TMEP process, PJM and MISO did not conduct a TMEP study in 2019.

As a result of decreases in M2M congestion and the addition of transmission upgrades already in process that affect the top congested historical M2M flowgates, PJM and MISO did not conduct a TMEP study in 2020.

The PJM and MISO TMEP process for measuring the projected benefits of a TMEP transmission projects is flawed. The current rules incorrectly count congestion as a cost to load without accounting for how the congestion dollars are or are not returned to the load through the ARRs and FTRs. The benefit of a TMEP transmission upgrade should be the expected difference in the total cost of energy before and after the upgrade to all affected load. This measurement would include the change in expected LMP of all affected load before and after the upgrade, times the MW of load, plus the change in congestion dollars returned to the affected load before and after the upgrade. Congestion revenue returned to load is not a cost to the load, it is a credit against the overpayment of load payments relative to generation credits caused by the transmission constraint. Ignoring the return of congestion from ARRs/FTRs overstates the potential benefits of eliminating congestion through the TMEP upgrades, and ignores the value of smaller upgrades that may not eliminate a constraint, but may reduce the average cost of energy for load.

Supplemental Transmission Projects

Supplemental projects are asserted to be "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."[51] Attachment M-3 of the PJM OATT defines the process that Transmission Owners (TO) must follow in adding Supplemental Projects in their local plan.

The M-3 Process requires TOs to present the criteria, assumptions and models that they will use to plan and identify Supplemental Projects on a yearly basis. The criteria identified for Supplemental Projects are very broad and include: equipment material condition, performance and risk, operational flexibility

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

50 See PJM. "*MISO PJM IPSAC*," (January 18, 2019) <https://www.pjm.com/-/media/committees-groups/stakeholder-meetings/ipsac/20190118/20190118-ipsac-presentation.ashx>.

51 See PJM. Planning. "Transmission Construction Status," (Accessed on March 31, 2021) <http://www.pjm.com/planning/rtep-upgrades-status/construct-status.aspx>.

and efficiency, infrastructure resilience, customer service or other, as well as asset management.

While the identification of the criteria violations and solutions are reviewed, and stakeholders have the opportunity to comment, the solution that is submitted in the Local Plan is the Transmission Owner's decision. PJM conducts a do no harm analysis to ensure the Supplemental Projects do not negatively affect the reliability of the system. Supplemental Projects are ultimately included in PJM's Regional Transmission Expansion Plan and are allocated 100 percent to the zone in which the transmission facilities are located. Supplemental Projects may displace projects that would have otherwise been implemented through the RTEP process.

Supplemental projects are currently exempt from the Order No. 1000 competitive process.[52] Transmission owners have a clear incentive to increase investments in rate base given that transmission owners are paid for these projects on a cost of service basis.

Figure 12-5 shows the latest cost estimate of all baseline and supplemental projects by expected in service year. FERC Order No. 890 was issued on February 16, 2007, and implemented in PJM starting in 2008. Order No. 890 required Transmission Providers to participate in a coordinated, open and transparent planning process. Prior to the implementation of Order No. 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 12-5, Table 12-48 and Table 12-49 because PJM did not track or report such projects. There has been a significant increase in supplemental projects coincident with the implementation of Order No. 890 starting in 2008 and the competitive planning process introduced by FERC Order No. 1000 starting in 2011.

Figure 12-5 Cost estimate of baseline and supplemental projects by expected in service year: January 1, 1998 through March 31, 2021

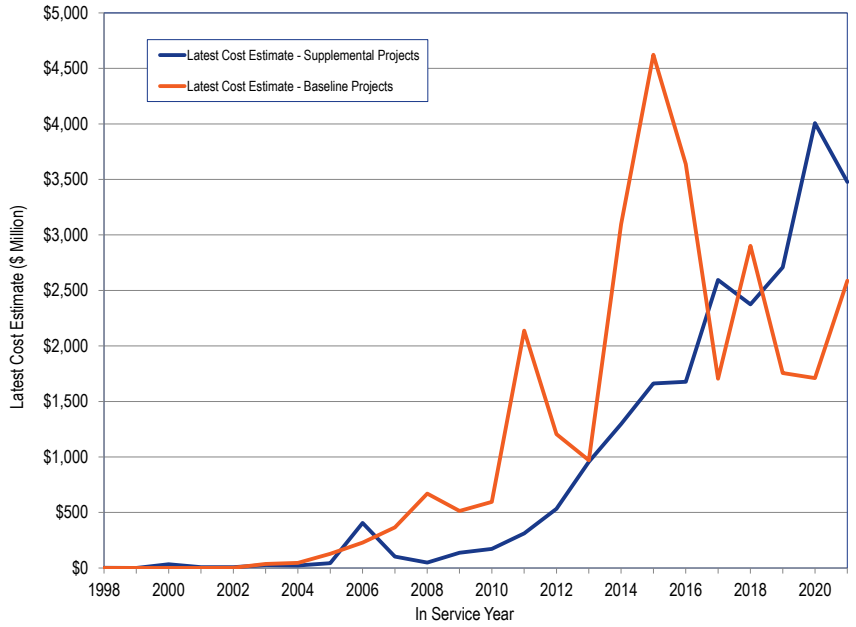


Table 12-48 shows the number of supplemental projects by expected in service year for each transmission zone. The average number of supplemental projects in each expected in service year increased by 795.0 percent, from 20 for years 1998 through 2007 (pre Order No. 890) to 179 for years 2008 through 2021 (post Order No. 890).

52 The FERC accepted tariff provisions that exclude supplemental projects from competition in the RTEP. 162 FERC ¶ 61,129 (2018), *reh'g denied*, 164 FERC ¶ 61,217 (2018).

Table 12-48 Number of supplemental projects by expected in service year and zone: 1998 through 2040

Year	ACEC	AEP	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
1998	0	0	0	0	0	0	0	0	0	0	3	0	0	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	0	0	2
2000	0	0	0	0	0	0	0	0	0	0	11	0	0	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	0	0	14
2002	0	0	0	0	0	0	0	0	0	0	10	0	0	0	0	0	0	0	0	0	0	10
2003	4	0	0	0	0	0	0	0	0	0	10	0	0	0	0	0	2	0	0	0	0	16
2004	5	0	10	0	0	10	0	0	0	0	12	0	2	0	0	0	0	0	0	2	0	41
2005	4	2	8	0	0	4	0	0	0	1	14	0	1	0	0	1	2	0	0	2	0	39
2006	4	2	5	0	0	6	0	0	0	0	9	0	1	0	0	0	1	0	2	1	0	31
2007	2	1	5	0	4	5	0	0	4	0	7	0	0	0	0	0	2	0	1	6	0	37
2008	4	0	15	0	1	6	0	0	1	7	4	0	0	1	0	0	0	0	3	1	0	43
2009	3	1	6	0	1	8	0	0	3	3	5	0	0	0	0	5	1	0	1	2	0	39
2010	0	6	7	0	3	4	0	0	6	3	0	0	1	2	0	2	0	0	3	5	0	42
2011	0	8	8	0	0	2	0	0	5	2	0	0	1	0	0	4	0	0	6	4	0	40
2012	0	5	6	4	1	2	0	7	3	16	1	0	2	0	0	1	0	0	5	11	0	64
2013	5	21	4	5	0	11	0	6	4	13	1	0	1	1	0	1	0	1	14	19	0	107
2014	3	32	2	8	2	14	0	5	6	18	3	2	2	0	0	1	2	0	9	18	0	127
2015	4	16	2	9	1	37	0	8	4	17	5	4	2	0	0	1	0	4	7	24	0	145
2016	6	17	4	17	0	26	0	6	2	13	4	2	0	1	0	3	2	3	12	30	0	148
2017	8	107	3	26	1	23	0	3	8	31	11	5	0	3	0	0	3	1	23	44	0	300
2018	10	143	3	13	1	20	0	14	3	22	6	4	0	0	0	2	0	1	20	26	0	288
2019	3	157	4	30	6	14	2	16	1	33	8	5	3	14	0	1	15	0	15	27	0	354
2020	5	136	4	33	9	12	5	13	2	26	2	6	10	18	0	2	34	1	15	21	0	354
2021	2	204	3	33	2	4	7	15	1	29	2	6	12	50	5	6	34	0	23	22	0	460
2022	5	224	6	33	2	7	3	2	1	16	5	0	14	41	0	4	49	3	28	26	0	469
2023	6	136	0	12	0	1	14	7	1	10	5	2	1	14	0	3	31	0	16	26	0	285
2024	4	66	0	8	0	4	5	2	0	3	2	1	5	20	0	0	17	2	13	13	0	165
2025	3	65	1	6	3	0	0	0	0	20	5	0	0	22	0	0	18	0	6	0	0	149
2026	4	19	0	0	7	1	0	1	0	0	0	0	1	0	0	0	0	0	14	0	0	47
2027	0	18	0	3	1	0	0	2	2	0	0	0	0	0	0	0	1	0	26	0	0	53
2028	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	2	0	0	3
2029	0	0	0	0	4	0	0	0	0	0	0	0	0	0	0	0	0	0	2	0	0	6
2030	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	1
2031	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
2032	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2033	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2034	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	1
2035	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2036	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2037	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2038	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2039	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2040	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	94	1,386	106	241	49	221	36	107	58	283	161	37	59	187	5	37	215	16	267	330	0	3,895

Table 12-49 shows the latest cost estimate of supplemental projects by expected in service year for each transmission zone. The average cost of supplemental projects in each expected in service year increased by 2,312.9 percent, from $65.0 million for years 1998 through 2007 (pre Order No. 890) to $1,568.4 million for years 2008 through 2021 (post Order No. 890).

Table 12-49 Latest cost estimate by expected in service year and zone ($ millions): 1998 through 2040

Year	ACEC	AEP	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	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	$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	$0.77	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.77
2000	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$32.94	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$32.94
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	$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	$0.00	$0.00	$7.00
2003	$8.32	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$8.77	$0.00	$0.00	$0.00	$0.00	$0.00	$9.60	$0.00	$0.00	$0.00	$0.00	$26.69
2004	$4.45	$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	$0.00	$0.00	$22.58
2005	$4.06	$14.66	$10.11	$0.00	$0.00	$2.57	$0.00	$0.00	$0.00	$0.02	$10.98	$0.00	$0.00	$0.00	$0.00	$0.50	$0.00	$0.00	$0.00	$0.00	$0.00	$42.90
2006	$4.03	$309.70	$0.93	$0.00	$0.00	$48.92	$0.00	$0.00	$0.00	$0.00	$11.62	$0.00	$6.00	$0.00	$0.00	$0.00	$1.50	$0.00	$4.63	$18.80	$0.00	$406.13
2007	$1.12	$2.06	$9.85	$0.00	$37.61	$4.65	$0.00	$0.00	$31.75	$0.00	$12.93	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.34	$2.28	$0.00	$102.59
2008	$2.84	$0.00	$12.03	$0.00	$0.45	$7.61	$0.00	$0.00	$7.00	$14.01	$2.77	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$1.59	$0.00	$0.00	$48.30
2009	$0.77	$0.90	$12.22	$0.00	$5.00	$21.11	$0.00	$0.00	$19.60	$2.12	$7.35	$0.00	$0.00	$0.00	$0.00	$48.10	$2.73	$0.00	$0.16	$17.60	$0.00	$137.66
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	$0.00	$31.80	$0.00	$0.00	$1.86	$17.72	$0.00	$172.19
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	$0.00	$113.30	$0.00	$0.00	$11.87	$34.60	$0.00	$311.22
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	$0.00	$12.60	$0.00	$0.00	$19.66	$223.01	$0.00	$532.54
2013	$3.15	$134.93	$1.10	$33.68	$0.00	$59.25	$0.00	$9.93	$79.10	$25.03	$0.99	$0.00	$0.05	$4.10	$0.00	$22.50	$0.00	$2.40	$76.70	$503.72	$0.00	$956.63
2014	$15.53	$568.00	$5.97	$58.70	$21.20	$60.37	$0.00	$2.43	$14.90	$88.61	$5.95	$0.38	$5.60	$0.00	$0.00	$13.30	$1.30	$0.00	$33.47	$401.11	$0.00	$1,296.82
2015	$3.73	$237.67	$3.80	$21.90	$2.00	$376.00	$0.00	$14.12	$4.53	$113.53	$13.06	$1.56	$0.30	$0.00	$0.00	$33.80	$0.00	$42.50	$50.17	$743.91	$0.00	$1,662.58
2016	$74.54	$84.13	$18.40	$182.70	$0.00	$308.15	$0.00	$15.13	$26.95	$40.68	$26.60	$0.25	$0.00	$2.37	$0.00	$86.40	$0.40	$7.80	$59.20	$744.18	$0.00	$1,677.88
2017	$66.28	$648.74	$8.60	$164.45	$0.09	$145.97	$0.00	$64.31	$3.62	$104.25	$92.29	$2.21	$0.00	$14.70	$0.00	$0.00	$8.30	$12.00	$264.88	$994.43	$0.00	$2,595.12
2018	$66.55	$817.94	$14.60	$42.12	$4.08	$80.94	$0.00	$69.80	$3.13	$162.94	$68.94	$10.87	$0.00	$0.00	$0.00	$47.60	$0.00	$156.00	$197.34	$631.25	$0.00	$2,374.10
2019	$64.30	$1,158.43	$11.97	$190.40	$150.25	$90.19	$0.30	$98.59	$0.30	$90.14	$33.55	$23.67	$0.90	$62.30	$0.00	$2.00	$75.80	$0.00	$298.00	$356.41	$0.00	$2,707.50
2020	$59.58	$992.86	$0.30	$112.78	$65.81	$78.09	$13.66	$71.54	$7.20	$253.38	$39.50	$25.61	$2.60	$23.70	$0.00	$1.60	$74.50	$102.70	$196.99	$1,884.38	$0.00	$4,006.78
2021	$17.60	$1,524.74	$2.70	$238.08	$29.70	$137.80	$31.40	$173.00	$18.10	$75.77	$6.70	$29.18	$39.00	$194.30	$4.40	$31.70	$148.39	$0.00	$254.43	$520.75	$0.00	$3,477.74
2022	$186.66	$1,660.06	$7.48	$269.92	$244.30	$98.40	$10.35	$21.46	$45.00	$217.70	$67.90	$0.00	$48.50	$105.76	$0.00	$0.00	$114.30	$737.50	$362.25	$934.55	$0.00	$5,132.09
2023	$88.30	$1,402.18	$0.00	$141.06	$0.00	$1.00	$54.15	$54.79	$0.00	$56.80	$39.50	$20.49	$6.80	$80.80	$0.00	$201.80	$40.70	$0.00	$253.44	$855.60	$0.00	$3,297.41
2024	$38.74	$753.76	$0.00	$107.50	$0.00	$212.40	$61.60	$17.64	$0.00	$42.42	$39.70	$15.42	$38.50	$147.90	$0.00	$0.00	$24.50	$38.50	$237.10	$292.50	$0.00	$2,068.18
2025	$30.39	$515.60	$60.00	$199.70	$144.10	$0.00	$0.00	$0.00	$0.00	$267.77	$51.93	$0.00	$0.00	$134.70	$0.00	$0.00	$46.60	$0.00	$127.00	$0.00	$0.00	$1,577.79
2026	$64.00	$201.10	$0.00	$0.00	$336.00	$67.00	$0.00	$4.70	$0.00	$0.00	$0.00	$0.00	$16.00	$0.00	$0.00	$0.00	$0.00	$0.00	$387.05	$0.00	$0.00	$1,075.85
2027	$0.00	$250.20	$0.00	$389.30	$118.00	$0.00	$0.00	$32.57	$160.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$138.00	$0.00	$582.41	$0.00	$0.00	$1,670.48
2028	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$30.40	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$51.00	$0.00	$0.00	$81.40
2029	$0.00	$0.00	$0.00	$0.00	$231.00	$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	$96.60	$0.00	$0.00	$327.60
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	$0.00	$91.90	$0.00	$0.00	$91.90
2031	$0.00	$0.00	$0.00	$80.00	$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	$80.00
2032	$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	$0.00	$0.00
2033	$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	$0.00	$0.00
2034	$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	$200.00	$0.00	$0.00	$0.00	$0.00	$200.00
2035	$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	$0.00	$0.00
2036	$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	$0.00	$0.00
2037	$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	$0.00	$0.00
2038	$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	$0.00	$0.00
2039	$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	$0.00	$0.00
2040	$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	$0.00	$0.00
Total	$804.94	$11,395.62	$216.60	$2,232.64	$1,410.69	$1,816.22	$171.46	$676.07	$514.35	$1,821.56	$598.51	$129.64	$172.05	$775.21	$4.40	$647.00	$886.62	$1,099.40	$3,660.04	$9,176.80	$0.00	$38,209.82

The MMU recommends, to increase the role of competition, that the exemption of supplemental from the Order No. 1000 competitive process be terminated.

End of Life Transmission Projects

An end of life transmission project is a project submitted for the purpose of replacing existing infrastructure that is at, or is approaching, the end of its useful life. Under the current process, end of life transmission projects are not subject to the RTEP open window process and have become a form of supplemental project that is exempt from competition under the existing rules.[53]

The MMU recommends, to increase the role of competition, that the exemption of end of life projects from the Order No. 1000 competitive process be terminated and that end of life transmission projects be included in the RTEP process and should be subject to a transparent, robust and clearly defined mechanism to permit competition to build such projects.

Competitive Planning Process Exclusions

There are several project types that are currently exempt from the competitive planning process. These project 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 defined to be infeasible and such projects are excluded from competition. As a result, the local Transmission Owner is the Designated Entity.[54] On October 17, 2019, the Commission issued an Order Instituting Section 206 Proceedings to determine if RTOs have implemented the exemption in a manner consistent with the Commission's directives under Order 1000.[55] Some supplemental projects are in this category.
- **Below 200kV.** Due to the lower voltage level of the identified violation(s), the driver(s) for this project are excluded from competition. As a result, the local Transmission Owner is the Designated Entity.[56] Some supplemental projects are in this category.
- **Substation Equipment.** Due to identification of the limiting element(s) as substation equipment, such projects are excluded from competition. As a result, the local Transmission Owner is the Designated Entity.[57] Some supplemental projects are in this category.

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 for any of these exclusion categories.

Comparative Cost Framework

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. On May 24, 2018, the PJM Markets and Reliability Committee (MRC) approved a motion that required PJM, with input from the MMU, to develop a comparative cost framework to evaluate the quality and effectiveness of binding cost containment proposals versus proposals without cost containment provisions. On March 20, 2020, the Commission approved PJM's filing to amend the PJM Operating Agreement to incorporate this requirement.[58]

The 2020 RTEP Window 1 was the first open window that received cost capping proposals to be evaluated under the comparative cost framework. The analysis performed under the new process was insufficient and did not follow the process defined in the PJM manual.[59] The existing proposal templates do not provide enough information to adequately perform a financial analysis. The MMU recommends that PJM modify the project proposal templates to

53 In recent decisions addressing competing proposals on end of life projects, the Commission accepted a transmission owner proposal excluding end of life projects from competition in the RTEP process, 172 FERC ¶ 61,136 (2020), *reh'g denied*, 173 FERC ¶ 61,225 (2020), and rejected a proposal from PJM stakeholders that would have included end of life projects in competition in the RTEP process, 173 FERC ¶ 61,242 (2020).
54 See OA Schedule 6 § 1.5.8(m).
55 169 FERC ¶ 61,054 (2019).
56 See OA Schedule 6 § 1.5.8(n).
57 See OA Schedule 6 § 1.5.8(p).
58 170 FERC ¶ 61,243 (2020).
59 See PJM. "PJM Manual 14F: Competitive Planning Process," Rev. 5 (April 10, 2020).

include data necessary to perform a detailed project lifetime financial analysis. The required data includes, but is not limited to: capital expenditure; capital structure; return on equity; cost of debt; tax assumptions; ongoing capital expenditures; ongoing maintenance; and expected life.

Storage As A Transmission Asset (SATA)

The PJM Planning Committee is currently considering whether storage devices should be included in the RTEP process as transmission assets.[60]

Transmission and generation have, and have always had, a symbiotic relationship in the provision of wholesale power. Transmission needs generation to function and generation needs transmission to function. Transmission can substitute for generation at the margin and generation can substitute for transmission at the margin. This relationship has always been a relatively unexamined area in the design of competitive wholesale power markets. For example, there is little if any explicit consideration of the impact of transmission planning on competitive generation investment in RTO/ISO market rules. Improvement is needed in these areas. Introducing confusion about what assets are classified as generation and what assets are classified as transmission frustrates potential reform and undermines the competitive markets.

On July 22, 2020, through the supplemental planning process, American Electric Power Service Corporation (AEP) filed, on behalf of Kentucky Power Company (Kentucky Power), a Petition for Declaratory Order seeking confirmation that its Middle Creek energy storage project is eligible for cost-of-service recovery through AEP's formula rates.[61] AEP's Middle Creek energy storage project was a proposed battery storage device that would discharge energy to serve retail load at the Middle Creek substation in the event of a transmission outage. On December 21, 2020, the Commission ruled that the Middle Creek energy storage project did not perform a transmission function, and was ineligible to recover its costs through formula rates.[62]

Storage devices like batteries that are defined to be part of PJM markets should not be treated as transmission assets. The MMU recommends that storage resources not be includable as transmission assets for any reason.

Board Authorized Transmission Upgrades

The Transmission Expansion Advisory Committee (TEAC) regularly reviews internal and external proposals to improve transmission reliability throughout PJM. These proposals, which include reliability baseline, network, market efficiency and targeted market efficiency projects, as well as scope changes and project cancellations, but exclude supplemental and end of life projects, are periodically presented to the PJM Board of Managers for authorization.[63]

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.

In the first three months of 2021, the PJM Board approved a net change of $349.8 million in transmission upgrades. As of March 31, 2021, the PJM Board had approved $38.2 billion in transmission system enhancements since 1999. On February 22, 2021, the PJM Board of Managers authorized an additional $349.8 million in transmission upgrades and additions.

Qualifying Transmission Upgrades (QTU)

A Qualifying Transmission Upgrade (QTU) is an upgrade to the transmission system that increases the Capacity Emergency Transfer Limit (CETL) into an LDA and can be offered into capacity auctions as capacity. Once a QTU is in service, the upgrade is eligible to continue to offer the approved incremental import capability into future RPM Auctions.

If a QTU that was cleared in a Base Residual Auction (BRA) or Incremental Auction (IA) is not completed by the start of the Delivery Year, the submitting

60 See PJM. "*Storage As A Transmission Asset: Problem / Opportunity Statement*," <https://pjm.com/-/media/committees-groups/committees/pc/2020/20200605-special/20200605-item-02a-storage-as-a-transmission-asset-problem-statement-clean.ashx>.

61 See AEP, Docket No. EL20-58 (July 22, 2020).

62 173 FERC ¶ 61,264 (2020).

63 Supplemental Projects, including the end of life subset of supplemental projects, do not require PJM Board of Managers authorization.

party is required to provide replacement capacity. Once a QTU is in service, the upgrade is eligible to continue to offer the approved incremental import capability into future RPM Auctions. As of March 31, 2021, no QTUs have cleared a BRA or IA.

Cost Allocation

In response to complaints against PJM RTEP Baseline Upgrade Filings in 2014 that included cost allocations for $1.5 billion in baseline transmission enhancements and expansions, on November 24, 2015, FERC issued an order directing investigation of "whether there is a definable category of reliability projects within PJM for which the solution-based DFAX cost allocation method may not be just and reasonable, such as projects addressing reliability violations that are not related to flow on the planned transmission facility, and whether an alternative just and reasonable *ex ante* cost allocation method could be established for any such category of projects."[64] FERC convened a technical conference on January 12, 2016, to address the complaints in multiple proceedings and to address these two core issues.[65]

The issues identified in the complaints and at the technical conference included: whether the solutions based allocation method is appropriate for upgrades not related to transmission overload issues; whether the solutions based allocation method correctly identifies all the beneficiaries of the upgrades; whether it is reasonable to allocate a level of costs to a merchant transmission project that could force bankruptcy; and whether the significant shifts in allocation that result from use of the 0.01 distribution factor cutoff are appropriate.

On February 20, 2020, the Commission issued an Order denying rehearing requests.[66] The Commission found that PJM's solution based dfax method for regional cost allocation, including the 0.01 distribution cutoff factor, is just and reasonable.

It is clear that the allocation issues are difficult. Nonetheless, the allocation methods affect the efficiency of the markets and the incentives for merchant transmission owners to compete to build new transmission. The MMU recommends a comprehensive review of the ways in which the solution based dfax is implemented. The goal for such a process would be to ensure that the most rational and efficient approach to implementing the solution based dfax method is used in PJM. Such an approach should allocate costs consistent with benefits and appropriately calibrate the incentives for investment in new transmission capability. No replacement approach should be approved until all potential alternatives, including the status quo, are thoroughly reviewed.

As an example, the use of the arbitrary 0.01 distribution factor cutoff can result in large and inappropriate shifts in cost allocation. If the intent of the use of the 0.01 cutoff is to help eliminate small, arbitrary cost allocations to geographically distant areas, this could be achieved by adding a threshold for a minimum usage impact on the line. The MMU recommends consideration of changing the minimum distribution factor in the allocation from 0.01 to 0.00 and adding a threshold minimum impact on the load on the line based on a complete analysis of the intent of the allocation and the impacts of the allocation.

Transmission Line Ratings

Transmission line ratings, and more broadly transmission facility ratings, are the metric for the ability of transmission lines to transmit power from one point to another. Transmission line ratings have significant and frequently underappreciated impacts on competitive wholesale power markets like PJM. These include direct impacts on energy and capacity prices, the frequency and level of congestion in the day-ahead and real-time energy market, day-ahead nodal price differences and the associated value of FTRs, locational price differences in the capacity market, the need to invest in additional transmission capacity, the need to invest in additional generation capacity, the location of new power plants, and the interconnection costs for new power plants. The impact of transmission facility ratings on markets is a function both of the line ratings directly and the use of those ratings by the RTO/ISO.

64 153 FERC ¶ 61,245 at P 35 (2015).
65 See Docket Nos. EL15-18-000 (ConEd), EL15-67-000 (Linden), and EL15-95-000 (Artificial Island).
66 170 FERC ¶ 61,122 (2020).

Congestion payments by load result when lower cost generation is not available to meet all the load in an area as a result of limits on the transmission system. When higher cost local generation is needed to meet part of the local load because of transmission limits, 100 percent of the local load pays the higher price while only the local generation receives the higher price. The difference between what the load pays and generators receive is congestion. Since 2008, congestion costs in PJM have ranged from $0.5 billion to $2.05 billion per year. Congestion costs were significantly higher during extreme winter weather conditions such as January 2014, when the congestion costs in PJM were $825.1 million for one month.[67]

LMP may, at times, be set by transmission penalty factors. When a transmission constraint is binding and there are no generation alternatives to resolve the constraint, system operators may allow the transmission limit to be violated. When this occurs, the shadow price of the constraint is set by transmission penalty factors. The shadow price directly affects the LMP. Transmission penalty factors are administratively determined and can be thought of as a form of locational scarcity pricing. Transmission penalty factors were fully implemented in PJM pricing effective February 1, 2019.

Transmission line ratings can result in short term, significant increases in prices as a result of the application of transmission penalty factors. For example, violation of a transmission constraint, meaning that the flow exceeds the line limit, could result in a $2,000 per MWh price. As the power flows approach their rated limits, PJM dispatchers may reduce the limits.[68] Violation of these reduced line ratings results in penalty factors setting prices. In 2019, there were 152,675 transmission constraint intervals in the real-time market with a non-zero shadow price. For nearly five percent of these transmission constraints, the line limit was violated, meaning the flow exceeded the facility limit and prices were set by transmission penalty factors. In 2019, the average shadow price of transmission constraints when the line limit was violated was nearly 15 times higher than when transmission constraint was binding at its limit.[69]

Capacity market prices separate locally when transmission capability into Locational Deliverable Areas (LDA) is not adequate to meet the LDA capacity requirement with the lowest cost capacity. The available transmission capability into LDAs is defined as the Capacity Emergency Transfer Limit (CETL). Higher cost LDAs are the equivalent in the capacity market of congestion in the energy market. Load in the higher cost LDAs pay more for capacity than those in lower cost LDAs. For example, the clearing price for the BGE LDA in the 2021/2022 Base Residual Auction was $200.30 per MW-day. The clearing price for the EMAAC LDA was $165.73 per MW-day.[70]

Transmission line ratings for a given transmission facility vary by the duration of the power flow, by ambient temperatures, by wind speed and by other conditions. Transmission lines can operate with higher loads for shorter periods of time. This is significant when a contingency is expected to last for only a short period. The transmission line rating can mean the difference between substantial congestion costs and no congestion costs. The transmission line rating can mean the difference between a transmission penalty factor and no penalty factor.

In PJM, transmission owners use a range of ratings by duration.[71] PJM requires transmission owners to provide thermal ratings under normal operating conditions, long term emergency operating conditions, short term emergency operating conditions and the extreme load dump conditions. But there is no requirement that the ratings differ for these operating conditions. PJM typically uses normal line ratings for precontingency (base case) constraints and long term emergency line ratings (four hours) for contingency constraints. PJM requires transmission owners to provide temperature based line ratings separately for night and day times. The temperature ranges from 32 degree Fahrenheit or below to 95 degree Fahrenheit or above in nine degree increments. But there is no requirement that the ratings differ

67 See the *2018 State of the Market Report for PJM*, Volume II, Section 11: Congestion and Marginal Losses.
68 See "Transmission Constraint Control Logic and Penalty Factors," presented at May 10, 2018 meeting of the Markets Implementation Committee Special Session Transmission Constraint Penalty Factors at p14. <https://www.pjm.com/-/media/committees-groups/committees/mic/20180510-special/20180510-item-03-transmission-constraint-penalty-factor-education.ashx>.
69 See the *2019 State of the Market Report for PJM*, Volume II, Section 3: Energy Market.
70 See the "Analysis of the 2021/2022 RPM Base Residual Auction," <https://www.monitoringanalytics.com/reports/Reports/2018/IMM_Analysis_of_the_20212022_RPM_BRA_Revised_20180824.pdf> (August 24, 2018).
71 See "PJM Manual 3: Transmission Operations," Rev. 58 (November 19, 2020) § 2.1.1, at p 28.

for these operating condition temperatures. In PJM, transmission owners are responsible for developing their own methods to compute line ratings subject to a range of NERC guidelines and requirements. PJM does not review or verify the accuracy of transmission owners' methods to compute line ratings. In PJM, transmission owners have substantial discretion in the approach to line ratings.[72]

Given the significant impact of transmission line ratings on all aspects of wholesale power markets, ensuring and improving the accuracy and transparency of line ratings is essential. Line ratings should incorporate ambient temperature conditions, wind speed and other relevant operating conditions. PJM real-time prices are calculated every five minutes for thousands of nodes. PJM prices are extremely sensitive to transmission line ratings. For consistency with the dynamic nature of wholesale power markets, line ratings should be updated in real time to reflect real time conditions and to help ensure that real-time prices are based on actual current line ratings. The ongoing analysis of dynamic line ratings is a promising area that should be pursued.

The MMU recommends that all PJM transmission owners use the same methods to define line ratings, subject to NERC standards and guidelines, subject to review by NERC and approval by FERC. The same facilities should have the same basic ratings under the same operating conditions regardless of the transmission owner. Transmission owner discretion should be minimized or eliminated. The line rating methods should be based on the basic engineering facts of the transmission system components and reflect the impact of actual operating conditions on the ratings of transmission facilities, including ambient temperatures and wind speed when relevant.[73] The line rating methods should be public and fully transparent.

The MMU recommends that PJM routinely review all transmission facility ratings and any changes to those ratings to ensure that the normal, emergency and load dump ratings used in modeling the transmission system are accurate and reflect standard ratings practice.[74] All line rating changes and the detailed reasons for those changes should be public and fully transparent.

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.[75] When a reportable transmission facility needs to be taken out of service, the transmission owner is required to submit an outage request as early as possible.[76] The specific timeline is shown in Table 12-51.[77]

Transmission outages have significant impacts on PJM markets, including impacts on FTR auctions, on congestion, and on expected market outcomes in the day-ahead and real-time markets. The efficient functioning of the markets depends on clear, enforceable rules governing transmission outages.

The outage data for the FTR market are for outages scheduled to occur in the 2019/2020 planning period and the first 10 months of the 2020/2021 planning period, regardless of when they were initially submitted.[78] The outage data for the day-ahead market are for outages scheduled to occur from January 2015 through March 2021.

Transmission outages are categorized by duration: greater than 30 calendar days; less than or equal to 30 calendar days; greater than five calendar days; less than or equal to five calendar days.[79] Table 12-50 shows that 77.2 percent of requested outages were planned for less than or equal to five days and 8.4 percent of requested outages were planned for greater than 30 days in the first t10 months of the 2020/2021 planning period. Table 12-50 also shows that

72 PJM presentation to the Planning Committee (PC) (May 3, 2018) "Transmission Owner Ratings Development and Reporting in PJM" ("There are no requirements for PJM to approve or verify a TO's ratings or do any kind of consistency check.") at 24.

73 *See* "Transmission Owner Ratings Development and Reporting in PJM," presented at May 3, 2018 meeting of the Planning Committee. <https://www.pjm.com/-/media/committees-groups/committees/pc/20180503/20180503-item-13-to-ratings-process-and-reporting.ashx>.

74 *See* the *2018 State of the Market Report for PJM*, Volume II, Section 2: Recommendations.

75 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 3: Transmission Operations," Rev. 58 (November 19, 2020).

76 See PJM, "Manual 3: Transmission Operations," Rev. 58 (November 19, 2020).

77 See PJM, "Manual 3: Transmission Operations," Rev. 58 (November 19, 2020).

78 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.

79 *Id.* at 70.

77.8 percent of the requested outages were planned for less than or equal to five days and 7.8 percent of requested outages were planned for greater than 30 days in the 2019/2020 planning period.

Table 12-50 Transmission facility outage request summary by planned duration: June 2019 through March 2021

	2019/2020 (12 months)		2020/2021 (10 months)	
Planned Duration (Days)	Outage Requests	Percent of Total	Outage Requests	Percent of Total
<=5	16,609	77.8%	12,765	77.2%
>5 & <=30	3,077	14.4%	2,383	14.4%
>30	1,676	7.8%	1,394	8.4%
Total	21,362	100.0%	16,542	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 12-51.[80]

The purpose of the rules defined in Table 12-51 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 PJM can accurately model market conditions.[81]

Table 12-51 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 12-52 shows a summary of requests by received status. In the first 10 months of the 2020/2021 planning period, 42.7 percent of outage requests received were late. In the 2019/2020 planning period, 44.4 percent of outage requests received were late.

Table 12-52 Transmission facility outage request summary by received status: June 2019 through March 2021

	2019/2020 (12 months)				2020/2021 (10 months)			
Planned Duration (Days)	On Time	Late	Total	Percent Late	On Time	Late	Total	Percent Late
<=5	9,570	7,039	16,609	42.4%	7,618	5,147	12,765	40.3%
>5 & <=30	1,640	1,437	3,077	46.7%	1,280	1,103	2,383	46.3%
>30	663	1,013	1,676	60.4%	580	814	1,394	58.4%
Total	11,873	9,489	21,362	44.4%	9,478	7,064	16,542	42.7%

Once received, PJM processes outage requests in priority order: emergency transmission outage request; transmission outage request submitted on time; and transmission outage request submitted late. Transmission outage requests that are submitted late may be approved if the outage does not affect the reliability of PJM or cause congestion in the system.[82]

80 See PJM, "Manual 3: Transmission Operations," Rev. 58 (Nov. 19, 2020).
81 See "*Report of PJM Interconnection, L.L.C. on Transmission Oversight Procedures*," Docket No. EL01-122-000 (November 2, 2001).
82 See PJM, "Manual 3: Transmission Operations," Rev. 58 (Nov. 19, 2020). The following language was removed from Manual 3 Rev. 50: PJM retains the right to deny all jobs submitted after 8 a.m. three days prior to the requested start date unless the request is an emergency job or an exception request (i.e. a generator tripped and the Transmission Owner is taking advantage of a situation that was not available before the unit trip).

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.[83] Table 12-53 is a summary of outage requests by emergency status. Of all outage requests scheduled to occur in the first 10 months of the 2020/2021 planning period, 12.7 percent were for emergency outages. Of all outage requests scheduled to occur in the 2019/2020 planning period, 12.2 percent were for emergency outages.

Table 12-53 Transmission facility outage request summary by emergency: June 2019 through March 2021

	2019/2020 (12 months)				2020/2021 (10 months)			
Planned Duration (Days)	Emergency	Non Emergency	Total	Percent Emergency	Emergency	Non Emergency	Total	Percent Emergency
<=5	1,952	14,657	16,609	11.8%	1,520	11,245	12,765	11.9%
>5 &t <=30	402	2,675	3,077	13.1%	372	2,011	2,383	15.6%
>30	262	1,414	1,676	15.6%	213	1,181	1,394	15.3%
Total	2,616	18,746	21,362	12.2%	2,105	14,437	16,542	12.7%

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."[84]

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 12-54 is a summary of outage requests by congestion status. Of all outage requests submitted to occur in the first 10 months of the 2020/2021 planning period, 6.3 percent were expected to cause congestion. Of all the outage requests that were expected to cause congestion, 2.0 percent (21 out of 1,045) were denied by PJM in the first 10 months of the 2020/2021 planning period and 19.8 percent (207 out of 1,045) were cancelled (Table 12-56). Of all outage requests submitted to occur in the 2019/2020 planning period, 6.5 percent were expected to cause congestion. Of all the outage requests that were expected to cause congestion, 2.1 percent (29 out of 1,399) were denied by PJM in the 2019/2020 planning period and 21.7 percent (304 out of 1,399) were cancelled (Table 12-56).

Table 12-54 Transmission facility outage request summary by congestion: June 2019 through March 2021

	2019/2020 (12 months)				2020/2021 (10 months)			
Planned Duration (Days)	Congestion Expected	No Congestion Expected	Total	Percent Congestion Expected	Congestion Expected	No Congestion Expected	Total	Percent Congestion Expected
<=5	976	15,633	16,609	5.9%	749	12,016	12,765	5.9%
>5 &t <=30	267	2,810	3,077	8.7%	198	2,185	2,383	8.3%
>30	156	1,520	1,676	9.3%	98	1,296	1,394	7.0%
Total	1,399	19,963	21,362	6.5%	1,045	15,497	16,542	6.3%

83 PJM, "Manual 3: Transmission Operations," Rev. 58 (Nov. 19, 2020).
84 PJM added this definition to Manual 38 in February 2017. PJM, "Manual 38: Operations Planning," Rev. 14 (Jan. 27, 2021).

Table 12-55 shows the outage requests summary by received status, congestion status and emergency status. In the first 10 months of the 2020/2021 planning period, 30.1 percent of requests were submitted late and were nonemergency while 1.1 percent of requests (178 out of 16,542) were late, nonemergency, and expected to cause congestion. In the 2019/2020 planning period, 32.3 percent of request were submitted late and were nonemergency while 1.1 percent of requests (238 out of 21,362) were late, nonemergency, and expected to cause congestion.

Table 12-55 Transmission facility outage request summary by received status, emergency and congestion: June 2019 through March 2021

		2019/2020 (12 months)				2020/2021 (10 months)			
Received Status		Congestion Expected	No Congestion Expected	Total	Percent of Total	Congestion Expected	No Congestion Expected	Total	Percent of Total
Late	Emergency	68	2,517	2,585	12.1%	63	2,015	2,078	12.6%
	Non Emergency	238	6,666	6,904	32.3%	178	4,808	4,986	30.1%
On Time	Emergency	4	27	31	0.1%	1	26	27	0.2%
	Non Emergency	1,089	10,753	11,842	55.4%	803	8,648	9,451	57.1%
Total		1,399	19,963	21,362	100.0%	1,045	15,497	16,542	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.[85] Table 12-56 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 12-56. Table 12-56 shows that of all the outage requests that were expected to cause congestion, 2.0 percent (21 out of 1,045) were denied by PJM in the first 10 months of the 2020/2021 planning period, 67.1 percent were complete and 19.8 percent (207 out of 1,045) were cancelled. Of all the outage requests that were expected to cause congestion, 2.1 percent (29 out of 1,399) were denied by PJM in the 2019/2020 planning period, 70.0 percent were complete and 21.7 percent (304 out of 1,399) were cancelled.

Table 12-56 Transmission facility outage requests status summary: June 2019 through March 2021

		2019/2020 (12 months)						2020/2021 (10 months)					
Received Status		Cancelled	Complete	In Process	Denied	Congestion Expected	Percent Complete	Cancelled	Complete	In Process	Denied	Congestion Expected	Percent Complete
Late	Emergency	6	61	0	1	68	89.7%	4	57	1	1	63	90.5%
	Non Emergency	37	185	7	8	238	77.7%	33	121	14	8	178	68.0%
On Time	Emergency	1	3	0	0	4	75.0%	0	0	1	0	1	0.0%
	Non Emergency	260	730	77	20	1,089	67.0%	170	523	86	12	803	65.1%
Total		304	979	84	29	1,399	70.0%	207	701	102	21	1,045	67.1%

There are clear rules defined for assigning On Time or Late status for submitted outage requests in both the PJM tariff and PJM manuals.[86] However, the On Time or Late status only affects the priority that PJM assigns for processing the outage request. Table 12-56 shows that in the 2019/2020 planning period, 238 nonemergency outage requests were submitted late and expected to cause congestion. The expected impact on congestion is the basis for PJM's treatment of

85 See PJM Markets & Operations, PJM Tools "Outage Information," <http://www.pjm.com/markets-and-operations/etools/oasis/system-information/outage-info.aspx> (2019).
86 OA Schedule 1 § 1.9.2.

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.

Rescheduling Transmission Facility Outage Requests

A TO can reschedule or cancel an outage after initial submission. Table 12-57 is a summary of all the outage requests planned for the 2019/2020 planning period and the first 10 months of the 2020/2021 planning period 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 first 10 months of the 2020/2021 planning period, 29.7 percent of transmission outage requests were approved by PJM and then rescheduled by the TOs, and 12.0 percent of the transmission outages were approved by PJM and subsequently cancelled by the TOs. In the 2019/2020 planning period, 31.8 percent of transmission outage requests were approved by PJM and then rescheduled by the TO, and 11.4 percent of the transmission outages were approved by PJM and subsequently cancelled by the TO.

Table 12-57 Rescheduled and cancelled transmission outage request summary: June 2019 through March 2021

	2019/2020 (12 months)					2020/2021 (10 months)				
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	16,609	3,879	23.4%	2,163	13.0%	12,765	2,821	22.1%	1,758	13.8%
>5 &t <=30	3,077	1,826	59.3%	188	6.1%	2,383	1,302	54.6%	152	6.4%
>30	1,676	1,095	65.3%	81	4.8%	1,394	793	56.9%	68	4.9%
Total	21,362	6,800	31.8%	2,432	11.4%	16,542	4,916	29.7%	1,978	12.0%

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.[87] 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.[88] 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 six months prior to the month in which the outage was expected to occur. The rescheduling rule allows TOs to avoid the timing requirements associated with outages exceeding five days.

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.

87 PJM, "Manual 3: Transmission Operations," Rev. 58 (Nov. 19, 2020).
88 *Id.*

Long Duration Transmission Facility Outage Requests

PJM rules (Table 12-51) 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.

More than one outage request can be submitted for the same transmission equipment. In order to accurately present the results, Table 12-58 shows equipment outages by the equipment instead of by outage request.

Table 12-58 shows that there were 10,728 transmission equipment planned outages in the first 10 months of the 2020/2021 planning period, of which 1,395 or 13.0 percent were longer than 30 days, and of which 169 or 1.6 percent were scheduled longer than 30 days when the duration of all the outage requests are combined for the same equipment.

Table 12-58 Transmission equipment outage summary: June 2019 through March 2021

		2019/2020 (12 months)		2020/2021 (10 months)	
Planned Duration (Days)	Divided into Shorter Periods	Count of Equipment with Planned Outages	Percent of Total	Count of Equipment with Planned Outages	Percent of Total
> 30	No	1,474	11.2%	1,226	11.4%
	Yes	229	1.7%	169	1.6%
<= 30		11,427	87.0%	9,333	87.0%
Total		13,130	100.0%	10,728	100.0%

Table 12-59 shows the details of long duration (> 30 days) outages when combining the duration of the outage requests for the same equipment.[89] The actual duration of scheduled outages would be longer than 30 days if the duration of the outage requests was appropriately combined for the same equipment. An effective duration was calculated for each piece of equipment by subtracting the start date of the earliest outage request from the end date of the latest outage request of the equipment. In the first 10 months of the 2020/2021 planning period, within effective duration greater than a month and shorter than two months, there were 24 outages with a combined duration longer than 30 days.

89 A transmission facility is modeled as equipment in the EMS model. Equipment has three identifiers: location (B1), voltage level (B2) and equipment name (B3). The types of equipment include, for example, lines, transformers, and capacitors. There can be multiple outage requests associated with the same equipment.

Table 12-59 Transmission equipment outages by effective duration: June 2019 through March 2021

	2019/2020 (12 months)		2020/2021 (10 months)	
Effective Duration of Outage	Count of Equipment with Planned Outages	Percent of Total	Count of Equipment with Planned Outages	Percent of Total
<=31	3	1.3%	2	1.2%
>31 & <=62	27	11.8%	24	14.2%
>62 & <=93	21	9.2%	20	11.8%
>93	178	77.7%	123	72.8%
Total	229	100.0%	169	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 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 weeks as an initial list. Then PJM may exercise significant discretion in selecting outages to be modeled in the final model. PJM posts the final FTR outage list to the FTR web page usually at least one week before the auction bidding opening day.[90]

In the first 10 months of the 2020/2021 planning period, 310 outage requests were included in the annual FTR market outage list and 16,232 outage requests were not included.[91] In the 2019/2020 planning period, 289 outage requests were included in the annual FTR market outage list and 21,073 outage requests were not included. Table 12-60, Table 12-61, Table 12-62 and Table 12-63 show the summary information on the modeled outage requests and Table 12-64 and Table 12-65 show the summary information on outages that were not included in the Annual FTR Market.

Table 12-60 shows that 27.2 percent of the outage requests modeled in the Annual FTR Market for the first 10 months of the 2020/2021 planning period had a planned duration of less than two weeks and that 16.1 percent of the outage requests (50 out of 310) modeled in the Annual FTR Market for the planning period were submitted late according to outage submission rules. It also shows that 15.2 percent of the outage requests modeled in the Annual FTR Market for the 2019/2020 planning period had a planned duration of less than two weeks and that 17.0 percent of the outage requests (49 out of 289) modeled in the Annual FTR Market for the planning period were submitted late according to outage submission rules.

Table 12-60 Annual FTR market modeled transmission facility outage requests by received status: June 2019 through March 2021

	2019/2020 (12 months)				2020/2021 (10 months)			
Planned Duration	On Time	Late	Total	Percent of Total	On Time	Late	Total	Percent of Total
<2 weeks	35	9	44	15.2%	75	11	86	27.7%
>=2 weeks & <2 months	84	10	94	32.5%	80	13	93	30.0%
>=2 months	121	30	151	52.2%	105	26	131	42.3%
Total	240	49	289	100.0%	260	50	310	100.0%

90 PJM Financial Transmission Rights, "Annual ARR Allocation and FTR Auction Transmission Outage Modeling," <https://www.pjm.com/-/media/markets-ops/ftr/annual-ftr-auction/2018-2019/2018-2019-annual-outage-modeling.ashx?la=en> (April 5, 2018). There is no documentation on the deadline for when modeling outages should be posted on the PJM website.

91 PJM's treatment of transmission outages in the FTR models is discussed in the *2020 State of the Market Report for PJM*: Section 13: FTRs and ARRs: Supply and Demand.

Table 12-61 shows the annual FTR market modeled outage requests summary by emergency status and received status. Two of the annual FTR market modeled outages expected to occur in the first 10 months of the 2020/2021 planning period were emergency outages. Two of the modeled outages expected to occur in the 2019/2020 planning period were emergency outages.

Table 12-61 Annual FTR market modeled transmission facility outage requests by emergency and received status: June 2019 through March 2021

		2019/2020 (12 months)				2020/2021 (10 months)			
Received Status	Planned Duration	Emergency	Non Emergency	Total	Percent Non Emergency	Emergency	Non Emergency	Total	Percent Non Emergency
On Time	<2 weeks	0	35	35	100.0%	0	75	75	100.0%
	>=2 weeks & <2 months	0	84	84	100.0%	0	80	80	100.0%
	>=2 months	0	121	121	100.0%	0	105	105	100.0%
	Total	0	240	240	100.0%	0	260	260	100.0%
Late	<2 weeks	0	9	9	100.0%	2	9	11	81.8%
	>=2 weeks & <2 months	0	10	10	100.0%	0	13	13	100.0%
	>=2 months	2	28	30	93.3%	0	26	26	100.0%
	Total	2	47	49	95.9%	2	48	50	96.0%

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 12-62 shows a summary of requests by expected congestion and received status. Of all the annual FTR market modeled outages expected to occur in the first 10 months of the 2020/2021 planning period and submitted late, 8.0 (4 out of 50) was expected to cause congestion. Overall, of all the annual FTR market modeled outages expected to occur in the 2019/2020 planning period and submitted late, 10.2 percent (5 out of 49) were expected to cause congestion.

Table 12-62 Annual FTR market modeled transmission facility outage requests by congestion and received status: June 2019 through March 2021

		2019/2020 (12 months)				2020/2021 (10 months)			
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	11	24	35	31.4%	18	57	75	24.0%
	>=2 weeks & <2 months	24	60	84	28.6%	16	64	80	20.0%
	>=2 months	23	98	121	19.0%	19	86	105	18.1%
	Total	58	182	240	24.2%	53	207	260	20.4%
Late	<2 weeks	2	7	9	22.2%	2	9	11	18.2%
	>=2 weeks & <2 months	2	8	10	20.0%	1	12	13	7.7%
	>=2 months	1	29	30	3.3%	1	25	26	3.8%
	Total	5	44	49	10.2%	4	46	50	8.0%

Table 12-63 shows that 22.6 percent of outage requests modeled in the annual FTR market for the first 10 months of the 2020/2021 planning period and with a duration of two weeks or longer but shorter than two months were cancelled after the FTR auction was open, compared to 28.7 percent for the 2019/2020 planning period. Table 12-63 also shows that 17.6 percent of outages requests modeled in the Annual FTR Market for the first 10 months of the 2020/2021 planning period and with a duration of two months or longer were cancelled, compared to 22.5 percent for the 2019/2020 planning period.

Table 12-63 Annual FTR market modeled transmission facility outage requests by processed status: June 2019 through March 2021

		2019/2020 (12 months)		2020/2021 (10 months)	
Planned Duration	Processed Status	2019/2020	Percent	Outage Requests	Percent
<2 weeks	In Progress	7	15.9%	5	5.8%
	Denied	0	0.0%	1	1.2%
	Approved	0	0.0%	1	1.2%
	Cancelled	7	15.9%	26	30.2%
	Active	0	0.0%	0	0.0%
	Completed	30	68.2%	53	61.6%
	Total	44	100.0%	86	100.0%
>=2 weeks & <2 months	In Progress	15	16.0%	10	10.8%
	Denied	0	0.0%	0	0.0%
	Approved	0	0.0%	1	1.1%
	Cancelled	27	28.7%	21	22.6%
	Active	0	0.0%	1	1.1%
	Completed	52	55.3%	60	64.5%
	Total	94	100.0%	93	100.0%
>=2 months	In Progress	24	15.9%	17	13.0%
	Denied	0	0.0%	2	1.5%
	Approved	0	0.0%	1	0.8%
	Cancelled	34	22.5%	23	17.6%
	Active	4	2.6%	31	23.7%
	Completed	89	58.9%	57	43.5%
	Total	151	100.0%	131	100.0%
Total Cancelled		68	23.5%	70	22.6%
Grand Total		289		310	

More outage requests were not modeled in the Annual FTR Market than were modeled in the Annual FTR Market. In the first 10 months of the 2020/2021 planning period, 310 outage requests were modeled and 16,232 outage requests were not modeled in the Annual FTR Market. In the 2019/2020 planning period, 289 outage requests were modeled and 21,073 outage requests were not modeled in the Annual FTR Market.

Table 12-64 shows that 6.6 percent of outage requests not modeled in the Annual FTR Auction with duration longer than or equal to two months, labeled On Time according to the rules, were submitted or rescheduled after the Annual FTR Auction bidding opening date for the first 10 months of the 2020/2021 planning period compared to 15.3 percent in the 2019/2020 planning period.

Table 12-64 Transmission facility outage requests not modeled in Annual FTR Auction: June 2019 through March 2021

	2019/2020 (12 months)						2020/2021 (10 months)					
	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	1,684	8,696	83.8%	238	7,660	97.0%	1,902	6,257	76.7%	210	5,580	96.4%
>=2 weeks & <2 months	618	413	40.1%	150	823	84.6%	659	187	22.1%	132	649	83.1%
>=2 months	188	34	15.3%	221	348	61.2%	199	14	6.6%	185	258	58.2%
Total	2,490	9,143	78.6%	609	8,831	93.5%	2,760	6,458	70.1%	527	6,487	92.5%

Table 12-65 shows that 81.8 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 first 10 months of the 2020/2021 planning period. It also shows that 85.7 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 2019/2020 planning period.

Table 12-65 Late transmission facility outage requests: June 2019 through March 2021

	2019/2020 (12 months)			2020/2021 (10 months)		
Planned Duration	Completed Outages	Total	Percent Complete	Completed Outages	Total	Percent Complete
<2 weeks	6,593	7,660	86.1%	4,794	5,580	85.9%
>=2 weeks & <2 months	705	823	85.7%	531	649	81.8%
>=2 months	301	348	86.5%	152	258	58.9%
Total	7,599	8,831	86.0%	5,477	6,487	84.4%

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 those 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 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 less than or equal to five days. PJM exercises 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.[92] Table 12-66 and Table 12-67 show the summary information on outage requests modeled in the Monthly Balance of Planning Period FTR Auction and Table 12-68 and Table 12-69 show the summary information on outage requests not modeled in the Monthly Balance of Planning Period FTR Auction.

Table 12-66 shows that on average, 30.0 percent of the outage requests modeled in the Monthly Balance of Planning Period FTR Auction were submitted late according to outage submission rules in the first t10 months of the 2020/2021

92 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).

planning period. On average, 32.4 percent of the outage requests modeled in the Monthly Balance of Planning Period FTR Auction were submitted late according to outage submission rules in the 2019/2020 planning period.

Table 12-66 Monthly Balance of Planning Period FTR Auction modeled transmission facility outage requests by received status: June 2019 through March 2021

	2019/2020				2020/2021			
Month	On Time	Late	Total	Percent Late	On Time	Late	Total	Percent Late
Jun	162	115	277	41.5%	215	101	316	32.0%
Jul	92	96	188	51.1%	96	71	167	42.5%
Aug	131	86	217	39.6%	118	81	199	40.7%
Sep	379	147	526	27.9%	468	140	608	23.0%
Oct	533	183	716	25.6%	596	176	772	22.8%
Nov	431	163	594	27.4%	486	185	671	27.6%
Dec	311	146	457	31.9%	324	130	454	28.6%
Jan	189	86	275	31.3%	224	64	288	22.2%
Feb	223	93	316	29.4%	211	116	327	35.5%
Mar	428	141	569	24.8%	429	142	571	24.9%
Apr	461	181	642	28.2%				
May	391	167	558	29.9%				
Average	311	134	445	32.4%	317	121	437	30.0%

Table 12-67 shows that on average, 17.3 percent of outage requests modeled in the Monthly Balance of Planning Period FTR Auction were cancelled in the first 10 months of the 2020/2021 planning period. On average, 19.7 percent of outage requests modeled in the Monthly Balance of Planning Period FTR Auction were cancelled in the 2019/2020 planning period.

Table 12-67 Monthly Balance of Planning Period FTR Auction modeled transmission facility outage requests by processed status: June 2019 through March 2021

Planning Year	Month	In Process	Denied	Approved	Cancelled	Revised	Active	Complete	Total	Percent Cancelled
2019/2020	Jun	17	2	2	47	0	82	127	277	17.0%
	Jul	13	4	0	45	0	72	54	188	23.9%
	Aug	14	5	0	37	0	79	82	217	17.1%
	Sep	58	2	25	93	0	178	170	526	17.7%
	Oct	65	2	13	131	1	200	304	716	18.3%
	Nov	30	1	11	120	0	173	259	594	20.2%
	Dec	27	4	8	86	1	74	257	457	18.8%
	Jan	21	0	9	52	0	95	98	275	18.9%
	Feb	37	0	8	51	0	111	109	316	16.1%
	Mar	55	0	13	130	0	160	211	569	22.8%
	Apr	54	0	12	148	0	177	251	642	23.1%
	May	26	2	10	111	1	126	282	558	19.9%
	Avg	35	2	9	88	0	127	184	445	19.7%
2020/2021	Jun	27	5	7	48	1	75	153	316	15.2%
	Jul	9	16	4	22	0	73	43	167	13.2%
	Aug	22	2	4	26	0	71	74	199	13.1%
	Sep	65	0	19	114	0	195	215	608	18.8%
	Oct	67	4	17	161	2	208	313	772	20.9%
	Nov	52	1	42	151	0	160	265	671	22.5%
	Dec	31	1	7	97	0	75	243	454	21.4%
	Jan	39	1	6	46	0	79	117	288	16.0%
	Feb	36	0	11	52	0	115	113	327	15.9%
	Mar	73	0	11	92	0	175	220	571	16.1%
	Avg	42	3	13	81	0	123	176	437	17.3%

Table 12-68 shows that on average, 9.4 percent of outage requests not modeled in the Monthly Balance of Planning Period FTR Auction, labeled On Time according to the rules, were submitted after the monthly FTR auction bidding opening dates in the first 10 months of the 2020/2021 planning period, compared to 9.1 percent in the 2019/2020 planning period. On average, 66.1 percent of outage requests not modeled in the Monthly Balance of Planning Period FTR Auction, labeled Late according to the rules, were submitted after the Monthly Balance of Planning Period FTR Auction bidding opening dates in the first 10 months of the 2020/2021 planning period, compared to 66.1 percent in the 2019/2020 planning period.

Table 12-68 Transmission facility outage requests that are not modeled in Monthly Balance of Planning Period FTR Auction: June 2019 through March 2021

	2019/2020						2020/2021					
	On Time			Late			On Time			Late		
	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
Jun	673	86	11.3%	347	694	66.7%	799	104	11.5%	332	791	70.4%
Jul	391	64	14.1%	268	729	73.1%	430	90	17.3%	271	605	69.1%
Aug	357	44	11.0%	300	640	68.1%	438	74	14.5%	262	617	70.2%
Sep	894	124	12.2%	318	661	67.5%	1,062	86	7.5%	273	640	70.1%
Oct	1,110	120	9.8%	388	929	70.5%	1,192	70	5.5%	363	616	62.9%
Nov	1,000	63	5.9%	457	659	59.1%	964	71	6.9%	354	580	62.1%
Dec	737	63	7.9%	328	636	66.0%	739	67	8.3%	390	587	60.1%
Jan	580	37	6.0%	292	572	66.2%	606	73	10.8%	277	455	62.2%
Feb	645	51	7.3%	280	603	68.3%	593	47	7.3%	278	572	67.3%
Mar	1,318	98	6.9%	333	702	67.8%	1,365	62	4.3%	309	623	66.8%
Apr	1,502	178	10.6%	448	693	60.7%						
May	1,267	87	6.4%	484	702	59.2%						
Avg	873	85	9.1%	354	685	66.1%	819	74	9.4%	311	609	66.1%

Table 12-69 shows that on average, 70.9 percent of late outage requests which were not modeled in the Monthly Balance of Planning Period FTR Auction, submitted after the Monthly Balance of Planning Period FTR Auction bidding opening dates, were approved and complete in the first 10 months of the 2020/2021 planning period, compared to 71.8 percent in the 2019/2020 planning period.

Table 12-69 Late transmission facility outage requests: June 2019 through March 2021

	2019/2020			2020/2021		
	Completed Outages	Total	Percent Complete	Completed Outages	Total	Percent Complete
Jun	528	694	76.1%	574	791	72.6%
Jul	489	729	67.1%	436	605	72.1%
Aug	500	640	78.1%	447	617	72.4%
Sep	455	661	68.8%	436	640	68.1%
Oct	616	929	66.3%	419	616	68.0%
Nov	472	659	71.6%	392	580	67.6%
Dec	469	636	73.7%	440	587	75.0%
Jan	441	572	77.1%	341	455	74.9%
Feb	475	603	78.8%	390	572	68.2%
Mar	461	702	65.7%	440	623	70.6%
Apr	480	693	69.3%			
May	518	702	73.8%			
Avg	492	685	71.8%	432	609	70.9%

Transmission Facility Outage Analysis in the Day-Ahead Energy Market

Transmission facility outages also affect the energy market. Just as with the FTR market, it is critical that outages that affect the operating day are known prior to the submission of offers in the day-ahead energy market so that market participants can understand market conditions and PJM can accurately model market conditions in the day-ahead market. PJM requires transmission owners to submit changes to outages scheduled for the next two days no later than 09:30 am.[93]

There are three relevant time periods for the analysis of the impact of transmission outages on the energy market: before the day-ahead market is closed; when the day-ahead market save cases are created; and during the operating day. The list of approved or active outage requests before the day-ahead market is closed is available to market participants. The day-ahead market model uses outages included in the day-ahead market save cases as an input. The outages that actually occurred during the operating day are the outages that affect the real-time market. If the three sets of outages are the same, there is no potential impact on markets. If the three sets of outages differ, there is a potential negative impact on markets. For example, if the list of outages before the day-ahead market was closed was different from the list of outages that included in the day-ahead market save cases, the day-ahead market participant would have inconsistent outage information as what day-ahead market model used.

For example for the operating day of May 5, 2018, Figure 12-6 shows that: there were 443 approved or active outages seen by market participants before the day-ahead market was closed; there were 329 outage requests included in the day-ahead market model; there were 315 outage requests included in both sets of outage; there were 128 outage requests approved or active before the day-ahead market was closed but not included as inputs in day-ahead market model; and there were 14 outage requests included in day-ahead market model but not available to market participants prior to the day-ahead market.

93 PJM, "Manual 3: Transmission Operations," Rev. 58 (Jan. 19, 2020).

Figure 12-6 Illustration of day-ahead market analysis: May 5, 2018

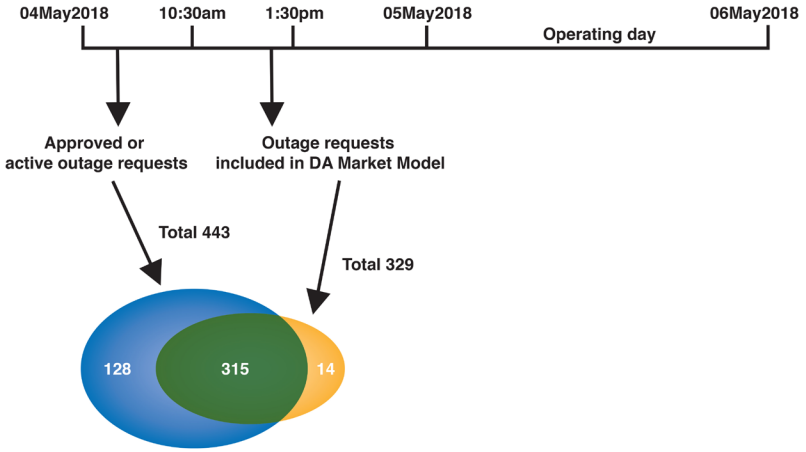


Figure 12-7 compares the weekly average number of active or approved outages available to market participants prior to the close of the day-ahead market with the outages included as inputs to the day-ahead market by PJM.

Figure 12-7 Approved or active outage requests: January 2015 through March 2021

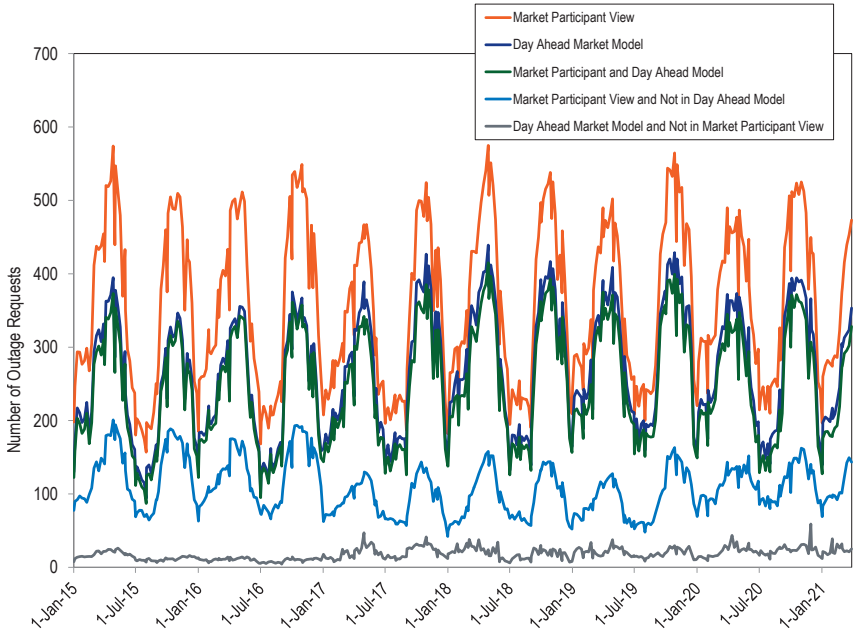


Figure 12-8 compares the weekly average number of outages included as inputs to the day-ahead market by PJM with the outages that actually occurred during the operating day.

Figure 12-8 Day-ahead market model outages: January 2015 through March 2021

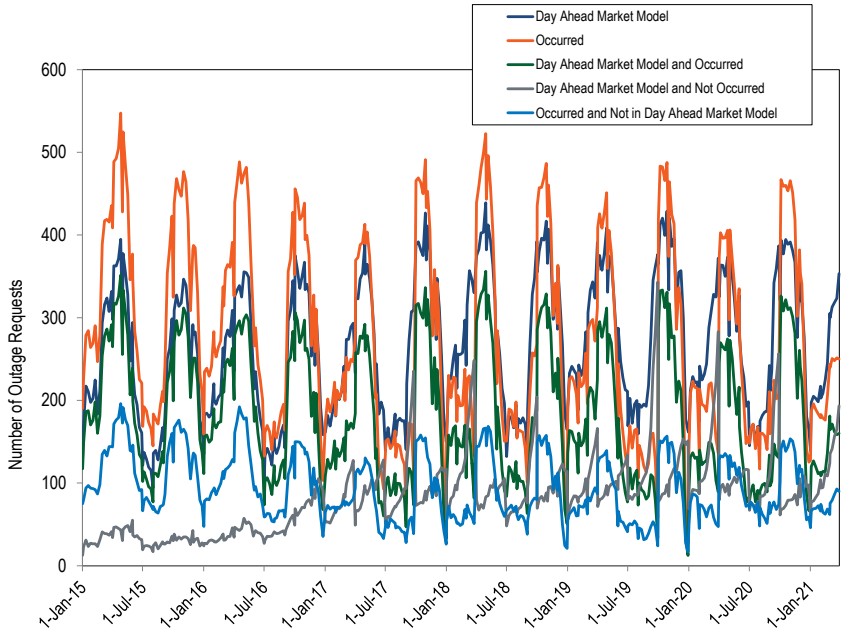


Figure 12-9 compares the weekly average number of active or approved outages available to market participants prior to the close of the day-ahead market with the outages that actually occurred during the operating day.

Figure 12-9 Approved or active outage requests: January 2015 through March 2021

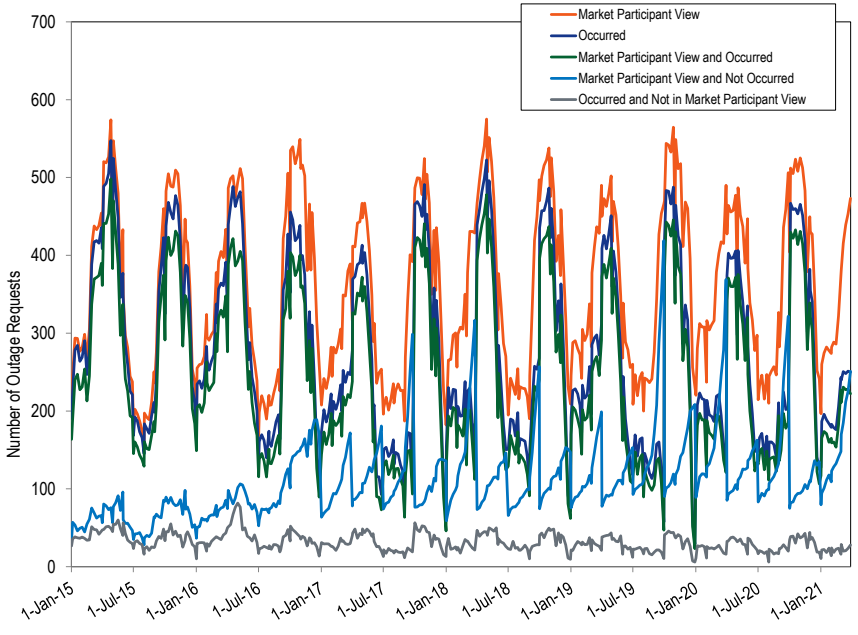


Figure 12-7, Figure 12-8, and Figure 12-9 show that on a weekly average basis, the active or approved outages available to day-ahead market participants, the outages included as inputs in the day-ahead market model and the outages that actually occurred in real time are not consistent. The active or approved outages available to day-ahead market participants are more consistent with the outages that actually occurred in real time than with the outages included in the day-ahead market model.

Summary: Comments Comments of the Independent Market Monitor for PJM in the Matter of the Ohio Power Siting Board's Report to the General Assembly Regarding the Power Transmission System electronically filed by Ms. Suzette N Krausen on behalf of Monitoring Analytics, LLC