Generation and Transmission Planning[1]

Overview

Generation Interconnection Planning

Existing Generation Mix

- As of December 31, 2021, PJM had a total installed capacity of 199,195.3 MW, of which 49,074.4 MW (24.6 percent) are coal fired steam units, 52,094.7 MW (26.2 percent) are combined cycle units and 33,452.6 MW (16.8 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 199,195.3 MW of installed capacity, 72,821.7 MW (36.6 percent) are from units older than 40 years, of which 37,643.4 MW (51.7 percent) are coal fired steam units, 191.0 MW (0.3 percent) are combined cycle units and 17,342.6 MW (23.8 percent) are nuclear units.

Generation Retirements[2]

- There are 48,406.2 MW of generation that have been, or are planned to be, retired between 2011 and 2024, of which 37,420.2 MW (77.3 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 2021, 1,307.8 MW of generation retired. The largest generators that retired in 2021 were the 667.0 MW Chalk Point Unit 1 and 2 coal fired steam units located in the PEPCO Zone. Of the 1,307.8 MW of generation that retired, 669.4 MW (51.2 percent) were located in the PEPCO Zone.
- As of December 31, 2021, there are 7,081.0 MW of generation that have requested retirement after December 31, 2021, of which 1,300.0 MW (18.4 percent) are located in the DUKE Zone. Of the generation requesting retirement in the DUKE Zone, all 1,300.0 MW (100.0 percent) are coal fired steam 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 2021, the AG2 and AH1 queue windows closed, and the AH2 queue window opened. As projects move through the queue process, projects can be removed from the queue due to incomplete or invalid data, withdrawn by the market participant or placed in service.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 December 31, 2021, there were 254,914.6 MW in generation queues, in the status of active, under construction or suspended, an increase of 81,732.2 MW (47.2 percent) from the end of 2020.[4]
- As of December 31, 2021, 7,143 projects, representing 761,657.5 MW, have entered the queue process since its inception in 1998. Of those, 1,007 projects, representing 76,511.8 MW, went into service. Of the projects that entered the queue process, 3,269 projects, representing 430,231.1 MW (56.5 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 December 31, 2021, 254,914.6 MW were in generation request queues in the status of active, under construction or suspended. Based on historical completion rates, 41,074.4 MW (16.1 percent) 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 4,491 projects entered from January 2015 through December 2021, 3,344 projects (74.5 percent) were renewable. Of the 1,301 projects entered in 2021, 956 projects (73.5 percent) were renewable. Renewable projects make up 76.0 percent of all projects in the queue and those projects account for 75.1 percent of the nameplate MW currently active, suspended or under construction in the queue as of December 31, 2021.

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 December 31, 2021) <http://www.pjm.com/planning/services-requests/gen-deactivations.aspx>.

3 See PJM. Planning. "New Services Queue," (Accessed on December 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.

But of the 191,352.4 MW of renewable projects in the queue, only 9,781.6 MW (5.1 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 cost/benefit analysis that should be addressed prior to approval of additional projects. PJM's cost/benefit analysis does not correctly account for the costs of increased congestion associated with market efficiency projects.
- Through December 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 770.0 percent, from 20 for years 1998 through 2007 (pre Order No. 890[7]) to 174 for years 2008 through 2021 (post Order 890).

End of Life Transmission Projects

- An end of life transmission project is a project submitted for the purpose of replacing existing infrastructure that 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 defined mechanism to permit competition to build the project. Under the current approach, end of life projects are excluded from competition.

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.[8] In 2021, the PJM Board approved $1.11 billion in upgrades. As of December 31, 2021, the PJM Board

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

has approved $38.9 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 December 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.[9]
- There were 10,753 transmission outage requests submitted in the first seven months of the 2021/2022 planning period. Of the requested outages, 74.8 percent of the requested outages were planned for less than or equal to five days and 9.9 percent of requested outages were planned for greater than 30 days. Of the requested outages, 43.6 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.[10] (Priority: Low. First reported 2013. Status: Partially adopted, 2012.)

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,

9 See "PJM Manual 03: Transmission Operations," Rev. 60 (November 17, 2021).
10 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>.

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 cost/benefit 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.)[11]
- 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.)[12]
- 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

11 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).

12 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).

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 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 and that all PJM transmission owners implement dynamic line ratings (DLR), subject to NERC standards and guidelines, subject to review by NERC, PJM and the MMU, 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.)
- 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 or even permit 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

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

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 the 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. 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. PJM is in the process of developing and finalizing significant modifications to the queue process which are expected to be filed with FERC in 2022. 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. 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.

The roles and efficiency of PJM, TOs and developers in the queue process all need to be examined and enhanced in order to help ensure that the queue process can function effectively and efficiently as the gateway to competition in the energy and capacity markets and not as a barrier to competition.

The Commission should require PJM, for example, to 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.

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 cost/benefit analysis which cause it to consistently overstate the potential benefits of market efficiency projects. The market efficiency process is misnamed. 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 cost/benefit analysis that should be addressed prior to approval of additional projects. The current cost/benefit 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 cost/benefit 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. The PJM process for evaluating the congestion impact of transmission outages needs to be clearly defined and upgraded to provide for management of transmission outages to minimize market impacts. The MMU continues to recommend that PJM draft a clear definition of the congestion analysis required for transmission outage requests that is incorporated in the PJM Market Rules.

Generation Interconnection Planning

Existing Generation Mix

Table 12-1 shows the existing PJM capacity by control zone and unit type.[14] As of December 31, 2021, PJM had an installed capacity of 199,195.3 MW, of which 49,074.4 MW (24.6 percent) are coal fired steam units, 52,094.7 MW (26.2 percent) are combined cycle units and 33,452.6 MW (16.8 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 199,195.3 MW of PJM installed capacity, 32,253.1 MW (16.2 percent) are in the AEP Zone, of which 13,463.0 MW (41.7 percent) are coal fired steam units, 7,475.0 MW (23.2 percent) are combined cycle units and 2,071.0 MW (6.4 percent) are nuclear units.

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

Table 12-1 Existing capacity: December 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	5.9	64.1	0.0	0.0	458.9	0.0	0.0	0.0	7.5	0.0	2,014.5
AEP	4.0	7,475.0	4,108.2	16.2	4.8	0.0	66.0	420.9	2,071.0	0.0	0.0	20.4	364.7	0.0	0.0	13,463.0	738.0	0.0	0.0	3,500.9	0.0	32,253.1
APS	80.4	2,843.7	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	985.1	0.0	10,725.0
ATSI	0.0	4,647.5	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	2,128.0	325.0	0.0	136.0	0.0	0.0	11,028.5
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	150.0	2,271.1	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	29,830.5
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	14.4	0.0	0.0	0.0	0.0	0.0	565.0	0.0	0.0	0.0	0.0	0.0	2,478.7
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	3,096.9	0.0	0.0	3,499.2	35.0	800.0	368.4	587.0	0.0	28,942.2
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	320.4	0.0	0.0	410.0	710.0	153.0	70.0	0.0	0.0	4,994.4
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	140.0	0.0	0.0	0.0	0.0	14.1	396.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3,577.0
MEC	0.0	2,595.0	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	3,222.9
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	8.7	2.5	0.0	0.0	1,229.0	1,164.1	0.0	52.0	0.0	0.0	5,265.0
PPL	20.0	5,558.5	304.6	286.2	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	14,725.6
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	220.3	0.0	0.0	0.0	3.0	0.0	179.1	0.0	0.0	9,299.5
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	348.5	52,094.7	24,708.3	4,035.1	43.8	32.0	4,792.0	3,040.6	33,452.6	176.1	218.5	349.0	4,842.2	0.0	0.0	49,074.4	8,312.6	1,350.0	1,096.5	11,228.4	0.0	199,195.3

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 199,195.3 MW of installed capacity, 48,811.3 MW (24.5 percent) are in Pennsylvania, of which 9,281.4 MW (19.0 percent) are coal fired steam units, 18,087.2 MW (37.1 percent) are combined cycle units and 8,843.8 MW (18.1 percent) are nuclear units.

Table 12-2 Existing capacity: December 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	710.0	0.0	70.0	0.0	0.0	2,412.4
IL	150.0	2,271.1	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	29,830.5
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	130.1	0.0	0.0	3,923.8	0.0	0.0	0.0	2,353.2	0.0	8,694.9
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	18.9	333.4	0.0	0.0	2,987.0	1,307.6	550.0	109.0	295.0	0.0	12,367.5
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	1,006.5	0.0	0.0	0.0	0.0	0.0	0.0	208.0	0.0	1,712.5
NJ	47.7	7,474.7	2,115.0	251.6	0.0	2.0	140.0	5.0	3,493.0	0.0	4.0	29.0	680.6	0.0	0.0	458.9	3.0	0.0	179.1	7.5	0.0	14,891.0
OH	22.0	8,609.7	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	9,553.0	47.0	0.0	136.0	1,147.7	0.0	27,207.2
PA	49.9	18,087.2	1,544.5	1,584.7	20.6	0.0	1,583.0	1,445.7	8,843.8	176.1	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	48,811.3
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	0.0	0.0	0.0	0.0
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	2,200.4	0.0	0.0	2,494.2	495.0	800.0	368.4	12.0	0.0	27,374.5
WV	58.9	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	791.7	0.0	14,636.8
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	348.5	52,094.7	24,708.3	4,035.1	43.8	32.0	4,792.0	3,040.6	33,452.6	176.1	218.5	349.0	4,842.2	0.0	0.0	49,074.4	8,312.6	1,350.0	1,096.5	11,228.4	0.0	199,195.3

Table 12-3 and Figure 12-1 show the age of existing PJM generators, by unit type, as of December 31, 2021. Of the 199,195.3 MW of installed capacity, 72,821.7 MW (36.6 percent) are from units older than 40 years, of which 37,643.4 MW (51.7 percent) are coal fired steam units, 191.0 MW (0.3 percent) are combined cycle units and 17,342.6 MW (23.8 percent) are nuclear units.

Table 12-3 Capacity (MW) by unit type and age (years): December 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	348.5	45,876.9	10,371.4	0.0	43.8	32.0	0.0	297.2	0.0	164.1	20.0	260.3	4,842.2	0.0	0.0	3,475.0	82.0	0.0	47.4	11,204.4	0.0	77,065.1
20 to 40	0.0	6,026.8	13,814.6	960.0	0.0	0.0	3,003.0	427.2	16,110.0	12.0	25.0	88.7	0.0	0.0	0.0	7,956.0	18.0	0.0	843.1	24.0	0.0	49,308.4
40 to 60	0.0	191.0	522.3	3,075.1	0.0	0.0	1,789.0	340.0	17,342.6	0.0	173.5	0.0	0.0	0.0	0.0	34,613.6	6,451.1	1,350.0	0.0	0.0	0.0	65,848.2
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	3,029.8	1,761.5	0.0	206.0	0.0	0.0	6,973.5
Total	348.5	52,094.7	24,708.3	4,035.1	43.8	32.0	4,792.0	3,040.6	33,452.6	176.1	218.5	349.0	4,842.2	0.0	0.0	49,074.4	8,312.6	1,350.0	1,096.5	11,228.4	0.0	199,195.3

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.

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

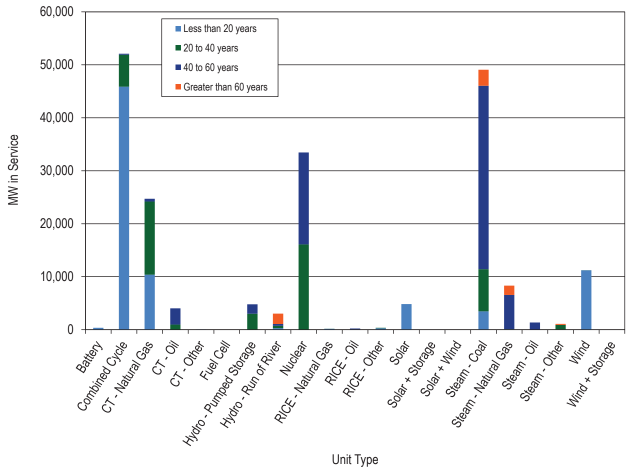


Figure 12-2 is a map of units, less than 20 MW in size that came online between January 1, 2011, and December 31, 2021. A mapping to these unit names is in Table 12-4.

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

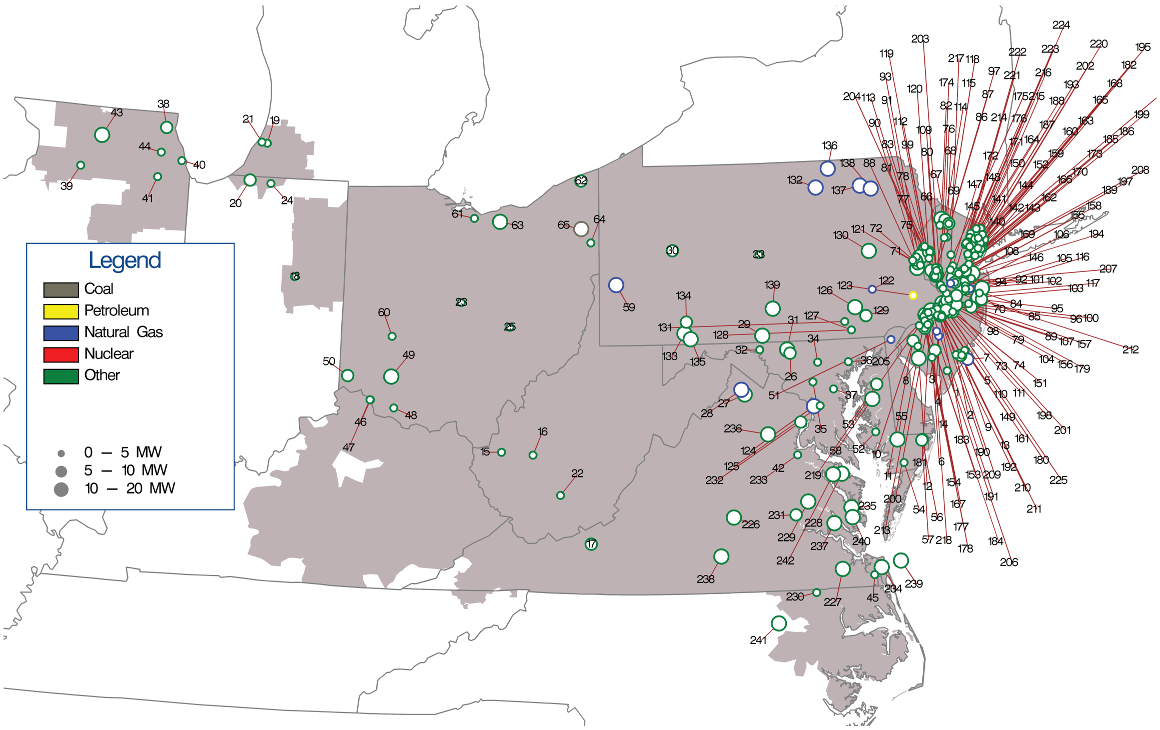


Table 12-4 Unit identification for map of unit additions (less than 20 MW): January 1, 2011 through December 31, 2021

ID	Unit	ID	Unit	ID	Unit	ID	Unit	ID	Unit
1	ACE CAPE MAY COUNTY 1 LF	56	DPL WORCESTER NORTH 1 SP	111	JC PEMBERTON 2 SP	166	PS FORTY NINTH SOLAR 1 SP	221	PS W CALDWELL SOLAR 1 SP
2	ACE CATES ROAD 2 SP	57	DPL WORCESTER SOUTH 2 SP	112	JC QUAKERTOWN 9 SP	167	PS GLOUCESTER SOLAR 1 SP	222	PS W CALDWELL SOLAR 2 SP
3	ACE CEDAR BRANCH 1 SP	58	DPL WYE MILLS 1 SP	113	JC RICHLINE 3 SP	168	PS HACKENSACK 1 SP	223	PS WALDWICK SOLAR 1 SP
4	ACE EGG HARBOR-KELLOGG 1 FC	59	DUQ PIT MICROGRID 1 CT	114	JC RINGOES 1 SP	169	PS HIGHLAND PARK 3 BT	224	PS WEST ORANGE SOLAR 1 SP
5	ACE GALLOWAY LANDFILL 2 SP	60	FE DOVETAIL 1 CT	115	JC SUSSEX 1 LF	170	PS HIGHLAND PARK 4 SP	225	PS WEST PEMBERTON 1 SP
6	ACE MAYS LANDING 1 SP	61	FE ERIE COUNTY 1 LF	116	JC TINTON FALLS 3 SP	171	PS HILLSDALE SOLAR 1 SP	226	VP BUCKINGHAM 1 SP
7	ACE MIDTOWN THERMAL 2 CT	62	FE GENEVA 1 LF	117	JC UPPER FREEHOLD 1 SP	172	PS HINCHMANS SOLAR 1 SP	227	VP GARDNER FARMS 1 SP
8	ACE OAK FAIRTON 1 SP	63	FE LORAIN 1 LF	118	JC WANTAGE 2 SP	173	PS HOBOKEN SOLAR 2 SP	228	VP GARDYS MILL ROAD 5 SP
9	ACE PEAR STREET 1 SP	64	FE MAHONING 1 LF	119	JC WARREN 1 SP	174	PS HOPEWELL 1 SP	229	VP HOLLYFIELD 1 SP
10	ACE PILESGROVE 1 SP	65	FE WARREN-EVERGREEN 1 CT	120	JC WASHBURN AVE 4 SP	175	PS HOPEWELL 2 BT	230	VP MURPHY 1 SP
11	ACE PILESGROVE 2 SP	66	JC AUGUSTA 1 SP	121	ME GLENDON 1 LF	176	PS JACKSON SOLAR 1 SP	231	VP NORTHEAST 2 LF
12	ACE PITTSGROVE 1 SP	67	JC BEAVER RUN 3 SP	122	ME READING HOSPITAL 1 CT	177	PS KINSLEY BEAVER 2 SP	232	VP OCCOQUAN 1 LF
13	ACE SEASHORE 1 SP	68	JC BERKSHIRE 2 SP	123	PE MORRIS ROAD 1 D	178	PS KINSLEY DEPTFORD 1 SP	233	VP OCCOQUAN 2 LF
14	ACE TANSBORO ROAD 1 FC	69	JC BERNARDS TOWNSHIP 1 SP	124	PEP CAPITAL POWER PLANT 1 CT	179	PS KUSER SOLAR 1 SP	234	VP OCEANA 1 SP
15	AEP BALLS GAP 1 BT	70	JC BRICKYARD 4 SP	125	PEP ROLLINS AVENUE 3 SP	180	PS LANDFILL 5 SP	235	VP PULLER 1 SP
16	AEP CHARLESTON 1 LF	71	JC COPPER HILL 4 SP	126	PL DART CONTAINER 1-2 LF	181	PS LAWNSIDE 14 BT	236	VP REMINGTON 1 SP
17	AEP CLOYDS MT 1 LF	72	JC CYPHERS ROAD 5 SP	127	PL HOLTWOOD 11	182	PS LEONIA SOLAR 1 SP	237	VP ROCHAMBEAU 1 SP
18	AEP DEERCREEK 1 SP	73	JC DIXSOLAR 51 SP	128	PL HOLTWOOD 13	183	PS LUMBERTON STACY HAINES 5 SP	238	VP TWITTYS CREEK 1 SP
19	AEP EAST WATERVLIET 1 SP	74	JC DIXSOLAR 52 SP	129	PL KEYSTONE 1 SP	184	PS MANTUA CREEK 7 BT	239	VP VIRGINIA OFFSHORE 1 WF
20	AEP OLIVE 1 SP	75	JC DOMIN LANE 1 SP	130	PL PA SOLAR 1 SP	185	PS MARION SOLAR 1 SP	240	VP WAN - GLOUCESTER 1 SP
21	AEP ORCHARD HILLS 1 LF	76	JC DURBAN AVENUE 1 SP	131	PL TURKEY HILL 1 WF	186	PS MATRIX PA SOLAR 2 SP	241	VP WHITAKERS 1 SP
22	AEP RALEIGH COUNTY 1 LF	77	JC E FLEMINGTON 5 SP	132	PN ALPACA GLORY BARN 1 D	187	PS MAYWOOD SOLAR 1 SP	242	VP WOODBINE ROAD 1 SP
23	AEP TRENT 1 BT	78	JC EAST AMWELL 7 SP	133	PN GARRETT 1 BT	188	PS METRO HQ 2 SP		
24	AEP TWINBRANCH 1 SP	79	JC EGYPT 3 SP	134	PN LAUREL HIGHLANDS 2 LF	189	PS MIDDLESEX 1 SP		
25	AEP ZANESVILLE 2 LF	80	JC FISCHER 8 SP	135	PN MEYERSDALE 2 BT	190	PS MILL CREEK 1 SP		
26	AP BAKER POINT 1 SP	81	JC FOUL RIFT ROAD 1 SP	136	PN MILAN ENERGY 1 D	191	PS MOORESTOWN 1 SP		
27	AP DOUBLE TOLLGATE SP	82	JC FRANKFORD 4 SP	137	PN NORTH MESHOPPEN 1 CT	192	PS MT LAUREL 1 SP		
28	AP HP HOOD 1 CT	83	JC FRANKLIN 7 SP	138	PN OXBOW CREEK ENERGY CENTER 1 D	193	PS NEW MILFORD SOLAR 1 SP		
29	AP LETZBURG - ELK HILL 2 SP	84	JC FREEMALL 1 FC	139	PN WHITETAIL 1 SP	194	PS NEW ROAD 1 SP		
30	AP MAHONING CREEK 1 H	85	JC FRENCHES 2 SP	140	PS ALDENE SOLAR 1 SP	195	PS NEWARK SOLAR 1 SP		
31	AP MT ST MARYS PV PARK 2 SP	86	JC FRENCHTOWN 1 SP	141	PS ATHENIA SOLAR 1 SP	196	PS NEWARK SOLAR 3 SP		
32	AP PINESBURG 1 SP	87	JC FRENCHTOWN 2 SP	142	PS BAYONNE 1 SP	197	PS NIXON LANE 2 SP		
33	AP STATE COLLEGE 1 BT	88	JC FRENCHTOWN 3 SP	143	PS BAYONNE SOLAR 2 SP	198	PS NORTH AMERICAN 4 SP		
34	BC ALPHA RIDGE 1 LF	89	JC HANOVER 2 SP	144	PS BELLEVILLE SOLAR 1 SP	199	PS NORTH AVE SOLAR 1 SP		
35	BC BRIGHTON DAM 1 H	90	JC HARMONY 1 SP	145	PS BENNETTS SOLAR 1 SP	200	PS OWENS CORNING 1 SP		
36	BC KINGSVILLE 1 SP	91	JC HIGH STREET 6 SP	146	PS BLACK ROCK 1 SP	201	PS PARKLANDS 1 SP		
37	BC MILLERSVILLE 1 LF	92	JC HOFFMAN STATION ROAD 2 SP	147	PS BRIDGEWATER SOLAR 2 SP	202	PS PATERSON PLANK ROAD 1 SP		
38	COM COUNTRYSIDE 1 LF	93	JC HOLLAND 4 SP	148	PS CALDWELL PUMP 2 BT	203	PS PENNINGTON 3 BT		
39	COM DIXON LEE 5 LF	94	JC HOLMDEL 9 SP	149	PS CAMPUS DRIVE 2 SP	204	PS PENNINGTON 4 SP		
40	COM GRAND RIDGE 6 BT	95	JC HOWELL 1 SP	150	PS CEDAR GROVE SOLAR 1 SP	205	PS PENNSAUKEN 1 LF		
41	COM MAGID GLOVE 1 BT	96	JC JACOBSTOWN 1 SP	151	PS CEDAR LANE FLORENCE 6 SP	206	PS PENNSAUKEN 3 SP		
42	COM MORRIS 1 LF	97	JC JUNCTION ROAD 6 SP	152	PS COOK ROAD SOLAR 2 SP	207	PS PRINCETON HOSPITAL 1 CT		
43	COM ORCHARD 1 LF	98	JC LAKEHURST 3 SP	153	PS COOPER HOSPITAL 1 BT	208	PS RARITAN CENTER 3 SP		
44	COM SOLBERG 1 BT	99	JC LEBANON 1 SP	154	PS COOPER HOSPITAL 15 SP	209	PS REEVES EAST 3 SP		
45	COM STERLING RAIL 1 BT	100	JC LEGLER LANDFILL 7 SP	155	PS CRANBURY 2 SP	210	PS REEVES SOUTH 1 SP		
46	DEOK BECKJORD 1 BT	101	JC MANALAPAN 1 SP	156	PS CROSSWIC 1 SP	211	PS REEVES WEST 4 SP		
47	DEOK BECKJORD 2 BT	102	JC MILLHURST 3 SP	157	PS CROSSWIC 2 SP	212	PS RIDER UNIVERSITY 3 SP		
48	DEOK BROWN COUNTY 1 LF	103	JC MUDDY FORGE 3 SP	158	PS DEVILSBROOK 1 SP	213	PS RIVER ROAD 2 SP		
49	DEOK CLINTON 1 BT	104	JC NORTH HANOVER 4 SP	159	PS DOREMUS SOLAR 1 SP	214	PS ROSELAND SOLAR 1 SP		
50	DEOK WILLEY 1 BT	105	JC NORTH PARK 1 SP	160	PS E RUTHERFORD SOLAR 1 SP	215	PS SADDLE BROOK SOLAR 1 SP		
51	DPL BLOOM ENERGY 1 FC	106	JC NORTH PARK 2 SP	161	PS EASTAMPTON 1 SP	216	PS SPRINGFIELD SOLAR 1 SP		
52	DPL BUCKTOWN 1 SP	107	JC NORTH RUN 11 SP	162	PS EDISON 1 SP	217	PS SUNNYMEADE SOLAR 1 SP		
53	DPL CHURCH HILL 1 SP	108	JC OLD BRIDGE 1 SP	163	PS ESSEX 105 CT	218	PS TAYLORS LANE 1 SP		
54	DPL COSTEN 1 SP	109	JC PAUCH 3 SP	164	PS FAIRLAWN SOLAR 1 SP	219	PS THOROFARE SOLAR 2 SP		
55	DPL HEBRON 1 SP	110	JC PEMBERTON 1 SP	165	PS FOODBANK 1 SP	220	PS TURNPIKE 1 SP		

Figure 12-3 is a map of units, 20 MW or greater in size, that came online between January 1, 2011 and December 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 December 31, 2021

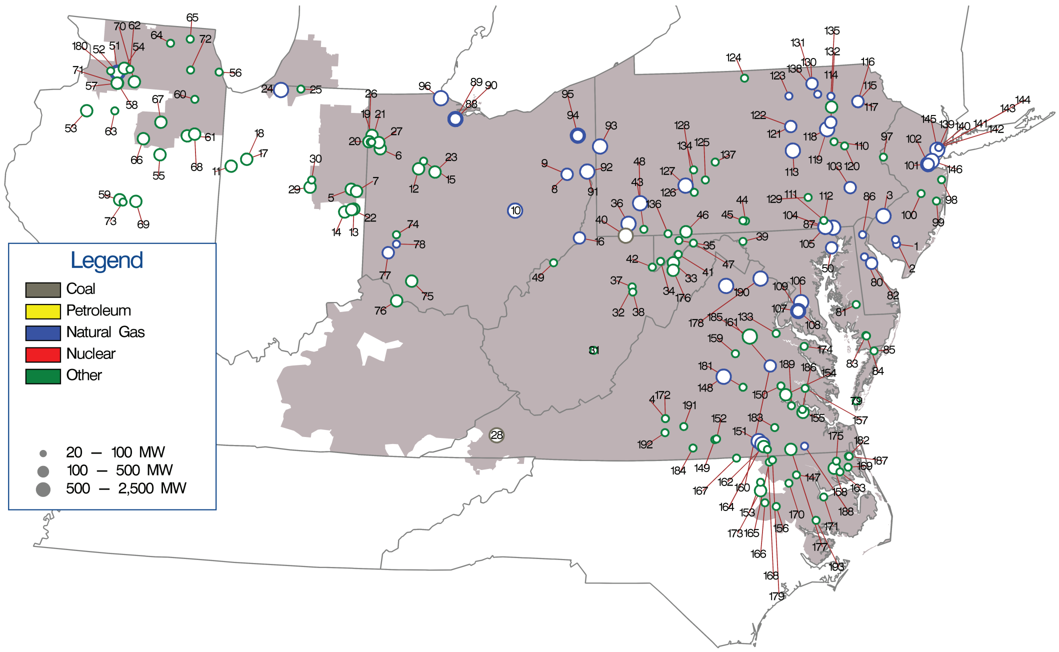


Table 12-5 Unit identification for map of unit additions (20 MW or greater): January 1, 2011 through December 31, 2021

ID	Unit	ID	Unit	ID	Unit	ID	Unit
1	ACE CLAYVILLE 1 CT	51	COM 942 NELSON 1 CC	101	JC WOODBRIDGE 1 CC	151	VP BRUNSWICK 1CC
2	ACE VINELAND 11 CT	52	COM 942 NELSON 2 CC	102	JC WOODBRIDGE 2 CC	152	VP BUTCHER CREEK 1 SP
3	ACE WEST DEPTFORD CROWN POINT 1 CC	53	COM BISHOP HILL SP in PJM WF	103	ME BIRDSBORO 1 CC	153	VP CHESTNUT 1 SP
4	AEP ALTAVISTA 1 SP	54	COM BLOOMING GROVE 1 WF1	104	PE DELTA 1-4 CC	154	VP CHICKAHOMINY 1 SP
5	AEP BITTER RIDGE 1 WF	55	COM BRIGHT STALK 1 WF	105	PE DELTA 5-7 CC	155	VP COLONIAL TRAIL WEST 1 SP
6	AEP BLUE CREEK 3 WF	56	COM GRAND RIDGE 7 BT	106	PEP KEYS ENERGY CENTER 1 CC	156	VP CONETOE 2 SP
7	AEP BLUFF POINT 2 WF	57	COM GREEN RIVER 1 WF	107	PEP ST CHARLES - KELSON RIDGE 1 CC	157	VP CORRECTIONAL 1 SP
8	AEP CARROLL COUNTY 1 CC	58	COM GREEN RIVER 2 WF	108	PEP ST CHARLES-KELSON RIDGE 1 CC	158	VP DESERT 1 WF
9	AEP CARROLL COUNTY 2 CC	59	COM HILLTOPPER 1 WF	109	PEP ST CHARLES-KELSON RIDGE 2 CC	159	VP DESPER 1 SP
10	AEP DRESDEN 1 CC	60	COM JOLIET 1 BT	110	PL HAZEL 1 FW	160	VP DOSWELL 2 CT
11	AEP FOWLER RIDGE 4 WF	61	COM KELLY CREEK 1 WF	111	PL HOLTWOOD 18	161	VP DOSWELL 3 CT
12	AEP HARDIN 2 SP	62	COM LEE DEKALB 3 BT	112	PL HOLTWOOD 19	162	VP DRY BREAD 1 SP
13	AEP HEADWATERS 1 WF	63	COM LONE TREE 3 WF	113	PL HUMMEL STATION 1 CC	163	VP ELIZABETH CITY 1 SP
14	AEP HEADWATERS 2 WF	64	COM MARENGO 1 BT	114	PL HUNLOCK CC	164	VP GREENSVILLE 1 CC
15	AEP HOG CREEK 1 WF	65	COM MCHENRY 1 BT	115	PL LACKAWANNA COUNTY 1 CC	165	VP GUTENBERG - OCONECHE 1 SP
16	AEP LONG RIDGE ENERGY 1 CC	66	COM MINONK 1 WF	116	PL LACKAWANNA COUNTY 2 CC	166	VP HARTS MILL 1 SP
17	AEP MEADOW LAKE 5 WF	67	COM OTTER CREEK 1 WF	117	PL LACKAWANNA COUNTY 3 CC	167	VP HAWTREE CREEK 1 SP
18	AEP MEADOW LAKE 6 WF	68	COM PILOT HILL 1 WF	118	PL MOXIE FREEDOM 11 CC	168	VP IVORY LANE 1 SP
19	AEP PAULDING 3 WF	69	COM RADFORDS RUN 1 WF	119	PL MOXIE FREEDOM 21 CC	169	VP IVY NECK 2 SP
20	AEP PAULDING 41 WF	70	COM SHADY OAKS 1 WF	120	PL PA SOLAR 2 SP	170	VP KELFORD 1 SP
21	AEP PAULDING 42 WF	71	COM WALNUT RIDGE 1 WF	121	PL PATRIOT 1 F	171	VP MACKEYS 1 SP
22	AEP RIVERSTART 1 SP	72	COM WEST CHICAGO 3 BT	122	PL PATRIOT 2 F	172	VP MECHANICSVILLE 2 SP
23	AEP SCIOTO RIDGE 1 WF	73	COM WHITNEY HILL 2 WF	123	PN BEAVER DAM 1 D	173	VP MOCCASIN CREEK 1 SP
24	AEP ST JOSEPH ENERGY CENTER 1 CC	74	DAY TAIT 8 BT	124	PN BIG LEVEL 1 WF	174	VP MONTROSS 1 SP
25	AEP ST JOSEPH SOLAR PARK 1 SP	75	DEOK HILLCREST 1 SP	125	PN CHESTNUT FLATS 1 WF	175	VP MORGAN CORNER 1 SP
26	AEP TIMBER2 1 WF	76	DEOK MELDAHL DAM 1 H	126	PN FAIRVIEW 1 CC	176	VP NEW CREEK 1 WF
27	AEP TRISHE 1 WF	77	DEOK MIDDLETOWN ENERGY 1 CC	127	PN FAIRVIEW 2 CC	177	VP NEWSOMS 1 SP
28	AEP VIRGINIA CITY 1 F	78	DEOK YANKEE 1 F	128	PN HIGHLAND NORTH 2 WF	178	VP PANDA STONEWALL 1 CC
29	AEP WILDCAT 1A WF	79	DPL CHERRYDALE 1 SP	129	PN LAUREL HILLS 1 WF	179	VP PECAN 1 SP
30	AEP WILDCAT 1B WF	80	DPL DEMEC - CLAYTON 2 CT	130	PN LIBERTY ASYLUM 10 F	180	VP POCATY 1 SP
31	AP BEECH RIDGE 2 WF	81	DPL DORCHESTER COUNTY 1 SP	131	PN LIBERTY ASYLUM 20 F	181	VP POWHATAN 2 SP
32	AP BEECH RIDGE 3 BT	82	DPL GARRISON EC 1 CC	132	PN MEHOOPANY 1 WF	182	VP RANCHLAND 2 SP
33	AP BLACK ROCK 1 WF	83	DPL GREAT BAY KINGS CREEK 1 SP	133	PN MEHOOPANY 2 WF	183	VP SAPONY 1 SP
34	AP FAIR WIND 2 WF	84	DPL GREAT BAY KINGS CREEK 2 SP	134	PN PATTON 1 WF	184	VP SOUTH BOSTON 1 F
35	AP FOURMILE RIDGE 1 WF	85	DPL OAK HALL 1 SP	135	PN PGCOGEN 2 CT	185	VP SPOTSYLVANIA 1 SP
36	AP GREENE COUNTY 1 CC	86	DPL RED LION 1 FC	136	PN RINGER HILL 1 WF	186	VP SPRING GROVE 1 SP
37	AP LAUREL MOUNTAIN 1 BT	87	DPL WILDCAT POINT 1 CC	137	PN SANDY RIDGE 1 WF	187	VP SUMMIT FARMS 1 SP
38	AP LAUREL MOUNTAIN 1 WF	88	FE FREMONT 1 SCCT	138	PN SUGAR RUN 2 CT	188	VP UNION CAMP 9-10 F
39	AP MARLOWE 1 SP	89	FE FREMONT 2 SCCT	139	PS KEARNY 131 CT	189	VP WARDS CREEK 1 SP
40	AP NORTH LONGVIEW 1 F	90	FE FREMONT ENERGY CENTER 3 CC	140	PS KEARNY 132 CT	190	VP WARREN COUNTY FRONT ROYAL CC
41	AP PINNACLE 1 WF	91	FE HIBBETS MILLS ROAD 1 CC	141	PS KEARNY 133 CT	191	VP WATER STRIDER 1 SP
42	AP ROTH ROCK 1 WF	92	FE HIBBETS MILLS ROAD 2 CC	142	PS KEARNY 134 CT	192	VP WHITEHORN 1 SP
43	AP SOUTH CHESTNUT 1 WF	93	FE HICKORY RUN 1 CC	143	PS KEARNY 141 CT	193	VP WILKINSON ENERGY CENTER 1 SP
44	AP ST THOMAS 1 SP	94	FE LORDSTOWN ENERGY CENTER 1 CC	144	PS KEARNY 142 CT		
45	AP ST THOMAS 2 SP	95	FE LORDSTOWN ENERGY CENTER 2 CC	145	PS NEWARK ENERGY CENTER 10 CC		
46	AP TWIN RIDGES 1 WF	96	FE OREGON ENERGY CENTER 1 CC	146	PS SEWAREN 7 CC		
47	AP WARRIOR RUN 2 BT	97	JC EDGE ROAD 5 BT	147	VP AULANDER HOLLOMAN 1 SP		
48	AP WESTMORELAND 1 CC	98	JC HAMILTON ROAD 5 SP	148	VP BEAR GARDEN		
49	AP WILLOW ISLAND 1 H	99	JC OAK RIDGE 3 SP	149	VP BLUESTONE FARM 1 SP		
50	BC PERRYMAN 6 CT	100	JC PLUMSTED ENERGY 6 BT	150	VP BRIEL FARM 1 SP		

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

16 See PJM. Planning. "Generator Deactivations," (Accessed on December 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 Part 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>.

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]

Generation Retirements 2011 through 2024

Table 12-6 shows that as of December 31, 2021, there are 48,406.2 MW of generation that have been, or are planned to be, retired between 2011 and 2024, of which 37,420.2 MW (77.3 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	4.0	118.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	13.4	0.0	0.0	0.0	1,020.4	102.0	0.0	50.0	0.0	0.0	1,307.8
Planned Retirements (January 2022 and later)	40.0	240.5	150.6	284.3	0.0	0.0	0.0	0.0	0.0	0.0	21.0	2.5	0.0	0.0	0.0	6,342.1	0.0	0.0	0.0	0.0	0.0	7,081.0
Total	85.0	783.5	2,434.9	2,109.2	22.0	0.0	0.5	0.0	1,419.5	0.0	65.1	80.4	0.0	0.0	0.0	37,420.2	2,065.5	1,658.0	252.0	10.4	0.0	48,406.2

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 48,406.2 MW of units that has been, or are planned to be, retired between 2011 and 2024, 37,420.2 MW (77.3 percent) are coal fired steam units. These coal fired steam units have an average age of 52.4 years and an average size of 206.7 MW. Over half of the retiring coal fired steam units, 54.6 percent, are located in Ohio or Pennsylvania.

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>.

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	6	14.2	6.1	85.0	0.2%
Combined Cycle	6	130.6	29.1	783.5	1.6%
Combustion Turbine	131	25.4	35.6	4,566.1	9.4%
Natural Gas	64	38.0	41.5	2,434.9	5.0%
Oil	61	34.6	46.0	2,109.2	4.4%
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	2	709.8	47.2	1,419.5	2.9%
RICE	35	4.3	25.5	145.5	0.3%
Natural Gas	0	0.0	0.0	0.0	0.0%
Oil	14	4.7	39.6	65.1	0.1%
Other	21	3.8	11.4	80.4	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	213	157.3	45.7	41,395.7	85.5%
Coal	181	206.7	52.4	37,420.2	77.3%
Natural Gas	18	114.8	60.8	2,065.5	4.3%
Oil	6	276.3	45.6	1,658.0	3.4%
Other	8	31.5	23.8	252.0	0.5%
Wind	1	10.4	15.6	10.4	0.0%
Wind + Storage	0	0	0	0	0.0%
Total	395	122.5	45.2	48,406.2	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	664.0	136.0	0.0	0.0	0.0	0.0	800.0
IL	40.0	0.0	296.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20.4	0.0	0.0	0.0	2,818.1	0.0	0.0	0.0	0.0	0.0	3,174.5
IN	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	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	3.2	0.0	0.0	0.0	3,068.0	171.0	0.0	0.0	0.0	0.0	3,695.3
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	465.5	1,590.0	1,040.2	6.4	0.0	0.5	0.0	614.5	0.0	8.0	22.5	0.0	0.0	0.0	1,543.0	932.5	148.0	10.0	0.0	0.0	6,381.1
OH	42.0	0.0	0.0	307.0	0.0	0.0	0.0	0.0	0.0	0.0	19.3	5.4	0.0	0.0	0.0	15,117.4	0.0	0.0	0.0	0.0	0.0	15,491.1
PA	1.0	51.0	121.4	307.3	14.0	0.0	0.0	0.0	805.0	0.0	13.9	20.5	0.0	0.0	0.0	5,299.3	283.0	176.0	109.0	10.4	0.0	7,211.8
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	23.9	8.4	0.0	0.0	0.0	3,917.9	543.0	786.0	83.0	0.0	0.0	5,788.9
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	85.0	783.5	2,434.9	2,109.2	22.0	0.0	0.5	0.0	1,419.5	0.0	65.1	80.4	0.0	0.0	0.0	37,420.2	2,065.5	1,658.0	252.0	10.4	0.0	48,406.2

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

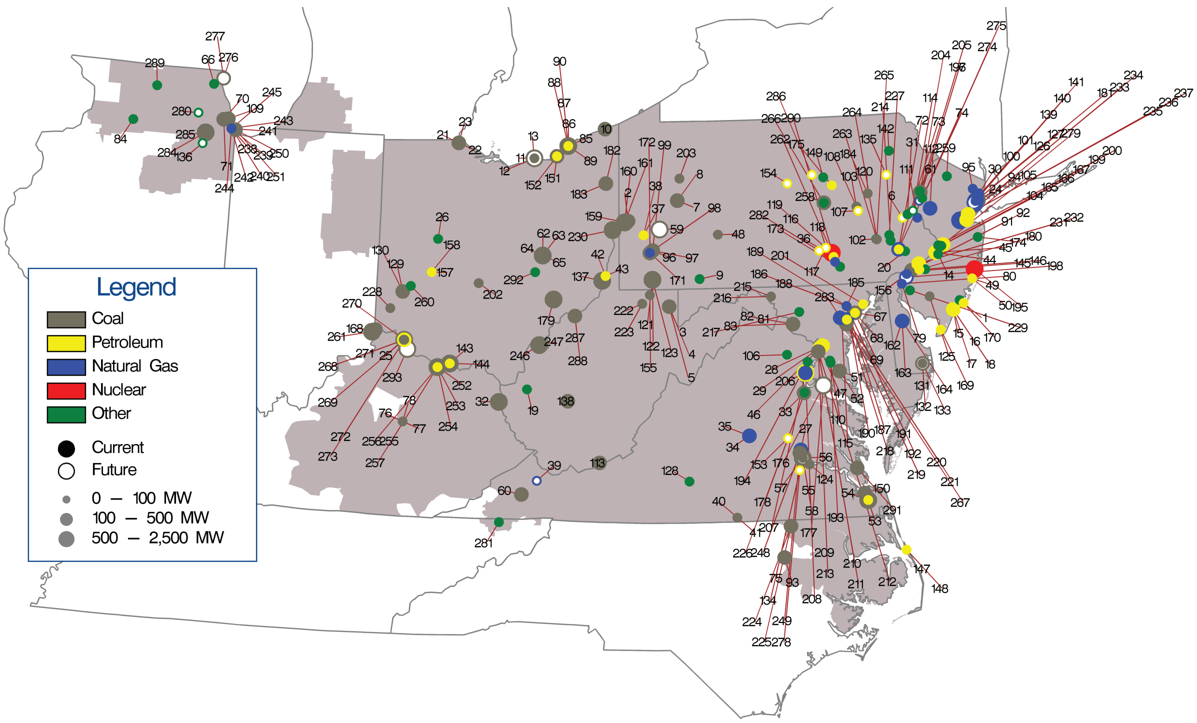


Table 12-9 Unit identification for map of unit retirements: 2011 through 2024

ID	Unit	ID	Unit	ID	Unit	ID	Unit	ID	Unit
1	AC Landfill Units 1 and 2	61	Columbia Dam Hydro	121	Hatfield's Ferry 1	181	New Bay Cogen CC	241	Southeast Chicago CT6
2	AES Beaver Valley	62	Conesville 3	122	Hatfield's Ferry 2	182	Niles 1	242	Southeast Chicago CT7
3	Albright 1	63	Conesville 4	123	Hatfield's Ferry 3	183	Niles 2	243	Southeast Chicago CT8
4	Albright 2	64	Conesville 5	124	Hopewell James River Cogeneration	184	Northeastern Power NEPCO	244	Southeast Chicago GT10
5	Albright 3	65	Conesville 6	125	Howard Down 10	185	Notch Cliff GT1	245	Southeast Chicago GT9
6	Allentown CT 1-4	66	Countryside Landfill	126	Hudson 1	186	Notch Cliff GT2	246	Sporn 1-4
7	Armstrong 1	67	Crane 1	127	Hudson 2	187	Notch Cliff GT3	247	Sporn 5
8	Armstrong 2	68	Crane 2	128	Hurt NUG	188	Notch Cliff GT4	248	Spruance NUG1 (Rich 1-2)
9	Arnold (Green Mtn. Wind Farm	69	Crane GT1	129	Hutchings 1-3, 5-6	189	Notch Cliff GT5	249	Spruance NUG2 (Rich 3-4)
10	Ashtabula 5	70	Crawford 7	130	Hutchings 4	190	Notch Cliff GT6	250	State Line 3
11	Avon Lake 10	71	Crawford 8	131	Indian River 1	191	Notch Cliff GT7	251	State Line 4
12	Avon Lake 7	72	Cromby 1	132	Indian River 3	192	Notch Cliff GT8	252	Stuart 1
13	Avon Lake 9	73	Cromby 2	133	Indian River 4	193	Oaks Landfill	253	Stuart 2
14	BC Landfill	74	Cromby D	134	Ingenco Petersburg	194	Occoquan 1 LF	254	Stuart 3
15	BL England 1	75	DINWIDDIE 1 CT	135	Jenkins CT 1-2	195	Oyster Creek	255	Stuart 4
16	BL England 2	76	Dale 1-2	136	Joliet Energy Storage	196	PL MARTINS CREEK 1-4 CT	256	Stuart Diesels 1-4
17	BL England 3	77	Dale 3	137	Kammer 1-3	197	PL MARTINS CREEK 1-4 CT	257	Stuart Diesels 1-4
18	BL England Diesel Units 1-4	78	Dale 4	138	Kanawha River 1-2	198	Pedricktown Cogen CC	258	Sunbury 1-4
19	Balls Gap Battery Facility	79	Deepwater 1	139	Kearny 10	199	Pennsbury Generator Landfill 1	259	Sussex County LF
20	Barbados AES Battery	80	Deepwater 6	140	Kearny 11	200	Pennsbury Generator Landfill 2	260	Tait Battery
21	Bay Shore 2	81	Dickerson Unit 1	141	Kearny 9	201	Perryman 2	261	Tanners Creek 1-4
22	Bay Shore 3	82	Dickerson Unit 2	142	Keystone Recovery (Units 1 - 7)	202	Picway 5	262	Three Mile Island Unit 1
23	Bay Shore 4	83	Dickerson Unit 3	143	Killen 2	203	Piney Creek NUG	263	Titus 1
24	Bayonne Cogen Plant (CC)	84	Dixon Lee Landfill Generator	144	Killen CT	204	Portland 1	264	Titus 2
25	Beckjord Battery Unit 2	85	Eastlake 1	145	Kimberly Clark Generator	205	Portland 2	265	Titus 3
26	Bellefontaine Landfill Generating Station	86	Eastlake 2	146	Kinsley Landfill	206	Possum Point 3	266	Viking Energy NUG
27	Bellemeade	87	Eastlake 3	147	Kitty Hawk GT 1	207	Possum Point 4	267	Wagner 2
28	Benning 15	88	Eastlake 4	148	Kitty Hawk GT 2	208	Possum Point 5	268	Walter C Beckjord 1
29	Benning 16	89	Eastlake 5	149	Koppers Co. IPP	209	Potomac River 1	269	Walter C Beckjord 2
30	Bergen 3	90	Eastlake 6	150	Lake Kingman	210	Potomac River 2	270	Walter C Beckjord 3
31	Bethlehem Renewable Energy Generator (Landfill)	91	Eddystone 1	151	Lake Shore 18	211	Potomac River 3	271	Walter C Beckjord 4
32	Big Sandy 2	92	Eddystone 2	152	Lake Shore EMD	212	Potomac River 4	272	Walter C Beckjord 5-6
33	Birchwood Plant	93	Edgecomb NUG (Rocky 1-2)	153	Lanier 1 CT	213	Potomac River 5	273	Walter C Beckjord GT 1-4
34	Bremo 3	94	Edison 1-3	154	Lock Haven CT 1	214	Pottstown LF (Moser)	274	Warren County Landfill
35	Bremo 4	95	Elmwood Park Power	155	MEA NUG (WVU)	215	R Paul Smith 3	275	Warren County NUG
36	Brunner Island Diesels	96	Elrama 1	156	MH50 Markus Hook Co-gen	216	R Paul Smith 4	276	Waukegan 7
37	Brunot Island 1B	97	Elrama 2	157	Mad River CTs A	217	Reichs Ford Road Landfill Generator	277	Waukegan 8
38	Brunot Island 1C	98	Elrama 3	158	Mad River CTs B	218	Riverside 4	278	Weakley CT
39	Buchanan 1-2	99	Elrama 4	159	Mansfield 1	219	Riverside 6	279	Werner 1-4
40	Buggs Island 1 (Mecklenberg)	100	Essex 10-11	160	Mansfield 2	220	Riverside 7	280	West Chicago Energy Storage
41	Buggs Island 2 (Mecklenberg)	101	Essex 12	161	Mansfield 3	221	Riverside 8	281	West Kingsport LF
42	Burger 3	102	Evergreen Power United Corstack	162	McKee 1	222	Riversville 5	282	West Shore CT 1-2
43	Burger EMD	103	FRACKVILLE WHEELABRATOR 1	163	McKee 2	223	Riversville 6	283	Westport 5
44	Burlington 8,11	104	Fairless Hills Landfill A	164	McKee 3	224	Roanoke Valley 1	284	Will County 3
45	Burlington 9	105	Fairless Hills Landfill B	165	Mercer 1	225	Roanoke Valley 2	285	Will County 4
46	Buzzard Point East Banks 1,2,4-8	106	Fauquier County Landfill	166	Mercer 2	226	Rockville CT	286	Williamsport-Lycoming CT 1-2
47	Buzzard Point West Banks 1-9	107	Fishbach CT 1	167	Mercer 3	227	Rolling Hills Landfill Generator	287	Willow Island 1
48	Cambria CoGen	108	Fishbach CT 2	168	Miami Fort 6	228	SMART Paper	288	Willow Island 2
49	Cedar 1	109	Fisk Street 19	169	Middle 1-3	229	Salem County LF	289	Winnebago Landfill
50	Cedar 2	110	GUDE Landfill	170	Missouri Ave B,C,D	230	Sammis 1-4	290	York Generation Facility
51	Chalk Point Unit 1	111	Gilbert 1-4	171	Mitchell 2	231	Schuylkill 1	291	Yorktown 1-2
52	Chalk Point Unit 2	112	Glen Gardner 1-8	172	Mitchell 3	232	Schuylkill Diesel	292	Zanesville Landfill
53	Chesapeake 1-4	113	Glen Lyn 5-6	173	Modern Power Landfill NUG	233	Sewaren 1	293	Zimmer 1
54	Chesapeake 7-10	114	Glendon LF	174	Monmouth NUG landfill	234	Sewaren 2		
55	Chesterfield 3	115	Gould Street Generation Station	175	Montour ATG	235	Sewaren 3		
56	Chesterfield 4	116	Harrisburg 4 CT	176	Morgantown Unit 1	236	Sewaren 4		
57	Chesterfield 5	117	Harrisburg CT 1	177	Morgantown Unit 2	237	Sewaren 6		
58	Chesterfield 6	118	Harrisburg CT 2	178	Morris Landfill Generator	238	Southeast Chicago CT11		
59	Cheswick 1	119	Harrisburg CT 3	179	Muskingum River 1-5	239	Southeast Chicago CT12		
60	Clinch River 3	120	Harwood 1-2	180	National Park 1	240	Southeast Chicago CT5		

Current Year Generation Retirements

Table 12-10 shows that in 2021, 1,307.8 MW of generation retired. The largest generators that retired in 2021 were the 667.0 MW Chalk Point Unit 1 and 2 coal fired steam units located in the PEPCO Zone. Of the 1,307.8 MW of generation that retired, 669.4 MW (51.2 percent) were located in the PEPCO Zone.

Table 12-10 Unit deactivations: 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
American Electric Power Company, Inc.	Balls Gap Battery Facility	2.0	Battery	AEP	4.2	22-Apr-21
Domtar Corporation	West Kingsport LF	50.0	Steam-Other	AEP	14.7	31-May-21
City of Dover	McKee 3	102.0	Steam-Natural Gas	DPL	46.1	01-Jun-21
GenOn Energy, Inc.	Chalk Point Unit 1	331.0	Steam-Coal	PEPCO	56.9	01-Jun-21
GenOn Energy, Inc.	Chalk Point Unit 2	336.0	Steam-Coal	PEPCO	56.3	01-Jun-21
Northeast Maryland Waste Disposal Authority	Oaks Landfill	2.4	RICE-Other	PEPCO	12.5	01-Jul-21
Riverstone Holdings LLC	York Generation Facility	51.0	Combined Cycle	MEC	32.7	20-Sep-21
South Jersey Industries, Inc.	AC Landfill Units 1 and 2	3.0	RICE-Other	ACEC	15.2	01-Oct-21
Total		1,307.8				

Planned Generation Retirements

Table 12-11 shows that, as of December 31, 2021, there are 7,081.0 MW of generation that have requested retirement after December 31, 2021. Of the 7,081.0 MW requesting retirement, 6,342.1 MW (89.6 percent) are coal fired steam units. As of December 31, 2021, there are planned coal fired unit retirements in seven different PJM zones. Of the 7,081.1 MW of planned retirements, 1,300.0 MW (18.4 percent) are located in the DUKE Zone. Of the generation requesting retirement in the DUKE Zone, 1,300.0 MW (100.0 percent) are coal fired steam units.

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

Company	Unit Name	ICAP (MW)	Unit Type	Zone Name	Projected Deactivation Date
Renewable Energy Systems Holdings LTD	Joliet Energy Storage	20.0	Battery	COMED	08-Feb-22
Renewable Energy Systems Holdings LTD	West Chicago Energy Storage	20.0	Battery	COMED	08-Feb-22
GenOn Energy, Inc.	Avon Lake 10	21.0	CT-Oil	ATSI	01-Apr-22
GenOn Energy, Inc.	Avon Lake 9	638.0	Steam-Coal	ATSI	01-Apr-22
GenOn Energy, Inc.	Cheswick 1	565.0	Steam-Coal	DUQ	01-Apr-22
Riverstone Holdings LLC	Fishbach CT 1	28.0	CT-Oil	PPL	01-Apr-22
Riverstone Holdings LLC	Fishbach CT 2	14.0	CT-Oil	PPL	01-Apr-22
Riverstone Holdings LLC	Jenkins CT 1-2	27.6	CT-Oil	PPL	01-Apr-22
Riverstone Holdings LLC	Lock Haven CT 1	14.0	CT-Oil	PPL	01-Apr-22
Riverstone Holdings LLC	West Shore CT 1	28.0	CT-Oil	PPL	01-Apr-22
Riverstone Holdings LLC	Williamsport-Lycoming CT 1-2	26.6	CT-Oil	PPL	01-Apr-22
Riverstone Holdings LLC	Harwood 1-2	28.0	CT-Oil	PPL	31-May-22
NRG Energy Inc	Indian River 4	410.0	Steam-Coal	DPL	31-May-22
Riverstone Holdings LLC	Martins Creek CT 4	17.3	CT-Natural_Gas	PPL	31-May-22
GenOn Energy, Inc.	Morgantown Unit 1	610.0	Steam-Coal	PEPCO	31-May-22
GenOn Energy, Inc.	Morgantown Unit 2	619.0	Steam-Coal	PEPCO	31-May-22
Riverstone Holdings LLC	New Bay Cogen CC	120.2	Combined Cycle	PSEG	31-May-22
Riverstone Holdings LLC	Pedricktown Cogen CC	120.3	Combined Cycle	ACEC	31-May-22
NRG Energy Inc	Waukegan 7	328.0	Steam-Coal	COMED	31-May-22
NRG Energy Inc	Waukegan 8	356.1	Steam-Coal	COMED	31-May-22
NRG Energy Inc	Will County 4	510.0	Steam-Coal	COMED	31-May-22
American Electric Power Company, Inc.	Zimmer 1	330.0	Steam-Coal	DUKE	31-May-22
The AES Corporation	Zimmer 1	365.0	Steam-Coal	DUKE	31-May-22
Vistra Energy Corp	Zimmer 1	605.0	Steam-Coal	DUKE	31-May-22
Riverstone Holdings LLC	Allentown CT 1-4	56.0	CT-Oil	PPL	01-Jun-22
Energy Power Investment Company, LLC	Glendon LF	2.5	RICE-Other	MEC	01-Jun-22
Riverstone Holdings LLC	Harrisburg CT 1	13.4	CT-Oil	PPL	01-Jun-22
Riverstone Holdings LLC	Harrisburg CT 2	13.9	CT-Oil	PPL	01-Jun-22
Riverstone Holdings LLC	Harrisburg CT 3	13.8	CT-Oil	PPL	01-Jun-22
Riverstone Holdings LLC	Martins Creek CT 1	18.0	CT-Natural_Gas	PPL	01-Jun-22
Riverstone Holdings LLC	Martins Creek CT 2	17.3	CT-Natural_Gas	PPL	01-Jun-22
Riverstone Holdings LLC	Martins Creek CT 3	18.0	CT-Natural_Gas	PPL	01-Jun-22
Dominion Energy, Inc.	Chesterfield 5	336.0	Steam-Coal	DOM	31-May-23
Dominion Energy, 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
Castleton Commodities International LLC	DINWIDDIE 1 CT	3.0	RICE-Oil	DOM	01-Jun-23
Castleton Commodities International LLC	Lanier 1 CT	7.0	RICE-Oil	DOM	01-Jun-23
Castleton Commodities International LLC	Rockville CT	4.0	RICE-Oil	DOM	01-Jun-23
Castleton Commodities International LLC	Weakley CT	7.0	RICE-Oil	DOM	01-Jun-23
Total		7,081.0			

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. But the behavior of project developers also creates issues with queue management and exacerbates the barriers.

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, Queue AH1 opened on April 1, 2021 and closed on September 10, 2021and Queue AH2 opened on October 1, 2021. On June 24, 2021, PJM requested tariff modifications to close queue windows on September 10 and March 10, rather than September 30 and March 31.[25] This change allows more time to review the new requests to the queue without shortening the amount of time available for the resulting model builds and analyses. On August 23, 2021, the Commission approved the tariff modifications.[26]

Projects submitted to the queue undergo a deficiency review to ensure that all required information is provided. If a project is missing information, or if the submitting developer owes money from a prior queue request, the submission is defined to be deficient. PJM was required to perform the review and provide notification within five business days of receipt of the request. The developer had ten business days to respond. PJM had five business days to review the response. As a result of the large number of project submissions submitted close to the end of each queue window, PJM could not meet the required timeline. On June 24, 2021, PJM filed tariff changes to modify the deficiency review timeline.[27] PJM requested an increase in the initial notification to the interconnection customer from five to 15 business days, or as soon thereafter as practicable, making the deadline flexible. The developer has ten business days to respond. PJM requested an increase in PJM's time to respond from five to 15 business days, or as soon thereafter as practicable, making the deadline flexible. On August 23, 2021, the Commission approved the tariff modifications.[28] A queue position is assigned once the project has met the submission requirements. 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.[29] 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.[30]

PJM has generally met the deadlines for feasibility and system impact studies. The increase in the number of projects submitted have contributed to a significant backlog in performing timely facility studies. The facility study includes the conceptual design, stability analyses

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 Filing, Docket ER21-2203 (June 24, 2021).
26 176 FERC ¶ 61,117 (2021).
27 See PJM Filing, Docket ER21-2203 (June 24, 2021).
28 176 FERC ¶ 61,117 (2021).
29 See "PJM Manual 14C: Generation and Transmission Interconnection Process," Rev. 14 (January 27, 2021).
30 PJM does not track the duration of suspensions or PJM termination of projects.

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. The PJM queue evaluation process should continue to be improved to help ensure that barriers to competition from new generation investments are not created.

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, resulting in the creation of the Interconnection Process Reform Task Force (IPRTF) to improve overall queue management. Proposals in the IPRTF include process efficiency enhancements, recognition of project clusters affecting the same transmission facilities, incentives to reduce the entry of speculative projects in the queue, and incentives to remove projects that are not expected to reach commercial operation.

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. Some project developers enter speculative projects in the queue and then put the project in suspended status.

On July 15, 2021, the Commission issued an Advance Notice of Proposed Rulemaking (ANOPR).[31] The purpose of the ANOPR is to review transmission related regulations and determine whether additional reforms to the regional transmission planning, cost allocation and generator interconnection processes are needed. The ANOPR discusses the impacts of transmission rules on the competitiveness of the energy markets but does not focus on the competitiveness of transmission itself. Given that the cost of transmission is increasing as a share of total wholesale power costs and now exceeds the cost of capacity in PJM, the cost effectiveness and competitiveness of the transmission planning and procurement process should be addressed when considering reforms.

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.

Interconnection Process Studies and Agreements[32]

In the study stage 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 the studies PJM perform in the study stage of the interconnection 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.

Table 12-12 Interconnection planning process: Study Stage

Study	Purpose
Feasibility Study	The feasibility study determines preliminary estimates of the type, scope, cost and lead time for construction of facilities required to interconnect the project.
System Impact Study	The system impact study is a comprehensive regional analysis of the impact of adding the new generation and/or transmission facility to the system. The study identifies the system constraints related to the project and the necessary attachment facilities, local upgrades, and network upgrades. The study refines and more comprehensively estimates cost responsibility and construction lead times for facilities and upgrades.
Facilities Study	In the facilities study, stability analysis is performed and the system impact study results are modified as necessary to reflect changes in the characteristics of other projects 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

31 See *Building for the Future through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection, Advanced Notice of Proposed Rulemaking*, 176 FERC ¶ 61,024 (July 15, 2021).
32 See "PJM Manual 14A: New Services Request Process," Rev. 29 (August 24, 2021) for a complete explanation of the interconnection process studies and agreements.

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.

In addition to the feasibility, system impact and facilities studies, PJM may also perform additional studies under certain circumstances. These studies include the affected systems study, interim deliverability study and the long term firm transmission studies. Table 12-13 is an overview of the additional studies PJM may perform.

Table 12-13 Interconnection planning process: Study Stage – Additional Studies

Study	Purpose
Affected System Study	PJM and its neighboring balancing authorities conduct interconnection studies to determine the impacts of interconnection requests on the neighboring transmission system.
Interim Deliverability Studies	Interim deliverability studies are conducted on a periodic basis in support of RPM auctions and other interconnection studies to determine if a new facility may come on line prior to its scheduled date. These studies evaluate the available system capability and provide the customer(s) with the availability of service by planning year. Interim deliverability studies use the same criteria used for the evaluation of the need for reinforcements associated with a project under study.
Long Term Firm Transmission Studies	Transmission service requests that extend beyond the available transfer capability horizon of 18 months are evaluated along with the other requests for service in the PJM new services queue to ensure deliverability. Long term firm transmission studies follow the same feasibility, system impact and facilities study process as new generation.

After the completion of a facility study, the project will enter the construction stage of the interconnection process. The final agreements required depend on the type of project. These agreements include a Construction Service Agreement (CSA), Interconnection Service Agreement (ISA), Upgrade Construction Service Agreement (UCSA), Wholesale Market Participant Agreement (WMPA) or Transmission Service Agreement (TSA). Table 12-14 is an overview of the agreements in the construction stage of the interconnection process.

Table 12-14 Interconnection planning process: construction stage agreements

Agreement	Purpose
Interconnection Service Agreement (ISA)	An ISA defines the generation or transmission developer's cost responsibility for required system upgrades. For generation interconnection customers, the ISA defines the capacity interconnection rights for a capacity resource and any operational restrictions or other limitations. For transmission interconnection customers, the ISA defines transmission injection and withdrawal rights and applicable incremental delivery, available transfer capability revenue and auction revenue rights.
Interim Interconnection Service Agreements (I-ISA)	If a developer wishes to start project construction activities prior to completion of the generation or transmission interconnection facilities study, the interim ISA would commit the developer to pay all costs incurred for the construction activities being advanced.
Interconnection Construction Service Agreement (CSA)	The CSA defines the standard terms and conditions of the interconnection, including construction responsibility, includes a construction schedule and contains notification and insurance obligations.
Upgrade Construction Service Agreement (USCA)	A new service customer who proposes to make an upgrade to an existing transmission facility or who seeks incremental auction revenue rights (IARRs) will receive an upgrade construction service agreement after their study process is completed.
Wholesale Market Participation Agreement (WMPA)	Developers interconnecting to non-FERC jurisdictional facilities who intend to participate in the PJM wholesale market will receive a three party agreement (WMPA). The WMPA is a non-Tariff agreement which must be filed with the FERC. The WMPA is essentially an ISA without interconnection provisions.

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 December 31, 2021, 254,914.6 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.[33]

33 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. In 2021, the AG2 and AH1 queue windows closed and the AH2 window opened. 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 December 31, 2021, there were 254,914.6 MW in generation queues, in the status of active, under construction or suspended, an increase of 81,732.2 MW (47.2 percent) from December 31, 2020. Table 12-15 shows MW in queues by expected completion year and MW changes in the queue between December 31, 2020, and December 31, 2021, for ongoing projects, i.e. projects with the status active, under construction or suspended.[34]

Table 12-15 Queue comparison by expected completion year (MW): December 31, 2020 and December 31, 2021[35]

			Year Change	
Year	As of 12/31/2020	As of 12/31/2021	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	0.0	(16.1)	(100.0%)
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	3.4	(16.0)	(82.5%)
2017	648.1	404.3	(243.8)	(37.6%)
2018	1,825.6	668.6	(1,157.0)	(63.4%)
2019	7,153.5	5,093.3	(2,060.2)	(28.8%)
2020	10,601.5	7,297.0	(3,304.4)	(31.2%)
2021	27,958.0	25,991.2	(1,966.8)	(7.0%)
2022	39,526.5	42,802.2	3,275.7	8.3%
2023	38,138.0	57,051.8	18,913.8	49.6%
2024	19,227.5	60,472.9	41,245.4	214.5%
2025	3,990.6	35,665.6	31,675.0	793.7%
2026	2,645.2	8,636.2	5,991.0	226.5%
2027	2,100.1	5,840.1	3,740.0	178.1%
2028	0.0	2,508.0	2,508.0	0.0%
2029	800.1	2,460.1	1,660.0	207.5%
Total	154,670.1	254,914.6	100,244.5	64.8%

Table 12-16 shows the project status changes in more detail and how scheduled queue MW have changed between December 31, 2020, and December 31, 2021. For example, 105,287.0 MW entered the queue in 2021. Of those 105,287.0 MW, 5,042.5 MW have been withdrawn. Of the total 156,386.7 MW marked as active on December 31, 2020, 13,027.3 MW were withdrawn, 5,004.4 MW were suspended, 2,293.0 MW started construction, and 557.5 MW went into service by December 31, 2021. Analysis of projects that were suspended on December 31, 2020 show that 946.0 MW came out of suspension and are now active as of December 31, 2021.

Table 12-16 Change in project status (MW): December 31, 2020 to December 31, 2021

		Status at 12/31/2021				
Status at 12/31/2020	Total at 12/31/2020	Active	In Service	Under Construction	Suspended	Withdrawn
(Entered during 2021)	0.0	100,244.5	0.0	0.0	0.0	5,042.5
Active	156,386.7	135,504.5	557.5	2,293.0	5,004.4	13,027.3
In Service	72,723.3	0.0	72,721.2	0.0	0.0	2.1
Under Construction	9,570.7	12.1	3,233.1	6,303.6	0.0	21.9
Suspended	7,017.3	946.0	0.0	400.0	4,116.5	1,554.8
Withdrawn	410,672.5	90.0	0.0	0.0	0.0	410,582.5
Total	656,370.5	236,797.1	76,511.8	8,996.6	9,120.9	430,231.1

34 Expected completion dates are entered when the project enters the queue. Actual completion dates are generally different than expected completion dates.
35 Wind and solar capacity in Table 12-11 through Table 12-15 have not been adjusted to reflect derating.

On December 31, 2021, 254,914.6 MW were in generation request queues in the status of active, suspended or under construction. Table 12-17 shows each status by unit type. Of the 236,797.1 MW in the status of Active on December 31, 2021, 7,198.3 MW (3.0 percent) were combined cycle projects. Of the 8,996.6 MW in the status of under construction, 6,023.6 MW (67.0 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 236,797.1 MW in the status of Active on December 31, 2021, 31,703.9 MW (13.4 percent) were renewable hybrid projects. Of the 8,996.6 MW in the status of under construction, 5.7 MW (.006 percent) were renewable hybrid projects.

Table 12-17 Current project status (MW) by unit type: December 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	38,267.5	7,198.3	3,975.3	4.0	396.6	5.0	730.0	124.9	145.5	14.4	0.0	0.0	115,049.7	31,494.9	209.0	40.0	11.0	0.0	20.0	39,111.1	0.0	236,797.1
Suspended	34.0	5,486.0	1,518.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,481.0	128.0	0.0	0.0	0.0	0.0	0.0	367.6	106.3	9,120.9
Under Construction	0.0	6,023.6	335.0	13.0	0.0	3.0	0.0	0.0	44.0	0.0	0.0	0.0	2,426.3	5.7	0.0	36.0	0.0	0.0	0.0	110.0	0.0	8,996.6
Total	38,301.5	18,707.9	5,828.3	17.0	396.6	8.0	730.0	124.9	189.5	14.4	0.0	0.0	118,957.0	31,628.6	209.0	76.0	11.0	0.0	20.0	39,588.7	106.3	254,914.6

A significant shift in the distribution of unit types within the PJM footprint continues to develop as natural gas fired units and renewable, hybrid and other intermittent resources enter the queue and coal fired steam units retire. As of December 31, 2021, of the 254,914.6 MW in the generation request queues in the status of active, suspended or under construction, 118,957.0 (46.7 percent) were solar projects, 39,588.7 MW (15.5 percent) were wind projects, 24,561.6 MW (9.6 percent) were natural gas fired projects (including combined cycle units, CTs, RICE units, and natural gas fired steam units), 31,943.9 MW (12.5 percent) were renewable hybrid projects (solar + storage, solar + wind and wind + storage units), and 76.0 MW (0.03 percent) were coal fired steam projects.

As of December 31, 2021, there are 6,342.1 MW of coal fired steam units and 150.6 MW of natural gas units slated for deactivation between January 1, 2022, 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. The small but growing level of renewables, hybrids and other intermittents will also have increasingly significant impacts on the energy and capacity markets.

Table 12-18 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 December 31, 2021, there are 254,914.6 MW in queues that are not yet in service or withdrawn, of which 3.6 percent are suspended, 3.5 percent are under construction and 92.9 percent have not begun construction.

Table 12-18 Queue totals by status (MW): December 31, 2021[36]

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	4,292.4	0.0	0.0	14,958.8	19,251.2
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	1,171.6	0.0	0.0	17,961.8	19,133.4
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	777.5	0.0	0.0	16,218.6	16,996.1
U3 Expired 31-Oct-08	0.0	333.0	0.0	100.0	2,535.6	2,968.6
U4 Expired 31-Jan-09	0.0	85.2	0.0	0.0	4,945.0	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	1,132.0	0.0	0.0	3,822.7	4,954.7
V4 Expired 31-Jan-10	0.0	748.8	0.0	0.0	3,708.0	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	12.1	508.7	0.0	0.0	8,683.8	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	0.0	6,279.7	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	278.6	4,678.9	150.0	463.0	6,498.4	12,068.9
AA2 Expired 30-Apr-15	682.0	1,825.6	995.0	1,091.0	11,472.7	16,066.3
AB1 Expired 31-Oct-15	2,706.8	1,430.9	1,275.8	3,106.0	11,924.3	20,443.7
AB2 Expired 31-Mar-16	1,226.8	1,142.3	2,092.3	557.0	10,147.4	15,165.8
AC1 Expired 30-Sep-16	2,680.5	1,114.6	3,569.8	1,538.6	11,138.9	20,042.2
AC2 Expired 30-Apr-17	2,502.4	530.1	66.4	364.9	9,137.8	12,601.6
AD1 Expired 30-Sep-17	5,316.4	298.9	106.6	305.0	5,275.7	11,302.6
AD2 Expired 31-Mar-18	6,069.4	310.5	425.8	223.0	13,337.5	20,366.1
AE1 Expired 30-Sep-18	15,168.7	70.5	19.9	47.6	18,600.1	33,906.9
AE2 Expired 31-Mar-19	22,322.8	50.0	3.8	140.4	11,301.9	33,818.8
AF1 Expired 30-Sep-19	21,214.9	16.8	47.0	125.9	7,513.4	28,917.9
AF2 Expired 31-Mar-20	20,928.1	3.0	3.2	48.3	7,226.6	28,209.1
AG1 Expired 30-Sep-20	32,502.6	0.5	0.0	25.0	5,446.5	37,974.6
AG2 Expired 31-Mar-21	55,630.0	0.0	0.0	0.0	1,105.3	56,735.3
AH1 Expired 30-Sep-21	45,764.2	0.0	0.0	0.0	4,030.3	49,794.5
AH2 Opened 01-Oct-21	1,682.9	0.0	0.0	0.0	81.9	1,764.8
Total	236,797.1	76,511.8	8,996.6	9,120.9	430,231.1	761,657.5

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

Table 12-19 shows the projects with a status of active, suspended or under construction, by unit type, and control zone. As of December 31, 2021, 254,914.6 MW were in generation request queues for construction through 2029. Table 12-19 also shows the planned retirements for each zone.

Table 12-19 Queue totals for projects (active, suspended and under construction) by LDA, control zone and unit type (MW): December 31, 2021[37]

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	1,218.0	7.6	230.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	678.6	213.0	0.0	0.0	0.0	0.0	0.0	3,441.6	0.0	5,788.8	120.3
	DPL	694.0	451.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,319.9	170.0	0.0	0.0	0.0	0.0	0.0	7,671.5	0.0	11,306.4	410.0
	JCPLC	813.8	35.0	0.0	0.0	0.0	0.0	30.0	0.0	0.0	0.0	0.0	0.0	472.3	180.0	0.0	0.0	0.0	0.0	0.0	6,589.2	0.0	8,120.3	0.0
	PECO	0.0	5.0	0.0	0.0	0.0	0.0	0.0	0.0	44.0	0.0	0.0	0.0	108.3	5.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	162.3	0.0
	PSEG	1,467.0	51.1	675.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	62.4	22.6	0.0	0.0	5.0	0.0	0.0	1,300.0	0.0	3,583.1	120.2
	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	4,192.8	549.7	905.0	0.0	0.0	0.0	30.0	0.0	44.0	0.0	0.0	0.0	3,641.5	590.6	0.0	0.0	5.0	0.0	0.0	19,002.3	0.0	28,960.9	650.5
SWMAAC	BGE	998.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	45.5	0.0	0.0	0.0	154.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,198.9	0.0
	PEPCO	301.0	0.0	55.3	4.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	215.1	1,346.5	0.0	0.0	6.0	0.0	0.0	0.0	0.0	1,927.9	1,229.0
	SWMAAC Total	1,299.5	0.0	55.3	4.0	0.0	0.0	0.0	0.0	45.5	0.0	0.0	0.0	370.1	1,346.5	0.0	0.0	6.0	0.0	0.0	0.0	0.0	3,126.9	1,229.0
WMAAC	MEC	625.2	75.0	13.5	7.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,023.1	157.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,901.4	2.5
	PE	897.8	85.0	585.5	0.0	3.6	3.0	0.0	0.0	0.0	0.0	0.0	0.0	5,841.0	887.8	0.0	0.0	0.0	0.0	0.0	260.2	0.0	8,564.0	0.0
	PPL	540.2	106.6	0.0	0.0	0.0	0.0	700.0	0.0	100.0	0.0	0.0	0.0	2,423.6	677.2	0.0	0.0	0.0	0.0	0.0	416.9	90.0	5,054.5	333.9
	WMAAC Total	2,063.2	266.6	599.0	7.5	3.6	3.0	700.0	0.0	100.0	0.0	0.0	0.0	9,287.7	1,722.1	0.0	0.0	0.0	0.0	0.0	677.1	90.0	15,519.8	336.4
Non-MAAC	AEP	9,368.8	6,015.0	822.1	0.0	379.2	0.0	0.0	51.0	0.0	0.0	0.0	0.0	38,076.0	11,943.7	0.0	76.0	0.0	0.0	0.0	3,458.4	0.0	70,190.1	80.0
	APS	2,511.8	5,020.0	112.0	0.0	0.0	0.0	0.0	15.0	0.0	14.4	0.0	0.0	5,867.3	2,464.3	0.0	0.0	0.0	0.0	0.0	844.6	16.3	16,865.6	0.0
	ATSI	1,654.3	1,895.0	523.7	5.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5,909.3	800.8	0.0	0.0	0.0	0.0	0.0	816.1	0.0	11,604.7	659.0
	COMED	4,423.4	3,712.6	1,421.2	0.0	0.0	5.0	0.0	12.1	0.0	0.0	0.0	0.0	11,800.6	2,285.8	199.0	0.0	0.0	0.0	0.0	9,373.1	0.0	33,232.8	1,234.1
	DAY	340.0	1,150.0	43.5	0.0	13.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3,640.5	338.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5,526.7	0.0
	DUKE	277.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	679.9	40.0	10.0	0.0	0.0	0.0	0.0	0.0	0.0	1,007.1	1,300.0
	DLCO	155.0	0.0	208.5	0.0	0.0	0.0	0.0	46.8	0.0	0.0	0.0	0.0	58.9	37.5	0.0	0.0	0.0	0.0	20.0	0.0	0.0	526.7	565.0
	DOM	11,889.5	99.0	1,138.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	33,359.9	7,253.8	0.0	0.0	0.0	0.0	0.0	5,417.2	0.0	59,157.4	1,027.0
	EKPC	126.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5,835.2	2,626.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8,587.5	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	430.0	178.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	608.5	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	30,746.0	17,891.6	4,269.0	5.5	393.0	5.0	0.0	124.9	0.0	14.4	0.0	0.0	105,657.6	27,969.4	209.0	76.0	0.0	0.0	20.0	19,909.3	16.3	207,307.1	4,865.1
	Total	38,301.5	18,707.9	5,828.3	17.0	396.6	8.0	730.0	124.9	189.5	14.4	0.0	0.0	118,957.0	31,628.6	209.0	76.0	11.0	0.0	20.0	39,588.7	106.3	254,914.6	7,081.0

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.[38] 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 39,588.7 MW of wind resources to 6,413.4 MW, 118,957.0 MW of solar resources to 55,552.9 MW, 31,628.6 MW of solar + storage resources to 14,770.6 MW, 209.0 MW of solar + wind resources to 97.6 MW and 106.3 MW of wind + storage resources to 17.2 MW, the 254,914.6 MW currently under construction, suspended or active in the queue would be reduced to 141,276.7 MW.

Beginning with the 2023/2024 Delivery Year, unforced capacity for intermittent resources and limited duration resources will be determined by PJM's effective load carrying capability (ELCC) analysis. The PJM ELCC analysis will determine capacity derates by resource class. The unforced capacity derate for a specific resource will equal the product of the ELCC class rating and a resource specific performance factor. The 2023/2024 ELCC class rating for wind resources is 15.0 percent, for solar resources with tracking panels is 54.0 percent and for solar resources with fixed panels is 38.0 percent.[39] The ELCC class rating for battery or energy storage resources replaces the 10 hour rule that was previously used to determine the unforced capacity value for an energy storage resource. PJM defined four different energy storage classes differentiated by duration. The ELCC class rating is 83.0 percent for storage resources that can continuously generate energy at the nameplate capacity for four hours (four hour storage). The ELCC class rating is 98.0 percent for six hour storage and 100 percent for 8 hour storage and 10 hour storage.[40]

37 This data includes only projects with a status of active, under construction, or suspended.
38 See "PJM Manual 14B: PJM Region Transmission Planning Process," Rev. 51 (December 15, 2021).
39 *ELCC Class Ratings for 2023-2024 BRA*, PJM Interconnection L.L.C. (December 16, 2021) <https://www.pjm.com/planning/resource-adequacy-planning/effective-load-carrying-capability>
40 Additional information available in *PJM Manual 21A: Determination of Accredited UCAP Using Effective Load Carrying Capability Analysis*, PJM Interconnection L.L.C. (August 1, 2021).

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.[41] 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 12-20 and Table 12-21.

Table 12-20 shows the milestone status when projects were withdrawn, for all withdrawn projects. Of the 3,269 projects withdrawn as of December 31, 2021, 1,627 (49.8 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 3,269 projects withdrawn, 615 (18.8 percent) were withdrawn after the completion of a Construction Service Agreement.

Table 12-20 Last milestone at time of withdrawal: January 1, 1997 through December 31, 2021

Milestone Completed	Projects Withdrawn	Percent	Average Days	Maximum Days
Never Started	592	18.1%	77	868
Feasibility Study	1,035	31.7%	268	1,633
System Impact Study	724	22.1%	701	3,248
Facilities Study	303	9.3%	1,134	4,107
Construction Service Agreement (CSA) or beyond	615	18.8%	1,379	7,864
Total	3,269	100.0%		

Average Time in Queue

Table 12-21 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 1,095 days, or 3.0 years, between entering a queue and going into service. For withdrawn projects, there is an average time of 619 days, or 1.7 years, between entering a queue and withdrawing.

Table 12-21 Project queue times by status (days): December 31, 2021[42]

Status	Average (Days)	Standard Deviation	Minimum	Maximum
Active	576	492	8	5,401
In-Service	1,095	799	0	5,306
Suspended	1,549	753	457	4,841
Under Construction	1,662	721	654	4,599
Withdrawn	619	741	0	7,864

Table 12-22 presents information on the time in the stages of the queue for those projects not yet in service or already withdrawn. Of the 2,867 projects in the queue as of December 31, 2021, 199 (6.9 percent) had a completed feasibility study and 447 (15.6 percent) had a completed construction service agreement.

Table 12-22 Project queue times by milestone (days): December 31, 2021

Milestone Reached	Number of Projects	Percent of Total Projects	Average Days	Maximum Days
Under Review	1,271	44.3%	512	793
Feasibility Study	199	6.9%	529	1,208
System Impact Study	930	32.4%	853	2,284
Facilities Study	20	0.7%	1,506	2,983
Construction Service Agreement (CSA) or beyond	447	15.6%	1,379	5,401
Total	2,867	100.0%		

41 See "PJM Manual 14B: PJM Region Transmission Planning Process," Rev. 51 (December 15, 2021).
42 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 12-23 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 compared to the period prior to 2017 although there are significant exceptions. 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 600 days in 2019.

Table 12-23 Average time in queue (days) by fuel type and year submitted (In Service Projects): December 31, 2021[43]

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	600	544	
CC	1,310	1,551	1,663	1,419	1,175	1,052	746	908	309	512		
CT - Natural Gas	1,131	804	953	1,021	734	901	1,192	657	688	320	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	1,489	1,211	997	855	488	295	
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	1,205	1,463	1,443	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 12-24 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 any milestone completed beyond the FSA including a Construction Service Agreement (CSA), Interconnection Service Agreement (ISA), Upgrade Construction Service Agreement (UCSA) and Wholesale Market Participant Agreement (WMPA) as well as the historic completion rates for all projects including those withdrawn before reaching the SIS milestone.[44] 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, 12.8 percent of the queued MW have gone into service. The completion rate for battery projects increases to 35.2 percent when battery projects complete the facility study agreement and further increases to 41.8 percent when battery projects complete the construction service agreement. Of all battery projects to enter the queue, only 0.6 percent of the queued MW have gone into service.

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

44 All milestones after the FSA are included in the totals under the CSA headings of the tables within Section 12, "Generation and Transmission Planning".

Table 12-24 Historic completion rates (MW energy) by unit type for projects with a completed SIS, FSA and CSA: December 31, 2021

Unit Type	Completion Rate (SIS)	Completion Rate (FSA)	Completion Rate (CSA)	Completion Rate (ALL)
Battery	12.8%	35.2%	41.8%	0.6%
CC	32.3%	49.6%	75.6%	14.5%
CT - Natural Gas	65.4%	80.5%	85.3%	41.6%
CT - Oil	35.4%	59.6%	90.8%	25.4%
CT - Other	12.3%	18.6%	29.5%	8.4%
Fuel Cell	30.6%	31.6%	31.6%	30.2%
Hydro - Pumped Storage	100.0%	100.0%	100.0%	24.1%
Hydro - Run of River	42.8%	60.7%	68.1%	20.9%
Nuclear	35.2%	42.1%	51.3%	28.6%
RICE - Natural Gas	30.7%	42.8%	47.4%	25.9%
RICE - Oil	34.0%	59.7%	59.7%	26.2%
RICE - Other	89.0%	91.4%	92.0%	78.1%
Solar	18.0%	41.8%	51.3%	2.7%
Solar + Storage	0.0%	54.5%	54.5%	0.0%
Solar + Wind	0.0%	0.0%	0.0%	0.0%
Steam - Coal	13.6%	25.4%	37.5%	6.3%
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%	27.1%
Wind	0.2%	100.0%	100.0%	0.0%
Wind + Storage	0.0%	0.0%	0.0%	0.0%

On December 31, 2021, 254,914.6 MW were in generation request queues in the status of active, under construction or suspended. Of the total 254,914.6 MW in the queue, 151,857.1 MW (59.6 percent) have reached at least the SIS milestone and 103,057.5 MW (40.4 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 any milestone beyond the FSA, and using the overall completion rates for those projects that have not yet reached the SIS milestone), 41,074.4 MW (16.1 percent) of new generation in the queue are expected to go into service.

Table 12-25 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 December 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 December 31, 2021.

Table 12-25 Percent of all projects (MW energy) to go in service by unit type and year submitted to the queue: December 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%	53.6%	5.6%	2.2%	6.1%	1.2%	0.5%	N/A	0.0%
CT - Natural Gas	100.0%	98.3%	89.7%	23.5%	32.0%	0.2%	8.2%	16.8%	4.3%	0.9%	0.4%	0.0%
CT - Oil	100.0%	N/A	1.2%	0.0%	0.0%	N/A	N/A	N/A	0.0%	0.0%	0.0%	N/A
CT - Other	28.8%	27.1%	36.1%	100.0%	0.0%	100.0%	N/A	0.0%	N/A	N/A	N/A	0.0%
Fuel Cell	N/A	N/A	N/A	N/A	N/A	67.4%	12.5%	0.0%	N/A	0.0%	N/A	0.0%
Hydro - Pumped Storage	N/A	N/A	N/A	N/A	N/A	100.0%	N/A	N/A	0.0%	0.0%	N/A	0.0%
Hydro - Run of River	0.0%	0.0%	57.6%	49.6%	11.2%	N/A	100.0%	26.8%	100.0%	0.0%	0.0%	0.0%
Nuclear	15.5%	1.6%	0.0%	100.0%	N/A	N/A	0.0%	71.6%	0.0%	N/A	0.0%	N/A
RICE - Natural Gas	N/A	N/A	100.0%	66.7%	5.4%	6.2%	0.0%	5.4%	N/A	N/A	N/A	0.0%
RICE - Oil	0.0%	0.0%	N/A	N/A	N/A	30.8%	N/A	N/A	N/A	N/A	N/A	N/A
RICE - Other	100.0%	100.0%	100.0%	100.0%	79.7%	25.5%	2.8%	0.0%	100.0%	N/A	N/A	N/A
Solar	10.7%	7.1%	16.9%	24.4%	30.7%	22.2%	10.1%	1.6%	0.5%	0.0%	0.0%	0.0%
Solar + Storage	N/A	N/A	N/A	N/A	N/A	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Solar + Wind	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0.0%	0.0%
Steam - Coal	100.0%	0.0%	1.4%	68.4%	1.2%	23.4%	37.5%	100.0%	0.0%	0.0%	N/A	N/A
Steam - Natural Gas	N/A	N/A	N/A	100.0%	0.0%	100.0%	100.0%	100.0%	N/A	N/A	0.0%	N/A
Steam - Oil	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Steam - Other	0.5%	61.2%	16.6%	0.0%	0.0%	N/A	N/A	N/A	N/A	N/A	N/A	0.0%
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	N/A	N/A	N/A	N/A	N/A	N/A	0.0%	0.0%	N/A	N/A	N/A	N/A
All	11.7%	18.9%	26.5%	32.7%	34.3%	9.0%	6.0%	3.1%	0.6%	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 12-26 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 4,491 projects entered from January 2015 through December 2021, 3,344 projects (74.5 percent) were renewable. Of the 1,301 projects entered in 2021, 956 projects (73.5 percent) were renewable.

Table 12-26 Number of projects entered in the queue: December 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	545	152	697
2020	2	775	213	990
2021	0	956	345	1,301
Total	72	4,687	2,384	7,143

As of December 31, 2021, renewable projects make up 76.0 percent of all projects in the queue and those projects account for 75.1 percent of the nameplate MW currently active, suspended or under construction in the queue as of December 31, 2021 (Table 12-27).

Table 12-27 Queue details by fuel group: December 31, 2021

Fuel Group	Number of Projects	Percent of Projects	MW	Percent MW
Nuclear	6	0.2%	189.5	0.1%
Renewable	2,178	76.0%	191,352.4	75.1%
Traditional	683	23.8%	63,372.7	24.9%
Total	2,867	100.0%	254,914.6	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 12-24). Table 12-28 shows the total MW of all projects in the queue as of December 31, 2021, in the status of active, suspended and under construction, by unit type. Table 12-28 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 18,707.9 MW of combined cycle projects in the queue, 11,128.3 MW (59.5 percent) are expected to go in service based on historical completion rates as of December 31, 2021. Of the 191,372.4 MW of renewable projects in the queue, only 24,300.6 MW (12.7 percent) are expected to go in service based on historical completion rates. Of the 191,372.4 MW of renewable projects in the queue, only 9,781.6 MW (5.1 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 12-28 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): December 31, 2021

Unit Type	MW in Queue	Completion Rate Adjusted MW in Queue	Completion Rate and Derate Adjusted MW in Queue
Battery	38,301.5	1,460.5	1,460.5
CC	18,707.9	11,128.3	11,128.3
CT - Natural Gas	5,828.3	4,025.0	4,025.0
CT - Oil	17.0	13.2	13.2
CT - Other	396.6	33.3	33.3
Fuel Cell	8.0	2.5	2.5
Hydro - Pumped Storage	730.0	707.2	707.2
Hydro - Run of River	124.9	56.8	56.8
Nuclear	189.5	73.8	73.8
RICE - Natural Gas	14.4	3.7	3.7
RICE - Oil	0.0	0.0	0.0
RICE - Other	0.0	0.0	0.0
Solar	118,957.0	16,424.1	7,670.1
Solar + Storage	31,628.6	618.6	288.9
Solar + Wind	209.0	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	20.0	5.4	5.4
Wind	39,588.7	6,485.9	1,050.7
Wind + Storage	106.3	0.0	0.0
Total	254,914.6	41,074.4	26,555.3

Queue Analysis by Unit Type and Project Classification

Table 12-29 shows the current status of all generation queue projects by unit type and project classification from January 1, 1997, through December 31, 2021. As of December 31, 2021, 7,143 projects, representing 761,657.5 MW, have entered the queue process since its inception. Of those, 1,007 projects, representing 76,511.8 MW, went into service. Of the projects that entered the queue process, 3,269 projects, representing 430,231.1 MW (56.5 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 5,696 projects have been classified as new generation and 1,447 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 5,613 projects (78.6 percent) of all 7,143 generation queue projects to enter the queue since January 1, 1997.

Table 12-29 Status of all generation queue projects: January 1, 1997 through December 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	24	62	48	10	25	3	0	10	2	10	0	55	182	1	0	8	5	0	4	97	0	546
	Upgrade	7	108	111	15	5	0	3	19	42	9	2	16	38	0	0	55	10	0	8	13	0	461
Under Construction	New Generation	0	5	1	0	0	0	0	0	0	0	0	0	29	2	0	0	0	0	0	1	0	38
	Upgrade	0	7	16	8	0	1	0	0	1	0	0	0	11	1	0	1	0	0	0	0	0	46
Suspended	New Generation	4	7	2	0	0	0	0	0	0	0	0	0	37	5	0	0	0	0	0	2	1	58
	Upgrade	0	5	2	0	0	0	0	0	0	0	0	0	6	0	0	0	0	0	0	0	1	14
Withdrawn	New Generation	194	432	29	10	81	26	2	43	9	29	12	16	1,437	78	0	55	1	0	34	458	0	2,946
	Upgrade	50	98	15	13	13	2	0	5	13	0	2	3	61	1	0	15	0	0	2	30	0	323
Active	New Generation	327	6	5	0	6	0	2	6	0	1	0	0	1,365	290	2	0	1	0	1	96	0	2,108
	Upgrade	224	16	29	2	2	2	1	2	5	0	0	0	256	36	0	3	2	0	0	22	1	603
Total Projects	New Generation	549	512	85	20	112	29	4	59	11	40	12	71	3,050	376	2	63	7	0	39	654	1	5,696
	Upgrade	281	234	173	38	20	5	4	26	61	9	4	19	372	38	0	74	12	0	10	65	2	1,447

Table 12-30 shows the totals in Table 12-29 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 12-30 Status of all generation queue projects as a percent of total projects by classification: January 1, 1997 through December 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
In Service	New Generation	4.4%	12.1%	56.5%	50.0%	22.3%	10.3%	0.0%	16.9%	18.2%	25.0%	0.0%	77.5%
	Upgrade	2.5%	46.2%	64.2%	39.5%	25.0%	0.0%	75.0%	73.1%	68.9%	100.0%	50.0%	84.2%
Under Construction	New Generation	0.0%	1.0%	1.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Upgrade	0.0%	3.0%	9.2%	21.1%	0.0%	20.0%	0.0%	0.0%	1.6%	0.0%	0.0%	0.0%
Suspended	New Generation	0.7%	1.4%	2.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Upgrade	0.0%	2.1%	1.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Withdrawn	New Generation	35.3%	84.4%	34.1%	50.0%	72.3%	89.7%	50.0%	72.9%	81.8%	72.5%	100.0%	22.5%
	Upgrade	17.8%	41.9%	8.7%	34.2%	65.0%	40.0%	0.0%	19.2%	21.3%	0.0%	50.0%	15.8%
Active	New Generation	59.6%	1.2%	5.9%	0.0%	5.4%	0.0%	50.0%	10.2%	0.0%	2.5%	0.0%	0.0%
	Upgrade	79.7%	6.8%	16.8%	5.3%	10.0%	40.0%	25.0%	7.7%	8.2%	0.0%	0.0%	0.0%

Project Status	Project Classification	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
In Service	New Generation	6.0%	0.3%	0.0%	12.7%	71.4%	0.0%	10.3%	14.8%	0.0%	9.6%
	Upgrade	10.2%	0.0%	0.0%	74.3%	83.3%	0.0%	80.0%	20.0%	0.0%	31.9%
Under Construction	New Generation	1.0%	0.5%	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%	0.0%	0.7%
	Upgrade	3.0%	2.6%	0.0%	1.4%	0.0%	0.0%	0.0%	0.0%	0.0%	3.2%
Suspended	New Generation	1.2%	1.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.3%	100.0%	1.0%
	Upgrade	1.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	50.0%	1.0%
Withdrawn	New Generation	47.1%	20.7%	0.0%	87.3%	14.3%	0.0%	87.2%	70.0%	0.0%	51.7%
	Upgrade	16.4%	2.6%	0.0%	20.3%	0.0%	0.0%	20.0%	46.2%	0.0%	22.3%
Active	New Generation	44.8%	77.1%	100.0%	0.0%	14.3%	0.0%	2.6%	14.7%	0.0%	37.0%
	Upgrade	68.8%	94.7%	0.0%	4.1%	16.7%	0.0%	0.0%	33.8%	50.0%	41.7%

Table 12-31 shows the total MW of projects in the PJM generation queue by unit type and project classification. For example, the 458 new generation wind projects that have been withdrawn from the queue as of December 31, 2021, (as shown in Table 12-29) constitute 79,866.2 MW. The 432 new generation combined cycle projects that have been withdrawn in the same time period constitute 216,941.7 MW.

Table 12-31 Status of all generation (MW) in the generation queue: January 1, 1997 through December 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
In Service	New Generation	4.4%	12.1%	56.5%	50.0%	22.3%	10.3%	0.0%	16.9%	18.2%	25.0%	0.0%	77.5%
	Upgrade	2.5%	46.2%	64.2%	39.5%	25.0%	0.0%	75.0%	73.1%	68.9%	100.0%	50.0%	84.2%
Under Construction	New Generation	0.0%	1.0%	1.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Upgrade	0.0%	3.0%	9.2%	21.1%	0.0%	20.0%	0.0%	0.0%	1.6%	0.0%	0.0%	0.0%
Suspended	New Generation	0.7%	1.4%	2.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Upgrade	0.0%	2.1%	1.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Withdrawn	New Generation	35.3%	84.4%	34.1%	50.0%	72.3%	89.7%	50.0%	72.9%	81.8%	72.5%	100.0%	22.5%
	Upgrade	17.8%	41.9%	8.7%	34.2%	65.0%	40.0%	0.0%	19.2%	21.3%	0.0%	50.0%	15.8%
Active	New Generation	59.6%	1.2%	5.9%	0.0%	5.4%	0.0%	50.0%	10.2%	0.0%	2.5%	0.0%	0.0%
	Upgrade	79.7%	6.8%	16.8%	5.3%	10.0%	40.0%	25.0%	7.7%	8.2%	0.0%	0.0%	0.0%

Project Status	Project Classification	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
In Service	New Generation	6.0%	0.3%	0.0%	12.7%	71.4%	0.0%	10.3%	14.8%	0.0%	9.6%
	Upgrade	10.2%	0.0%	0.0%	74.3%	83.3%	0.0%	80.0%	20.0%	0.0%	31.9%
Under Construction	New Generation	1.0%	0.5%	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%	0.0%	0.7%
	Upgrade	3.0%	2.6%	0.0%	1.4%	0.0%	0.0%	0.0%	0.0%	0.0%	3.2%
Suspended	New Generation	1.2%	1.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.3%	100.0%	1.0%
	Upgrade	1.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	50.0%	1.0%
Withdrawn	New Generation	47.1%	20.7%	0.0%	87.3%	14.3%	0.0%	87.2%	70.0%	0.0%	51.7%
	Upgrade	16.4%	2.6%	0.0%	20.3%	0.0%	0.0%	20.0%	46.2%	0.0%	22.3%
Active	New Generation	44.8%	77.1%	100.0%	0.0%	14.3%	0.0%	2.6%	14.7%	0.0%	37.0%
	Upgrade	68.8%	94.7%	0.0%	4.1%	16.7%	0.0%	0.0%	33.8%	50.0%	41.7%

Table 12-32 shows the MW totals in Table 12-31 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, 63.4 percent of wind project MW classified as new generation have been withdrawn from the queue between January 1, 1997, and December 31, 2021.

Table 12-32 Status of all generation queue projects as percent of total MW in project classification: January 1, 1997 through December 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	
In Service	New Generation	4.4%	12.1%	56.5%	50.0%	22.3%	10.3%	0.0%	16.9%	18.2%	25.0%	0.0%	77.5%	
	Upgrade	2.5%	46.2%	64.2%	39.5%	25.0%	0.0%	75.0%	73.1%	68.9%	100.0%	50.0%	84.2%	
Under Construction	New Generation	0.0%	1.0%	1.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
	Upgrade	0.0%	3.0%	9.2%	21.1%	0.0%	20.0%	0.0%	0.0%	1.6%	0.0%	0.0%	0.0%	
Suspended	New Generation	0.7%	1.4%	2.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
	Upgrade	0.0%	2.1%	1.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
Withdrawn	New Generation	35.3%	84.4%	34.1%	50.0%	72.3%	89.7%	50.0%	72.9%	81.8%	72.5%	100.0%	22.5%	
	Upgrade	17.8%	41.9%	8.7%	34.2%	65.0%	40.0%	0.0%	19.2%	21.3%	0.0%	50.0%	15.8%	
Active	New Generation	59.6%	1.2%	5.9%	0.0%	5.4%	0.0%	50.0%	10.2%	0.0%	2.5%	0.0%	0.0%	
	Upgrade	79.7%	6.8%	16.8%	5.3%	10.0%	40.0%	25.0%	7.7%	8.2%	0.0%	0.0%	0.0%	
Project Status	Project Classification	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total			
In Service	New Generation	6.0%	0.3%	0.0%	12.7%	71.4%	0.0%	10.3%	14.8%	0.0%	9.6%			
	Upgrade	10.2%	0.0%	0.0%	74.3%	83.3%	0.0%	80.0%	20.0%	0.0%	31.9%			
Under Construction	New Generation	1.0%	0.5%	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%	0.0%	0.7%			
	Upgrade	3.0%	2.6%	0.0%	1.4%	0.0%	0.0%	0.0%	0.0%	0.0%	3.2%			
Suspended	New Generation	1.2%	1.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.3%	100.0%	1.0%			
	Upgrade	1.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	50.0%	1.0%			
Withdrawn	New Generation	47.1%	20.7%	0.0%	87.3%	14.3%	0.0%	87.2%	70.0%	0.0%	51.7%			
	Upgrade	16.4%	2.6%	0.0%	20.3%	0.0%	0.0%	20.0%	46.2%	0.0%	22.3%			
Active	New Generation	44.8%	77.1%	100.0%	0.0%	14.3%	0.0%	2.6%	14.7%	0.0%	37.0%			
	Upgrade	68.8%	94.7%	0.0%	4.1%	16.7%	0.0%	0.0%	33.8%	50.0%	41.7%			

Table 12-33 shows the project MW that entered the PJM generation queue by unit type and year of entry. Since 2016, 73.0 percent of all new projects entering the generation queue have been combined cycle (11.7 percent), wind (16.0 percent) or solar projects (45.3 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 December 31, 2021, 40,213.1 MW of renewable hybrid units have entered the queue.

Table 12-33 Queue project MW by unit type and queue entry year: January 1, 1997 through December 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	2,061.1	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	32,412.2
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	234.9	0.0	27,377.8
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	2,920.7	2.0	0.0	47.0	606.5	0.0	0.0	2,160.6	0.0	35,550.9
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	11,605.5	85.6	0.0	80.0	77.0	0.0	0.0	3,448.7	16.3	35,747.2
2017	24.6	5,477.6	691.0	0.0	4.1	2.7	0.0	20.5	39.1	97.1	0.0	33.8	13,652.9	424.9	0.0	14.0	17.0	0.0	0.0	5,137.0	90.0	25,726.4
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	19,734.0	4,573.9	0.0	49.0	0.0	0.0	0.0	17,710.4	0.0	58,053.7
2019	5,688.3	3,332.5	1,572.1	13.0	0.0	3.0	500.0	99.0	0.0	0.0	0.0	0.0	27,422.0	9,596.1	0.0	11.0	0.0	0.0	0.0	11,585.4	0.0	59,822.3
2020	11,163.9	0.0	846.6	4.0	0.0	0.0	0.0	80.2	100.0	0.0	0.0	0.0	37,421.7	10,391.9	199.0	0.0	11.0	0.0	0.0	6,915.9	0.0	67,134.1
2021	25,637.3	2,129.0	771.0	0.0	396.6	5.0	30.0	23.5	0.0	14.4	0.0	0.0	48,644.3	14,823.5	10.0	0.0	0.0	0.0	20.0	11,160.0	0.0	103,664.6
Total	45,544.3	290,259.5	19,946.4	3,145.3	1,876.9	16.3	1,620.0	3,043.4	13,266.3	669.3	104.2	589.4	169,900.2	39,897.8	209.0	36,781.1	986.5	0.0	1,836.7	131,858.6	106.3	761,657.5

Combined Cycle Project Analysis

Table 12-34 shows the status of all combined cycle projects by number of projects that entered PJM generation queues from January 1, 1997, through December 31, 2021, by zone. Of the 46 combined cycle projects classified as new generation or upgrade currently active, suspended or under construction in the PJM generation queue, 12 projects (26.1 percent) are located in the AEP Zone.

Table 12-34 Status of all combined cycle queue projects by zone (number of projects): January 1, 1997 through December 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	3	4	2	1	0	2	0	7	2	0	7	4	0	5	2	4	8	6	0	62
	Upgrade	3	12	9	5	0	5	0	0	0	16	5	0	6	3	0	13	4	4	9	14	0	108
Under Construction	New Generation	0	3	0	0	0	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	5
	Upgrade	0	4	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	1	1	0	7
Suspended	New Generation	0	1	2	2	0	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	7
	Upgrade	0	1	1	0	0	0	0	0	0	0	0	0	1	0	0	0	2	0	0	0	0	5
Withdrawn	New Generation	23	19	45	13	8	14	0	1	2	19	16	3	26	25	0	43	41	34	42	56	2	432
	Upgrade	7	7	9	4	0	4	0	1	0	11	5	0	7	7	0	3	5	5	8	15	0	98
Active	New Generation	0	2	2	0	0	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	6
	Upgrade	1	1	4	0	0	2	0	0	0	3	1	0	0	0	0	1	0	1	2	0	0	16
Total Projects	New Generation	24	29	52	19	10	20	1	3	2	26	18	3	33	29	0	48	43	38	50	62	2	512
	Upgrade	11	25	23	9	0	11	0	1	0	30	11	0	14	11	0	17	11	10	20	30	0	234

Table 12-35 shows the status of all combined cycle projects by MW that entered PJM generation queues from January 1, 1997, through December 31, 2021, by zone. Of the 18,707.9 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 (32.2 percent) are located in the AEP Zone.

Table 12-35 Status of all combined cycle queue projects by zone (MW): January 1, 1997 through December 31, 2021

		Project MW										
Project Status	Project Classification	ACEC	AEP	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL
In Service	New Generation	650.0	3,032.0	1,970.0	3,751.0	140.0	600.0	0.0	533.0	0.0	5,828.6	319.2
	Upgrade	229.0	384.0	939.7	344.0	0.0	633.6	0.0	0.0	0.0	978.0	102.0
Under Construction	New Generation	0.0	2,579.0	0.0	0.0	0.0	2,350.9	0.0	0.0	0.0	0.0	0.0
	Upgrade	0.0	916.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Suspended	New Generation	0.0	1,050.0	1,091.0	1,895.0	0.0	100.0	1,150.0	0.0	0.0	0.0	0.0
	Upgrade	0.0	35.0	45.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
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	13,921.0	5,145.4
	Upgrade	149.4	711.0	874.0	636.0	0.0	1,735.0	0.0	36.0	0.0	780.4	959.0
Active	New Generation	0.0	1,150.0	3,370.0	0.0	0.0	1,150.0	0.0	0.0	0.0	0.0	0.0
	Upgrade	7.6	285.0	514.0	0.0	0.0	111.7	0.0	0.0	0.0	99.0	451.0
Total Projects	New Generation	9,192.4	20,320.5	28,263.1	14,287.0	3,262.1	14,342.9	1,150.0	667.5	665.0	19,749.6	5,464.6
	Upgrade	386.0	2,331.0	2,372.7	980.0	0.0	2,480.3	0.0	36.0	0.0	1,857.4	1,512.0

Project Status	Project Classification	EKPC	JCPLC	MEC	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
In Service	New Generation	0.0	1,665.8	2,557.0	0.0	2,665.0	1,900.0	1,560.0	5,142.0	2,448.5	0.0	34,762.0
	Upgrade	0.0	110.0	83.9	0.0	1,075.5	142.3	228.6	1,320.0	845.9	0.0	7,416.5
Under Construction	New Generation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4,929.9
	Upgrade	0.0	0.0	75.0	0.0	0.0	0.0	0.0	51.6	51.1	0.0	1,093.7
Suspended	New Generation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5,286.0
	Upgrade	0.0	35.0	0.0	0.0	0.0	85.0	0.0	0.0	0.0	0.0	200.0
Withdrawn	New Generation	991.8	13,562.6	13,001.0	0.0	23,340.0	16,114.0	21,308.2	18,917.7	25,044.6	6.9	216,941.7
	Upgrade	0.0	378.0	1,742.0	0.0	240.0	1,040.6	229.1	703.0	2,217.9	0.0	12,431.4
Active	New Generation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5,670.0
	Upgrade	0.0	0.0	0.0	0.0	5.0	0.0	0.0	55.0	0.0	0.0	1,528.3
Total Projects	New Generation	991.8	15,228.4	15,558.0	0.0	26,005.0	18,014.0	22,868.2	24,059.7	27,493.1	6.9	267,589.6
	Upgrade	0.0	523.0	1,900.9	0.0	1,320.5	1,267.9	457.7	2,129.6	3,114.9	0.0	22,669.9

Combustion Turbine - Natural Gas Project Analysis

Table 12-36 shows the status of all combustion turbine natural gas projects by number of projects that entered PJM generation queues from January 1, 1997, through December 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 12-36 Status of all combustion turbine - natural gas generation queue projects by zone (number of projects): January 1, 1997 through December 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	1	3	6	0	2	1	0	2	4	2	4	9	0	48
	Upgrade	4	10	8	2	0	12	5	0	0	28	8	0	4	1	0	4	4	3	4	14	0	111
Under Construction	New Generation	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	1
	Upgrade	0	0	1	2	0	4	0	0	0	0	0	0	1	4	0	0	4	0	0	0	0	16
Suspended	New Generation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	1	0	2
	Upgrade	0	0	1	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2
Withdrawn	New Generation	1	6	0	0	2	1	1	0	0	4	0	1	1	0	0	1	5	0	1	5	0	29
	Upgrade	2	1	1	1	0	2	2	0	1	3	0	0	0	1	0	0	1	0	0	0	0	15
Active	New Generation	1	1	0	0	0	0	0	0	0	2	0	0	0	0	0	0	1	0	0	0	0	5
	Upgrade	2	2	1	5	0	9	2	0	1	1	0	0	0	0	0	0	1	5	0	0	0	29
Total Projects	New Generation	7	7	6	0	5	1	1	0	2	9	6	1	3	1	0	3	11	2	5	15	0	85
	Upgrade	8	13	12	10	0	28	9	0	2	32	8	0	5	6	0	4	10	8	4	14	0	173

Table 12-37 shows the status of all combustion turbine natural gas projects by MW that entered PJM generation queues from January 1, 1997, through December 31, 2021, by zone. Of the 5,828.3 MW of combustion turbine natural gas projects classified as new generation or upgrade currently active, suspended or under construction in the PJM generation queue, 1,421.2 MW (24.4 percent) are located in the COMED Zone.

Table 12-37 Status of all combustion turbine - natural gas queue projects by zone (MW): January 1, 1997 through December 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	14.4	1,081.0	1,140.0	0.0	520.0	10.0	0.0	559.0	361.9	5.0	150.9	925.9	0.0	6,327.8
	Upgrade	43.7	227.0	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	2,744.5
Under Construction	New Generation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	205.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	205.0
	Upgrade	0.0	0.0	12.0	5.0	0.0	87.0	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	130.0
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	463.0	0.0	0.0	675.0	0.0	1,138.0
	Upgrade	0.0	0.0	30.0	0.0	0.0	350.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	380.0
Withdrawn	New Generation	7.5	1,519.0	0.0	0.0	153.6	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	4,426.3
	Upgrade	165.5	6.0	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	619.5
Active	New Generation	230.0	700.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,138.0	0.0	0.0	0.0	0.0	0.0	0.0	18.0	0.0	0.0	0.0	0.0	2,086.0
	Upgrade	0.0	122.1	70.0	518.7	0.0	984.2	43.5	0.0	3.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	92.0	55.3	0.0	0.0	0.0	1,889.3
Total Projects	New Generation	598.2	2,219.0	1,176.0	0.0	176.6	10.0	104.0	0.0	219.4	3,288.8	1,140.0	73.0	522.1	10.0	0.0	559.5	1,169.7	5.0	170.8	2,741.0	0.0	14,183.1
	Upgrade	209.2	355.1	303.7	588.7	0.0	1,815.2	207.5	0.0	3.5	982.7	86.0	0.0	200.0	47.6	0.0	42.0	367.5	87.3	252.3	215.0	0.0	5,763.3

Wind Project Analysis

Table 12-38 shows the status of all wind generation projects, by number of projects that entered PJM generation queues from January 1, 1997, through December 31, 2021, by zone. Of the 121 wind projects classified as new generation or upgrade currently active, suspended or under construction in the PJM generation queue, 46 projects (38.0 percent) are located in the COMED Zone.

Table 12-38 Status of all wind generation queue projects by zone (number of projects): January 1, 1997 through December 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	19	17	0	0	26	0	0	0	3	0	0	0	0	0	0	23	0	8	0	0	97
	Upgrade	0	0	3	0	0	5	0	0	0	0	0	0	0	0	0	0	5	0	0	0	0	13
Under Construction	New Generation	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
	Upgrade	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Suspended	New Generation	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	1	0	0	2
	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	115	46	8	0	108	15	0	0	21	11	1	3	0	0	0	64	0	47	1	0	458
	Upgrade	2	2	7	0	0	8	0	0	0	3	0	0	0	0	0	0	6	0	2	0	0	30
Active	New Generation	6	18	5	3	0	36	0	0	0	7	11	0	5	0	0	0	2	0	2	1	0	96
	Upgrade	0	1	1	0	0	10	0	0	0	0	5	0	4	0	0	0	1	0	0	0	0	22
Total Projects	New Generation	25	152	69	11	0	170	15	0	0	32	22	1	8	0	0	0	89	0	58	2	0	654
	Upgrade	2	3	11	0	0	23	0	0	0	3	5	0	4	0	0	0	12	0	2	0	0	65

Table 12-39 shows the status of all wind projects by MW that entered PJM generation queues from January 1, 1997, through December 31, 2021, by zone. Of the 39,588.7 MW of wind projects classified as new generation or upgrade currently active, suspended or under construction in the PJM generation queue, 9,373.1 MW (23.7 percent) are located in the COMED Zone.

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

		Project MW										
Project Status	Project Classification	ACEC	AEP	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL
In Service	New Generation	7.5	3,544.6	1,314.6	0.0	0.0	4,088.9	0.0	0.0	0.0	322.5	0.0
	Upgrade	0.0	0.0	5.0	0.0	0.0	213.2	0.0	0.0	0.0	0.0	0.0
Under Construction	New Generation	0.0	0.0	110.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Suspended	New Generation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	300.3	0.0
	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	4,643.6	23,638.0	3,552.2	1,295.6	0.0	25,327.3	2,128.0	0.0	0.0	4,988.4	2,968.8
	Upgrade	5.0	370.0	119.4	0.0	0.0	755.7	0.0	0.0	0.0	114.0	0.0
Active	New Generation	3,441.6	3,441.7	527.0	816.1	0.0	8,887.3	0.0	0.0	0.0	5,116.9	6,686.2
	Upgrade	0.0	16.6	207.6	0.0	0.0	485.8	0.0	0.0	0.0	0.0	985.3
Total Projects	New Generation	8,092.7	30,624.3	5,503.8	2,111.7	0.0	38,303.5	2,128.0	0.0	0.0	10,728.1	9,655.0
	Upgrade	5.0	386.6	332.0	0.0	0.0	1,454.7	0.0	0.0	0.0	114.0	985.3

Project Status	Project Classification	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	1,047.0	0.0	226.5	0.0	0.0	10,551.6
	Upgrade	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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	110.0
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Suspended	New Generation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	67.3	0.0	0.0	367.6
	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	150.3	2,304.0	0.0	0.0	0.0	5,377.0	0.0	3,473.1	20.0	0.0	79,866.2
	Upgrade	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	0.0	4,259.2	0.0	0.0	0.0	159.9	0.0	349.6	1,300.0	0.0	34,985.5
	Upgrade	0.0	2,330.0	0.0	0.0	0.0	100.3	0.0	0.0	0.0	0.0	4,125.7
Total Projects	New Generation	150.3	6,563.2	0.0	0.0	0.0	6,583.9	0.0	4,116.5	1,320.0	0.0	125,880.8
	Upgrade	0.0	2,330.0	0.0	0.0	0.0	364.2	0.0	6.0	0.0	0.0	5,977.8

Solar Project Analysis

Table 12-40 shows the status of all solar generation projects by number of projects that entered PJM generation queues from January 1, 1997, through December 31, 2021, by zone. Of the 1,704 solar projects classified as new generation or upgrade currently active, suspended or under construction in the PJM generation queue, 402 projects (23.6 percent) are located in the DOM Zone.

Table 12-40 Status of all solar generation queue projects by zone (number of projects): January 1, 1997 through December 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	7	8	0	1	1	1	1	0	41	11	0	53	0	0	1	1	1	2	44	0	182
	Upgrade	1	2	3	0	0	0	0	2	0	7	9	0	10	0	0	0	1	0	3	0	0	38
Under Construction	New Generation	1	3	3	0	0	0	1	0	0	12	6	0	0	0	0	0	0	0	0	3	0	29
	Upgrade	0	1	0	0	0	0	0	0	0	5	1	0	0	0	0	0	0	0	0	4	0	11
Suspended	New Generation	0	0	13	2	0	0	0	0	0	11	1	1	0	5	0	0	4	0	0	0	0	37
	Upgrade	0	0	1	0	0	0	0	1	0	0	0	0	2	2	0	0	0	0	0	0	0	6
Withdrawn	New Generation	186	133	98	33	15	45	24	16	2	242	150	16	195	24	1	9	78	23	54	93	0	1,437
	Upgrade	3	4	3	4	0	6	1	0	0	18	1	0	9	1	0	0	5	3	0	3	0	61
Active	New Generation	25	268	116	73	5	67	33	10	4	320	52	61	32	41	2	7	150	11	82	6	0	1,365
	Upgrade	3	68	18	22	0	15	11	1	1	54	8	5	2	8	2	0	18	0	20	0	0	256
Total Projects	New Generation	221	411	238	108	21	113	59	27	6	626	220	78	280	70	3	17	233	35	138	146	0	3,050
	Upgrade	7	75	25	26	0	21	12	4	1	84	19	5	23	11	2	0	24	3	23	7	0	372

Table 12-41 shows the status of all solar projects by MW that entered PJM generation queues from January 1, 1997, through December 31, 2021, by zone. Of the 118,957.0 MW of solar projects classified as new generation or upgrade currently active, suspended or under construction in the PJM generation queue, 38,076.0 MW (32.0 percent) are located in the AEP Zone.

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

		Project MW										
Project Status	Project Classification	ACEC	AEP	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL
In Service	New Generation	62.0	114.7	112.3	0.0	1.1	9.0	2.5	125.0	0.0	1,938.6	130.4
	Upgrade	0.0	150.0	0.0	0.0	0.0	0.0	0.0	75.0	0.0	45.1	0.0
Under Construction	New Generation	2.6	300.0	38.2	0.0	0.0	0.0	400.0	0.0	0.0	1,353.6	249.6
	Upgrade	0.0	20.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	41.0	0.0
Suspended	New Generation	0.0	0.0	192.5	70.0	0.0	0.0	0.0	0.0	0.0	729.9	202.0
	Upgrade	0.0	0.0	15.9	0.0	0.0	0.0	0.0	10.0	0.0	0.0	0.0
Withdrawn	New Generation	2,097.0	8,990.4	2,623.7	1,725.5	121.6	3,386.2	1,923.9	689.4	33.0	13,430.2	2,590.9
	Upgrade	170.0	126.0	27.9	178.0	0.0	110.0	20.0	0.0	0.0	1,008.8	0.0
Active	New Generation	628.0	33,723.9	5,132.1	4,922.6	154.9	10,197.6	3,015.0	649.9	50.6	29,240.0	1,796.3
	Upgrade	48.0	4,032.1	488.6	916.7	0.0	1,603.0	225.5	20.0	8.3	1,995.4	72.0
Total Projects	New Generation	2,789.6	43,129.0	8,098.7	6,718.1	277.6	13,592.8	5,341.4	1,464.3	83.6	46,692.3	4,969.2
	Upgrade	218.0	4,328.1	532.4	1,094.7	0.0	1,713.0	245.5	105.0	8.3	3,090.3	72.0

Project Status	Project Classification	EKPC	JCPLC	MEC	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
In Service	New Generation	0.0	397.9	0.0	0.0	3.3	13.5	2.5	15.0	231.9	0.0	3,159.6
	Upgrade	0.0	14.3	0.0	0.0	0.0	0.0	0.0	10.0	0.0	0.0	294.4
Under Construction	New Generation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	17.5	0.0	2,361.5
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.8	0.0	64.8
Suspended	New Generation	95.0	0.0	47.0	0.0	0.0	60.2	0.0	0.0	0.0	0.0	1,396.5
	Upgrade	0.0	18.6	40.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	84.5
Withdrawn	New Generation	998.9	1,617.4	819.7	78.0	78.4	2,565.1	438.0	1,002.1	565.6	0.0	45,774.8
	Upgrade	0.0	23.8	15.0	0.0	0.0	30.0	3.6	0.0	1.3	0.0	1,714.4
Active	New Generation	5,512.2	444.9	783.1	340.0	108.3	5,316.5	215.1	2,111.5	41.1	0.0	104,383.9
	Upgrade	228.0	8.8	153.0	90.0	0.0	464.3	0.0	312.1	0.0	0.0	10,665.8
Total Projects	New Generation	6,606.1	2,460.2	1,649.8	418.0	190.0	7,955.2	655.7	3,128.6	856.1	0.0	157,076.3
	Upgrade	228.0	65.5	208.0	90.0	0.0	494.3	3.6	322.1	5.1	0.0	12,823.9

Renewable Hybrid Project Analysis

Table 12-42 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 December 31, 2021, by zone.[45] Of the 339 renewable hybrid projects currently active, suspended or under construction in the PJM generation queue, 75 projects (22.1 percent) are located in the AEP Zone.

Table 12-42 Status of all renewable hybrid generation queue projects by zone (number of projects): January 1, 1997 through December 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	1	0	0	0	0	0	0	0	0	0	0	3	0	0	1	0	1	0	0	6
	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	5	5	0	5	0	0	0	26	0	8	0	1	0	0	4	1	1	8	0	78
	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	3	67	28	11	0	14	7	2	2	66	3	25	5	7	1	1	15	2	32	1	0	292
	Upgrade	1	7	2	2	0	2	3	0	0	6	0	3	0	1	0	0	3	0	7	0	0	37
Total Projects	New Generation	7	77	34	16	0	19	7	2	2	92	3	33	5	11	1	1	20	3	34	12	0	379
	Upgrade	1	8	3	2	0	2	3	0	0	6	0	3	0	2	0	0	3	0	7	0	0	40

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

Table 12-43 shows the status of all renewable hybrid projects by MW that entered PJM generation queues from January 1, 1997, through December 31, 2021, by zone. Of the 31,943.9 MW of renewable hybrid generation currently active, suspended or under construction in the PJM generation queue, 11,943.7 MW (37.4 percent) are located in the AEP Zone.

Table 12-43 Status of all renewable hybrid generation queue projects by zone (MW): January 1, 1997 through December 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	20.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	105.0	0.0	0.0	3.0	0.0	90.0	0.0	0.0	218.0
	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	375.0	334.9	0.0	629.9	0.0	0.0	0.0	2,114.9	0.0	1,004.0	0.0	20.0	0.0	0.0	180.5	20.0	180.0	29.9	0.0	8,264.4
	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	153.0	11,320.5	2,444.3	770.8	0.0	2,464.8	298.9	50.0	37.5	7,099.8	170.0	2,491.3	180.0	52.1	178.5	5.0	846.6	1,346.5	451.0	20.0	0.0	30,380.5
	Upgrade	60.0	620.0	0.0	30.0	0.0	20.0	40.0	0.0	0.0	154.0	0.0	135.0	0.0	0.0	0.0	0.0	38.2	0.0	226.2	0.0	0.0	1,323.4
Total Projects	New Generation	167.5	14,681.3	2,839.3	1,105.7	0.0	3,094.7	298.9	50.0	37.5	9,214.7	170.0	3,495.3	180.0	177.1	178.5	5.0	1,030.2	1,366.5	721.0	53.5	0.0	38,866.5
	Upgrade	60.0	623.2	16.3	30.0	0.0	20.0	40.0	0.0	0.0	154.0	0.0	135.0	0.0	3.7	0.0	0.0	38.2	0.0	226.2	0.0	0.0	1,346.6

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."[46] 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 12-44 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 December 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 761,657.5 MW that have entered the queue during the time period of January 1, 1997, through December 31, 2021, 71,432.6 MW (9.4 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 their own service territory. Of the 39,443.9 MW that entered the queue in the PSEG Zone during the time period of January 1, 1997, through December 31, 2021, 14,287.3 MW (36.2 percent) were submitted by PSEG or one of their affiliated companies.

46 See OATT § 1 (Transmission Owner).

Table 12-44 Relationship between project developer and transmission owner for all interconnection queue projects MW by unit type: December 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
AEP	AEP	Related	51	16.0	678.0	0.0	0.0	0.0	0.0	34.0	2.4	214.0	0.0	0.0	0.0
		Unrelated	1026	10,879.0	21,973.5	2,574.1	7.5	506.5	0.0	0.0	453.6	0.0	12.0	0.0	75.4
AES	DAY	Related	13	20.0	0.0	38.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	116	654.9	1,150.0	273.5	0.0	15.7	0.0	0.0	0.0	0.0	0.0	0.0	10.0
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
		Unrelated	42	175.0	665.0	222.9	40.0	19.2	0.0	0.0	194.6	1,879.0	0.0	0.0	0.0
DOM	DOM	Related	182	826.7	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
		Unrelated	1051	11,891.0	9,268.5	2,225.8	0.5	227.3	0.0	0.0	35.0	0.0	0.0	10.0	119.4
DUKE	DUKE	Related	12	37.3	36.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	42	355.4	667.5	0.0	0.0	0.0	0.0	0.0	112.0	0.0	0.0	0.0	4.8
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
		Unrelated	130	146.3	170.0	73.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
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
		Unrelated	370	1,339.0	8,848.4	807.4	388.0	20.7	2.8	0.0	0.0	0.0	2.0	5.0	10.3
	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
		Unrelated	73	1,236.6	3,012.1	166.6	18.0	133.0	0.0	0.0	0.4	3,280.0	1.3	0.0	0.0
	COMED	Related	17	0.0	0.0	296.0	0.0	0.0	0.0	0.0	0.0	1,185.0	0.0	0.0	0.0
		Unrelated	530	5,614.1	16,823.2	1,529.2	42.0	65.2	5.0	0.0	22.7	0.0	35.0	0.0	67.7
	DPL	Related	8	1.0	1,365.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	383	1,022.5	5,611.6	1,226.0	600.9	42.6	0.0	0.0	0.0	0.0	0.0	0.0	84.6
	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
		Unrelated	92	25.3	20,360.5	596.5	2.0	15.0	0.0	0.0	0.0	0.0	0.0	17.0	3.7
	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
		Unrelated	116	320.0	23,325.9	92.3	34.0	9.0	0.0	0.0	0.0	1,640.0	32.0	0.0	3.5
First Energy	APS	Related	7	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
		Unrelated	591	2,907.7	29,182.8	1,479.7	0.0	84.4	0.0	0.0	638.3	0.0	154.4	53.8	25.4
	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
		Unrelated	236	1,860.4	13,589.0	588.7	10.5	166.4	0.0	0.0	0.0	0.0	59.7	0.0	6.9
	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
		Unrelated	456	1,606.0	15,751.4	722.1	0.0	4.8	0.6	30.0	1.6	0.0	0.6	0.0	12.8
	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
		Unrelated	190	869.9	17,458.9	57.6	1,204.4	52.1	0.0	0.0	0.0	93.0	0.0	8.0	23.2
	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
		Unrelated	542	1,327.2	18,747.9	1,532.2	0.0	218.0	3.0	16.0	46.3	0.0	341.8	8.0	14.8
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
		Unrelated	6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
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
		Unrelated	416	870.0	23,928.3	423.1	8.0	234.5	0.0	1,200.0	142.6	488.0	19.9	2.4	44.7
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
		Unrelated	244	1,479.5	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
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
		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
Total		Related	489	964.5	40,946.4	4,217.8	189.5	0.0	0.0	374.0	396.4	5,886.3	0.0	0.0	68.5
		Unrelated	6654	44,579.8	249,313.1	15,728.6	2,955.8	1,876.9	16.3	1,246.0	2,647.0	7,380.0	669.3	104.2	520.9

Table 12-44 Relationship between project developer and transmission owner for all interconnection queue projects MW by unit type: December 31, 2021 (continued)

Parent Company	Transmission Owner	Related to Developer	Number of Projects	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
AEP	AEP	Related	51	299.7	180.0	0.0	3,918.0	90.0	0.0	0.0	0.0	0.0	5,432.1
		Unrelated	1026	47,157.4	15,124.5	0.0	10,399.0	0.0	0.0	452.0	31,010.9	0.0	140,625.3
AES	DAY	Related	13	21.5	0.0	0.0	1,347.5	0.0	0.0	0.0	0.0	0.0	1,427.0
		Unrelated	116	5,565.4	338.9	0.0	0.0	0.0	0.0	0.0	2,128.0	0.0	10,136.4
DUQ	DUQ	Related	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	42	91.9	37.5	0.0	2,810.0	0.0	0.0	20.0	0.0	0.0	6,155.1
DOM	DOM	Related	182	5,059.3	17.0	0.0	301.0	0.0	0.0	4.0	2,786.0	0.0	25,822.2
		Unrelated	1051	44,723.4	9,351.7	0.0	20.0	0.0	0.0	316.3	8,056.1	0.0	86,245.0
DUKE	DUKE	Related	12	106.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	179.7
		Unrelated	42	1,462.9	40.0	10.0	120.0	0.0	0.0	0.0	0.0	0.0	2,772.6
EKPC	EKPC	Related	2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	821.8
		Unrelated	130	6,834.1	3,630.3	0.0	0.0	0.0	0.0	0.0	150.3	0.0	11,003.9
Exelon	ACEC	Related	5	8.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	738.3
		Unrelated	370	2,999.3	227.5	0.0	15.0	5.5	0.0	10.0	8,097.7	0.0	22,778.6
	BGE	Related	15	20.0	0.0	0.0	10.0	101.0	0.0	0.0	0.0	0.0	530.5
		Unrelated	73	257.6	0.0	0.0	0.0	2.5	0.0	25.0	0.0	0.0	8,133.1
	COMED	Related	17	9.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,490.0
		Unrelated	530	15,296.8	2,915.7	199.0	1,926.0	91.0	0.0	90.0	39,758.1	0.0	84,480.8
	DPL	Related	8	7.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,373.4
		Unrelated	383	5,033.8	170.0	0.0	653.0	15.0	0.0	65.0	10,640.3	0.0	25,165.3
	PECO	Related	33	0.0	0.0	0.0	7.0	0.0	0.0	0.0	0.0	0.0	7,809.3
		Unrelated	92	190.0	5.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	21,215.0
	PEPCO	Related	1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.0
		Unrelated	116	659.3	1,366.5	0.0	0.0	6.0	0.0	0.0	0.0	0.0	27,488.5
First Energy	APS	Related	7	26.4	0.0	0.0	1,710.0	0.0	0.0	0.0	0.0	0.0	3,189.4
		Unrelated	591	8,604.7	2,839.3	0.0	4,092.0	0.0	0.0	184.4	5,835.8	16.3	56,098.9
	ATSI	Related	6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,694.0
		Unrelated	236	7,812.8	1,135.7	0.0	0.0	16.5	0.0	0.0	2,111.7	0.0	27,358.3
	JCPLC	Related	2	12.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	32.0
		Unrelated	456	2,513.7	180.0	0.0	0.0	0.0	0.0	30.0	8,893.2	0.0	29,746.7
	MEC	Related	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	190	1,857.8	180.8	0.0	0.0	0.0	0.0	84.0	0.0	0.0	21,889.7
	PE	Related	4	0.0	0.0	0.0	1,860.0	0.0	0.0	0.0	0.0	0.0	2,399.0
		Unrelated	542	8,449.6	1,068.4	0.0	561.0	590.0	0.0	525.0	6,948.1	0.0	40,397.0
OVEC	OVEC	Related	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	6	508.0	178.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	686.5
PPL	PPL	Related	22	124.8	0.0	0.0	111.0	0.0	0.0	0.0	0.0	0.0	4,205.8
		Unrelated	416	3,325.9	857.2	0.0	6,896.6	0.0	0.0	31.0	4,122.5	90.0	42,684.8
PSEG	PSEG	Related	109	180.4	3.7	0.0	24.0	44.0	0.0	0.0	0.0	0.0	14,287.3
		Unrelated	244	680.8	49.9	0.0	0.0	25.0	0.0	0.0	1,320.0	0.0	25,156.7
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
		Unrelated	2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6.9
Total		Related	489	5,875.1	200.7	0.0	9,288.5	235.0	0.0	4.0	2,786.0	0.0	71,432.6
		Unrelated	6654	164,025.1	39,697.1	209.0	27,492.6	751.5	0.0	1,832.7	129,072.6	106.3	690,224.9

Combined Cycle Project Developer and Transmission Owner Relationships

Table 12-45 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 December 31, 2021, by transmission owner and project status. Of the 48,202.1 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 December 31, 2021, 821.8 MW (82.9 percent) have been submitted by EKPC or one of their affiliated companies.

Table 12-45 Relationship between project developer and transmission owner for all combined cycle project MW in the queue: December 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	1,435.0	2,738.0	3,495.0	1,085.0	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	24.0	2,044.1	0.0	0.0	7,200.4	9,268.5
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	1,261.7	1,233.6	2,350.9	100.0	11,877.0	16,823.2
	DPL	Related	0.0	60.0	0.0	0.0	1,305.0	1,365.0
		Unrelated	451.0	361.2	0.0	0.0	4,799.4	5,611.6
	PECO	Related	0.0	0.0	0.0	0.0	6,965.0	6,965.0
		Unrelated	5.0	3,740.5	0.0	0.0	16,615.0	20,360.5
	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	3,884.0	2,384.7	0.0	1,136.0	21,778.1	29,182.8
	ATSI	Related	0.0	0.0	0.0	0.0	1,678.0	1,678.0
		Unrelated	0.0	4,095.0	0.0	1,895.0	7,599.0	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	0.0	2,042.3	0.0	85.0	16,620.6	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	7,123.3	32,935.0	5,972.5	5,486.0	197,796.2	249,313.1

Combustion Turbine – Natural Gas Project Developer and Transmission Owner Relationships

Table 12-46 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 December 31, 2021, by transmission owner and project status. Of the 9,407.3 CT – natural gas project MW that have achieved in service or under construction status during this time period, 1,794.0 (19.1 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 December 31, 2021, 1,818.1 MW (61.5 percent) have been submitted by PSEG or one of their affiliated companies.

Table 12-46 Relationship between project developer and transmission owner for all CT – natural gas project MW in the queue: December 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	822.1	227.0	0.0	0.0	1,525.0	2,574.1
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	14.4	205.0	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	0.0	13.0	0.0	0.0	153.6	166.6
	COMED	Related	296.0	0.0	0.0	0.0	0.0	296.0
		Unrelated	688.2	371.0	87.0	350.0	33.0	1,529.2
	DPL	Related	0.0	0.0	0.0	0.0	0.0	0.0
		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	55.3	37.0	0.0	0.0	0.0	92.3
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	518.7	40.0	5.0	0.0	25.0	588.7
	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	110.0	384.9	12.5	463.0	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	1,434.0	1,794.0	0.0	0.0	989.8	4,217.8
		Unrelated	2,541.3	7,278.3	335.0	1,518.0	4,056.0	15,728.6

Wind Project Developer and Transmission Owner Relationships

Table 12-47 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 December 31, 2021, by transmission owner and project status. Of the 10,900.3 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 DOM Zone during the time period of January 1, 1997, through December 31, 2021, 2,786.0 MW (25.7 percent) have been submitted by Dominion or one of their affiliated companies.

Table 12-47 Relationship between project developer and transmission owner for all wind project MW in the queue: December 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	3,458.4	3,544.6	0.0	0.0	24,008.0	31,010.9
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	9,373.1	4,302.1	0.0	0.0	26,082.9	39,758.1
	DPL	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	7,671.5	0.0	0.0	0.0	2,968.8	10,640.3
	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	734.6	1,319.6	110.0	0.0	3,671.6	5,835.8
	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	6,589.2	0.0	0.0	0.0	2,304.0	8,893.2
	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	260.2	1,067.5	0.0	0.0	5,620.3	6,948.0
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	67.3	3,479.1	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	36,471.1	10,778.3	110.0	367.6	81,345.6	129,072.6

Solar Project Developer and Transmission Owner Relationships

Table 12-48 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 December 31, 2021, by transmission owner and project status. Of the 5,880.3 solar project MW that have achieved in service or under construction status during this time period, 1,532.6 MW (26.1 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 861.2 MW that entered the queue in the PSEG Zone during the time period of January 1, 1997, through December 31, 2021, 180.4 MW (20.9 percent) have been submitted by PSEG or one of their affiliated companies.

Table 12-48 Relationship between project developer and transmission owner for all solar project MW in the queue: December 31, 2021

			MW by Project Status					
Parent Company	Transmission Owner	Related to Developer	Active	In Service	Under Construction	Suspended	Withdrawn	Total
AEP	AEP	Related	100.0	34.7	0.0	0.0	165.0	299.7
		Unrelated	37,656.0	230.0	320.0	0.0	8,951.4	47,157.4
AES	DAY	Related	0.0	0.0	0.0	0.0	21.5	21.5
		Unrelated	3,240.5	2.5	400.0	0.0	1,922.4	5,565.4
DUQ	DUQ	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	58.9	0.0	0.0	0.0	33.0	91.9
DOM	DOM	Related	3,465.4	896.4	445.6	0.0	251.9	5,059.3
		Unrelated	27,770.1	1,087.3	949.0	729.9	14,187.1	44,723.4
DUKE	DUKE	Related	50.0	0.0	0.0	0.0	56.4	106.4
		Unrelated	619.9	200.0	0.0	10.0	633.0	1,462.9
EKPC	EKPC	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	5,740.2	0.0	0.0	95.0	998.9	6,834.1
Exelon	ACEC	Related	0.0	0.0	0.0	0.0	8.3	8.3
		Unrelated	676.0	62.0	2.6	0.0	2,258.8	2,999.3
	BGE	Related	0.0	0.0	0.0	0.0	20.0	20.0
		Unrelated	154.9	1.1	0.0	0.0	101.6	257.6
	COMED	Related	0.0	9.0	0.0	0.0	0.0	9.0
		Unrelated	11,800.6	0.0	0.0	0.0	3,496.2	15,296.8
	DPL	Related	0.0	7.4	0.0	0.0	0.0	7.4
		Unrelated	1,868.3	123.0	249.6	202.0	2,590.9	5,033.8
	PECO	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	108.3	3.3	0.0	0.0	78.4	190.0
	PEPCO	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	215.1	2.5	0.0	0.0	441.6	659.3
First Energy	APS	Related	26.4	0.0	0.0	0.0	0.0	26.4
		Unrelated	5,594.3	112.3	38.2	208.4	2,651.6	8,604.7
	ATSI	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	5,839.3	0.0	0.0	70.0	1,903.5	7,812.8
	JCPLC	Related	0.0	0.0	0.0	0.0	12.0	12.0
		Unrelated	453.7	412.2	0.0	18.6	1,629.2	2,513.7
	MEC	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	936.1	0.0	0.0	87.0	834.7	1,857.8
	PE	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	5,780.9	13.5	0.0	60.2	2,595.1	8,449.6
OVEC	OVEC	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	430.0	0.0	0.0	0.0	78.0	508.0
PPL	PPL	Related	124.8	0.0	0.0	0.0	0.0	124.8
		Unrelated	2,298.9	25.0	0.0	0.0	1,002.1	3,325.9
PSEG	PSEG	Related	0.0	134.3	5.2	0.0	40.9	180.4
		Unrelated	41.1	97.6	16.1	0.0	526.0	680.8
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	3,766.5	1,081.8	450.8	0.0	576.0	5,875.1
		Unrelated	111,283.2	2,372.2	1,975.5	1,481.0	46,913.2	164,025.1

Renewable Hybrid Project Developer and Transmission Owner Relationships

Table 12-49 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 December 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 53.5 MW that entered the queue in the PSEG Zone during the time period of January 1, 1997, through December 31, 2021, 3.7 MW (6.9 percent) have been submitted by PSEG or one of their affiliated companies.

Table 12-49 Relationship between project developer and transmission owner for all hybrid project MW in the queue: December 31, 2021

			MW by Project Status					
Parent Company	Transmission Owner	Related to Developer	Active	In Service	Under Construction	Suspended	Withdrawn	Total
AEP	AEP	Related	180.0	0.0	0.0	0.0	0.0	180.0
		Unrelated	11,760.5	0.0	3.2	0.0	3,360.8	15,124.5
AES	DAY	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	338.9	0.0	0.0	0.0	0.0	338.9
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	7,236.8	0.0	0.0	0.0	2,114.9	9,351.7
DUKE	DUKE	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	50.0	0.0	0.0	0.0	0.0	50.0
EKPC	EKPC	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	2,626.3	0.0	0.0	0.0	1,004.0	3,630.3
Exelon	ACEC	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	213.0	0.0	0.0	0.0	14.5	227.5
	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	2,484.8	0.0	0.0	0.0	629.9	3,114.7
	DPL	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	170.0	0.0	0.0	0.0	0.0	170.0
	PECO	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	5.0	0.0	0.0	0.0	0.0	5.0
	PEPCO	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	1,346.5	0.0	0.0	0.0	20.0	1,366.5
First Energy	APS	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	2,444.3	0.0	0.0	36.3	375.0	2,855.6
	ATSI	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	800.8	0.0	0.0	0.0	334.9	1,135.7
	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	52.1	0.0	0.0	105.0	23.7	180.8
	PE	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	884.8	0.0	0.0	3.0	180.5	1,068.4
OVEC	OVEC	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	178.5	0.0	0.0	0.0	0.0	178.5
PPL	PPL	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	677.2	0.0	0.0	90.0	180.0	947.2
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	197.0	1.1	2.6	0.0	0.0	200.7
		Unrelated	31,506.9	0.0	3.2	234.3	8,268.1	40,012.4

Regional Transmission Expansion Plan (RTEP)[47]

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.[48] 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 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 cost/benefit ratio for the project. The cost/benefit 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 window was open from November 1, 2014, through February

47 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. 51 (December 15, 2021).

48 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>.

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.[49]

The fifth market efficiency cycle was performed for the 2020/2021 RTEP long term window. The 2020/2021 RTEP long term window was open from November 11, 2020, through May 11, 2021. This window accepted proposals to address historical congestion on four internal flowgates. PJM received 24 proposals from seven entities. Final project selections were made in the fourth quarter of 2021. The four projects selected will be presented to the PJM Board for approval in February 2022.

49 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.

The Cost/Benefit 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 cost/benefit 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 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 cost/benefit analysis. The current rules governing cost/benefit 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 cost/benefit analysis. PJM's cost/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 initially passed PJM's 1.25 cost/benefit 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 cost/benefit 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 cost/benefit 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.

PJM's 2019 study using simulations for years 2017, 2021, 2024 and 2027 had a cost benefit 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.

A portion of Project 9A in Pennsylvania was challenged in a proceeding at the Pennsylvania PUC. On May 20, 2021, the Pennsylvania PUC denied the Transource application to build in Pennsylvania based on failure to demonstrate need combined with negative economic and environmental effects.[50] Transource is appealing the decision at the state and federal level.[51]

On September 22, 2021, the PJM Board endorsed PJM's recommendation to suspend the Transource IEC (9A) Project, based on the rejection by the Pennsylvania PUC. Project 9A was removed from PJM's planning models pending future updates.[52]

While suspended, PJM is required by Schedule 6 of the Operating Agreement (OA) to "annually review the cost and benefits" of Board approved market efficiency projects that have not commenced construction or have not received state siting approval. Under Schedule 6,

50 See *Applications of Transource Pennsylvania, LLC for approval of the Siting and Construction of the 230 kV Transmission Line Associated with the Independence Energy Connection–East and West Projects in portions of York and Franklin Counties*, Pennsylvania et al., Opinion and Order, Docket No. A-2017-2640195 et al. (May 20, 2021).

51 See *Transource Pennsylvania, LLC et a. v. Pennsylvania Public Utility Commission*, Docket No. 689 CD 2021 (Commonwealth of Pennsylvania Court); *Transource Pennsylvania LLC v. Gladys Brown Dutrieuille*, et al, Docket No. 21-2567 (USDC M.D. Pa.).

52 Nick Dumitriu, Principal Engineer, PJM Market Simulation, Market Efficiency Update presented to the Transmission Expansion Advisory Committee (November 30, 2021) at 18 <https://www.pjm.com/-/media/committees-groups/committees/teac/2021/20211130/20211130-item-02-market-efficiency-update.ashx>.

PJM's 2021 study showed a cost/benefit ratio of 1.00 with a capital cost of $453.71 million. The sum of the positive (energy cost reductions) effects was $452.4 million, a reduction of $735.7 million (-61.9 percent) from the initial study. The sum of negative effects (energy cost increases) was $452.4 million, a reduction of $399.3 million (46.9 percent) in the negative effects from the -$851.7 results of the initial study. The net benefit of the project in the 2021 study was -$159.8 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 -0.35, not 2.10. The project should be rejected on these grounds rather than simply suspended.

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.[53] 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 cost/benefit analysis used for its own internal market efficiency projects which will, by definition, overstate project benefits 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.[54] 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 cost/benefit 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 cost/benefit 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 -$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 cost/benefit ratio of 0.32 to MISO, and a rejection of the project by MISO.

53 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>.

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

No interregional constraints were identified in either PJM or MISO's regional processes. Therefore, an IMEP study was not required during the 2020/2021 IMEP cycle.

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.[55] [56]

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.[57] 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.

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 cost/benefit ratio. PJM and MISO presented the five recommended projects to their boards in December 2017, and both boards approved all five projects.[58]

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 cost/benefit ratio. PJM and MISO presented the two recommended projects to their boards in December 2018, and both boards approved the projects.[59]

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. PJM and MISO agreed to assess the impact of planned upgrades and congestion using an additional year of market data. As a result, PJM and MISO did not conduct a TMEP study in 2021.

55 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>.

56 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).

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

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

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

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."[60] 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 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.[61] 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 12-50 and Table 12-51 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.

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

61 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).

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

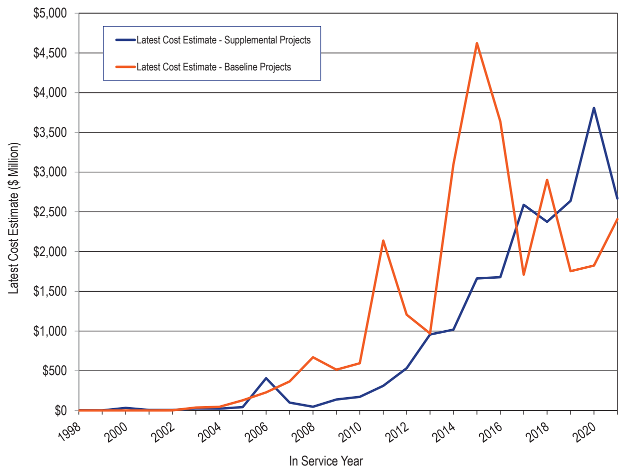


Table 12-50 shows the number of supplemental projects by expected in service year for each transmission zone. The average number of supplemental projects in each expected in service year increased by 770.0 percent, from 20 for years 1998 through 2007 (pre Order No. 890) to 174 for years 2008 through 2021 (post Order No. 890).

Table 12-50 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	NEET	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	0	3
1999	0	0	0	0	0	0	0	0	0	0	2	0	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	0	11
2001	0	0	0	0	0	0	0	0	0	0	14	0	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	0	10
2003	3	0	0	0	0	0	0	0	0	0	10	0	0	0	0	0	0	2	0	0	0	0	15
2004	5	0	10	0	0	9	0	0	0	0	12	0	2	0	0	0	0	0	0	0	2	0	40
2005	4	2	8	0	0	4	0	0	0	1	14	0	1	0	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	0	1	0	2	1	0	31
2007	1	1	5	0	4	5	0	0	4	0	6	0	0	0	0	0	0	2	0	1	6	0	35
2008	3	0	15	0	1	6	0	0	1	7	3	0	0	1	0	0	0	0	0	3	1	0	41
2009	3	1	6	0	1	8	0	0	3	3	5	0	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	0	2	0	0	3	5	0	42
2011	0	8	8	0	0	2	0	0	5	2	0	0	1	0	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	0	1	0	0	5	11	0	64
2013	5	21	4	5	0	11	0	6	4	13	1	0	1	1	0	0	1	0	1	14	19	0	107
2014	2	31	2	8	2	14	0	5	6	18	3	2	2	0	0	0	1	2	0	9	16	0	123
2015	4	15	2	9	1	37	0	8	4	17	5	4	2	0	0	0	1	0	4	7	24	0	144
2016	6	17	4	17	0	26	0	6	2	13	4	2	0	1	0	0	3	2	3	11	30	0	147
2017	8	107	3	26	1	23	0	3	8	31	11	5	0	3	0	0	0	3	1	22	43	0	298
2018	10	143	3	13	1	20	0	14	3	22	6	4	0	0	0	0	2	0	1	20	26	0	288
2019	3	159	4	30	5	14	2	17	1	33	8	5	3	14	0	0	1	15	0	15	27	0	356
2020	5	123	4	33	6	12	5	14	1	29	2	6	10	18	0	0	3	35	1	17	22	0	346
2021	4	141	6	36	6	3	9	14	2	27	1	8	14	35	0	5	19	32	0	20	21	0	403
2022	2	284	6	46	2	9	5	5	1	36	4	5	14	56	0	0	6	39	1	24	21	0	566
2023	6	250	3	16	0	4	18	8	1	23	3	5	1	10	1	0	3	36	3	21	27	0	439
2024	6	161	0	10	0	4	11	2	0	11	3	3	5	29	0	0	0	39	2	16	10	0	312
2025	4	112	1	6	3	0	7	0	0	28	5	1	0	22	0	0	0	24	0	6	19	0	238
2026	5	19	0	1	8	1	0	2	0	18	2	2	1	1	0	0	0	0	0	15	7	0	82
2027	1	26	0	3	1	0	0	1	2	0	1	1	0	1	0	0	0	1	0	26	0	0	64
2028	0	16	0	0	0	0	0	1	1	0	1	2	0	0	0	0	0	0	0	2	0	0	23
2029	0	0	0	0	4	0	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	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	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	0
2033	0	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	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	0
2036	0	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	0
2038	0	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	0
2040	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	94	1,650	112	264	50	224	57	113	58	351	160	55	61	194	1	5	53	237	17	269	346	0	4,371

Table 12-51 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 2,176.8 percent, from $64.6 million for years 1998 through 2007 (pre Order No. 890) to $1,470.8 million for years 2008 through 2021 (post Order No. 890).

Table 12-51 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	NEET	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	$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	$0.00	$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	$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	$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	$0.00	$7.00
2003	$7.42	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$8.77	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$9.60	$0.00	$0.00	$0.00	$0.00	$25.79
2004	$4.45	$0.00	$10.00	$0.00	$0.00	$0.82	$0.00	$0.00	$0.00	$0.00	$7.33	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$22.60
2005	$4.06	$14.67	$10.12	$0.00	$0.00	$2.57	$0.00	$0.00	$0.00	$0.02	$10.99	$0.00	$0.00	$0.00	$0.00	$0.00	$0.50	$0.00	$0.00	$0.00	$0.00	$0.00	$42.93
2006	$4.03	$309.70	$0.94	$0.00	$0.00	$48.93	$0.00	$0.00	$0.00	$0.00	$11.62	$0.00	$6.00	$0.00	$0.00	$0.00	$0.00	$1.50	$0.00	$4.63	$18.80	$0.00	$406.15
2007	$0.56	$2.06	$9.85	$0.00	$37.61	$4.65	$0.00	$0.00	$31.75	$0.00	$9.72	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.34	$2.28	$0.00	$98.82
2008	$2.36	$0.00	$12.03	$0.00	$0.45	$7.61	$0.00	$0.00	$7.00	$14.01	$2.27	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$1.60	$0.00	$0.00	$47.33
2009	$0.77	$0.90	$12.22	$0.00	$5.00	$21.11	$0.00	$0.00	$19.60	$2.12	$7.36	$0.00	$0.00	$0.00	$0.00	$0.00	$48.10	$2.73	$0.00	$0.16	$17.60	$0.00	$137.67
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	$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	$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	$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	$0.00	$22.50	$0.00	$2.40	$76.70	$503.72	$0.00	$956.63
2014	$8.03	$387.00	$5.97	$58.70	$21.20	$60.37	$0.00	$2.43	$14.90	$88.61	$5.96	$0.38	$5.60	$0.00	$0.00	$0.00	$13.30	$1.30	$0.00	$33.47	$309.71	$0.00	$1,016.93
2015	$3.73	$237.45	$3.80	$21.90	$2.00	$376.00	$0.00	$14.12	$4.53	$113.53	$13.06	$1.56	$0.30	$0.00	$0.00	$0.00	$33.80	$0.00	$42.50	$50.17	$743.91	$0.00	$1,662.36
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	$0.00	$86.40	$0.40	$7.80	$58.76	$744.18	$0.00	$1,677.44
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	$0.00	$8.30	$12.00	$264.34	$988.92	$0.00	$2,589.07
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	$0.00	$47.60	$0.00	$156.00	$197.34	$631.25	$0.00	$2,374.10
2019	$64.30	$1,162.53	$11.97	$190.40	$76.55	$90.19	$0.30	$99.19	$0.30	$90.14	$33.55	$23.67	$0.90	$62.30	$0.00	$0.00	$2.00	$75.80	$0.00	$298.00	$356.41	$0.00	$2,638.50
2020	$59.58	$782.03	$0.30	$112.78	$62.58	$78.09	$13.66	$86.86	$6.40	$258.32	$39.50	$25.61	$2.60	$23.70	$0.00	$0.00	$2.40	$74.50	$102.70	$215.29	$1,861.58	$0.00	$3,808.48
2021	$86.54	$936.09	$7.80	$206.84	$27.90	$125.70	$34.90	$158.79	$18.90	$77.24	$0.20	$28.14	$41.00	$144.39	$0.00	$4.40	$45.30	$72.36	$0.00	$196.23	$454.44	$0.00	$2,667.16
2022	$107.70	$1,749.90	$7.92	$295.00	$265.40	$118.40	$23.05	$38.25	$45.00	$331.96	$46.00	$11.18	$48.50	$155.24	$0.00	$0.00	$90.90	$93.73	$3.60	$283.30	$523.03	$0.00	$4,238.06
2023	$96.00	$1,986.49	$6.14	$194.68	$0.00	$25.40	$71.45	$64.32	$0.00	$141.11	$32.70	$29.69	$6.80	$78.90	$51.90	$0.00	$201.80	$86.00	$737.50	$362.34	$975.50	$0.00	$5,148.72
2024	$81.81	$1,405.93	$0.00	$177.53	$0.00	$212.40	$78.70	$17.64	$0.00	$239.57	$47.20	$30.55	$38.50	$186.66	$0.00	$0.00	$0.00	$93.30	$38.50	$252.00	$305.81	$0.00	$3,206.10
2025	$56.79	$943.99	$60.00	$199.70	$144.10	$0.00	$34.85	$0.00	$0.00	$385.07	$78.72	$1.05	$0.00	$115.20	$0.00	$0.00	$0.00	$51.00	$0.00	$127.00	$457.90	$0.00	$2,655.37
2026	$95.50	$201.10	$0.00	$19.60	$336.00	$67.00	$0.00	$13.30	$0.00	$328.40	$16.11	$21.90	$16.00	$26.40	$0.00	$0.00	$0.00	$0.00	$0.00	$387.80	$215.80	$0.00	$1,744.91
2027	$17.13	$377.53	$0.00	$389.30	$118.00	$0.00	$0.00	$23.97	$160.00	$0.00	$6.10	$13.74	$0.00	$10.00	$0.00	$0.00	$0.00	$138.00	$0.00	$582.41	$0.00	$0.00	$1,836.18
2028	$0.00	$365.44	$0.00	$0.00	$0.00	$0.00	$0.00	$17.90	$30.40	$0.00	$0.00	$30.78	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$51.00	$0.00	$0.00	$495.52
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	$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	$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	$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	$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	$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	$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	$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	$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	$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	$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	$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	$0.00
Total	$911.28	$12,666.51	$228.31	$2,369.73	$1,353.06	$1,848.53	$256.91	$722.00	$514.35	$2,669.39	$616.14	$231.58	$174.05	$828.54	$51.90	$4.40	$752.30	$908.52	$1,103.00	$3,664.77	$9,386.17	$0.00	$41,261.44

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.[62]

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.

62 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).

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.[63] 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.[64] 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.[65] 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.[66] 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.

63 See OA Schedule 6 § 1.5.8(m).
64 169 FERC ¶ 61,054 (2019).
65 See OA Schedule 6 § 1.5.8(n).
66 See OA Schedule 6 § 1.5.8(p).

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.[67]

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.[68] 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 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.[69]

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

67 170 FERC ¶ 61,243 (2020).
68 See "PJM Manual 14F: Competitive Planning Process," Rev. 8 (November 17, 2021).
69 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>.

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.[70] 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.[71]

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.[72]

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 2021, the PJM Board approved a net change of $1.11 billion in transmission upgrades. As of December 31, 2021, the PJM Board had approved $38.9 billion in transmission system enhancements since 1999. On February 22, 2021, the PJM Board authorized an additional $349.8 million in transmission upgrades and additions. On April 23, 2021, the PJM Board authorized an additional $330.7 million in transmission upgrades and additions. On July 30, 2021, the PJM Board authorized an additional $221.7 million in transmission upgrades and additions. On September 23, 2021, the PJM Board authorized an additional $77.0 million in transmission upgrades and additions. On December 2, 2021, the PJM Board authorized an additional $134.7 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 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 December 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

70 See *AEP*, Docket No. EL20-58 (July 22, 2020).
71 173 FERC ¶ 61,264 (2020).
72 Supplemental Projects, including the end of life subset of supplemental projects, do not require PJM Board of Managers authorization.

an alternative just and reasonable ex ante cost allocation method could be established for any such category of projects."[73] FERC convened a technical conference on January 12, 2016, to address the complaints in multiple proceedings and to address these two core issues.[74]

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.[75] 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.

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.[76]

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.

73 153 FERC ¶ 61,245 at P 35 (2015).
74 See Docket Nos. EL15-18-000 (ConEd), EL15-67-000 (Linden), and EL15-95-000 (Artificial Island).
75 170 FERC ¶ 61,122 (2020).
76 See the *2018 State of the Market Report for PJM*, Volume II, Section 11: Congestion and Marginal Losses.

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. The default transmission penalty factor is $2,000 per MWh.

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, generally results in at least a $2,000 per MWh price. As the power flows approach their rated limits, PJM dispatchers often reduce the limits.[77] Violation of these reduced line ratings results in penalty factors setting prices. In 2021, there were 170,067 transmission constraint intervals in the real-time market with a nonzero shadow price. For nearly eight percent of these transmission constraint intervals, the line limit was violated, meaning that the flow exceeded the facility limit. In 2021, the average shadow price of transmission constraints when the line limit was violated was nearly 8.8 times higher than when the transmission constraint was binding at its limit.[78]

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.[79]

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.[80] 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 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. [81]

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

77 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>.

78 See the *2020 State of the Market Report for PJM*, Volume II, Section 3: Energy Market.

79 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).

80 See "PJM Manual 3: Transmission Operations," Rev. 60 (November 17, 2021) § 2.1.1, at p 27.

81 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.

line ratings. New technologies that permit dynamic line ratings (DLR) should be implemented.

Line ratings determine the actual value of transmission in market operations. Yet the methods for defining line ratings remain opaque and vary significantly across transmission owners. Under defining line ratings results in over building transmission. Over defining line ratings results in less reliability than planned for. Dynamic line ratings are essential to reflect the actual availability of transmission in real time as ambient conditions change. Ensuring that system operators have accurate information about line ratings, including a wide range of line ratings by duration of load, are essential to ensure that all market participants receive the maximum value from the investment in the transmission system.

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. In PJM, real-time prices are calculated every five minutes for thousands of nodes. PJM prices are extremely sensitive to transmission line ratings.

The MMU recommends that all PJM transmission owners use the same methods to define line ratings and implement dynamic line ratings (DLR), subject to NERC standards and guidelines, subject to review by NERC, PJM and the MMU, 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.[82] 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.[83] All line rating changes and the detailed reasons for those changes should be public and fully transparent.

Order No. 881, issued December 16, 2021, requires: implementation by transmission providers of ambient-adjusted ratings on transmission lines; implementation by RTOs/ISOs of the systems and procedures necessary for hourly ratings updates; use of uniquely determined emergency ratings; sharing transmission line ratings and transmission line rating methods with RTOs/ISOs and market monitors; and maintenance of a database of transmission line ratings and transmission line rating methods on OASIS or other password-protected website. Order 881 did not require the use of dynamic line ratings based on an insufficient record.[84] But on February 17, 2022, in Docket No. AD22-5, FERC issued a notice of inquiry addressing the DLR issues.[85]

Dynamic Line Ratings (DLR) and GETs

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 relevant real time conditions include ambient air temperature, wind speeds, solar heating, transmission line tension, and transmission line sag. The widespread adoption of dynamic line ratings should be pursued. The adoption of dynamic line ratings does not require the exorbitant incentives proposed by some. Dynamic line rating technology and other Grid Enhancing Technology (GET) should be subject to competition and the costs of implementation should be capped at the costs that would result from the current cost of service method applied to transmission owners. The proposal that providers of GET should receive a share of forecast benefits is not consistent with competition, would pay rates of return many multiples of market rates of return and suffers from the same intractable problem of defining speculative benefits for long periods.

82 *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>.

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

84 *Managing Transmission Line Ratings*, Order No. 881, 177 FERC ¶ 61,179 at PP 25, 254 (2021) ("Order No. 881")

85 *Implementation of Dynamic Line Ratings*, Notice of Inquiry, 178 FERC ¶ 61,110 (2022).

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.[86] 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.[87] The specific timeline is shown in Table 12-53.[88]

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 2020/2021 planning period and the first seven months of the 2021/2022 planning period, regardless of when they were initially submitted.[89] The outage data for the day-ahead market are for outages scheduled to occur from 2015 through 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.[90] Table 12-52 shows that 74.8 percent of requested outages were planned for less than or equal to five days and 9.9 percent of requested outages were planned for greater than 30 days in the first seven months of 2021/2022 planning period. Table 12-52 also shows that 78.0 percent of the requested outages were planned for less than or equal to five days and 7.6 percent of requested outages were planned for greater than 30 days in the 2020/2021 planning period.

Table 12-52 Transmission facility outage request summary by planned duration: June 2020 through December 2021

	2020/2021 (12 months)		2021/2022 (7 months)	
Planned Duration (Days)	Outage Requests	Percent of Total	Outage Requests	Percent of Total
<=5	16,125	78.0%	8,039	74.8%
>5 & <=30	2,969	14.4%	1,647	15.3%
>30	1,578	7.6%	1,067	9.9%
Total	20,672	100.0%	10,753	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 12-53.[91]

The purpose of the rules defined in Table 12-53 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.[92]

Table 12-53 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

86 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. 60 (November 17, 2021).

87 See PJM, "Manual 3: Transmission Operations," Rev. 60 (November 17, 2021).

88 See PJM, "Manual 3: Transmission Operations," Rev. 60 (November 17, 2021).

89 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.

90 *Id.* at 70.

91 See PJM, "Manual 3: Transmission Operations," Rev. 60 (November 17, 2021).

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

Table 12-54 shows a summary of requests by received status. In the first seven months of 2021/2022 planning period, 43.6 percent of outage requests received were late. In the 2020/2021 planning period, 41.4 percent of outage requests received were late.

Table 12-54 Transmission facility outage requests by received status: June 2020 through December 2021

	2020/2021 (12 months)				2021/2022 (7 months)			
Planned Duration (Days)	On Time	Late	Total	Percent Late	On Time	Late	Total	Percent Late
<=5	9,912	6,213	16,125	38.5%	4,766	3,273	8,039	40.7%
>5 & <=30	1,577	1,392	2,969	46.9%	897	750	1,647	45.5%
>30	632	946	1,578	59.9%	406	661	1,067	61.9%
Total	12,121	8,551	20,672	41.4%	6,069	4,684	10,753	43.6%

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.[93]

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.[94] Table 12-55 is a summary of outage requests by emergency status. Of all outage requests scheduled to occur in the first seven months of 2021/2022 planning period, 13.0 percent were for emergency outages. Of all outage requests scheduled to occur in the 2020/2021 planning period, 12.2 percent were for emergency outages.

Table 12-55 Transmission facility outage requests by emergency: June 2020 through December 2021

	2020/2021 (12 months)				2021/2022 (7 months)			
Planned Duration (Days)	Emergency	Non Emergency	Total	Percent Emergency	Emergency	Non Emergency	Total	Percent Emergency
<=5	1,821	14,304	16,125	11.3%	1,020	7,019	8,039	12.7%
>5 & <=30	451	2,518	2,969	15.2%	196	1,451	1,647	11.9%
>30	251	1,327	1,578	15.9%	184	883	1,067	17.2%
Total	2,523	18,149	20,672	12.2%	1,400	9,353	10,753	13.0%

PJM will approve all transmission outage requests that are submitted on time and do not jeopardize the reliability of the PJM system. PJM will approve all transmission outage requests that are submitted late and are not expected to cause congestion on the PJM system and do not jeopardize the reliability of the PJM system. Each outage is studied and if it is expected to cause a constraint to exceed a limit, PJM will flag the outage ticket as "congestion expected."[95]

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 12-56 is a summary of outage requests by congestion status. Of all outage requests submitted to occur in the first seven months of 2021/2022 planning period, 6.6 percent were expected to cause congestion. Of all the outage requests that were expected to cause congestion, 3.2 percent (23 out of 711) were denied by PJM in the first seven months of 2021/2022 planning period and 19.7 percent (140 out of 711) were cancelled (Table 12-58). Of all outage requests submitted to occur in the 2020/2021 planning period, 6.3 percent were expected to cause congestion. Of all the outage requests that were expected to cause congestion, 1.6 percent (21 out of 1,296) were denied by PJM in the 2020/2021 planning period and 19.4 percent (251 out of 1,296) were cancelled (Table 12-58).

93 See PJM, "Manual 3: Transmission Operations," Rev. 60 (November 17, 2021). 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).

94 PJM, "Manual 3: Transmission Operations," Rev. 60 (November 17, 2021).

95 PJM added this definition to Manual 38 in February 2017. PJM, "Manual 38: Operations Planning," Rev. 14 (Jan. 27, 2021).

Table 12-56 Transmission facility outage requests by congestion: June 2020 through December 2021

	2020/2021 (12 months)				2021/2022 (7 months)			
Planned Duration (Days)	Congestion Expected	No Congestion Expected	Total	Percent Congestion Expected	Congestion Expected	No Congestion Expected	Total	Percent Congestion Expected
<=5	945	15,180	16,125	5.9%	509	7,530	8,039	6.3%
>5 & <=30	246	2,723	2,969	8.3%	127	1,520	1,647	7.7%
>30	105	1,473	1,578	6.7%	75	992	1,067	7.0%
Total	1,296	19,376	20,672	6.3%	711	10,042	10,753	6.6%

Table 12-57 shows the outage requests summary by received status, congestion status and emergency status. In the first seven months of 2021/2022 planning period, 30.8 percent of requests were submitted late and were nonemergency while 1.3 percent of requests (135 out of 10,753) were late, nonemergency, and expected to cause congestion. In the 2020/2021 planning period, 29.3 percent of request were submitted late and were nonemergency while 1.0 percent of requests (203 out of 20,671) were late, nonemergency, and expected to cause congestion.

Table 12-57 Transmission facility outage requests by received status, emergency and congestion: June 2020 through December 2021

		2020/2021 (12 months)				2021/2022 (7 months)			
Received Status		Congestion Expected	No Congestion Expected	Total	Percent of Total	Congestion Expected	No Congestion Expected	Total	Percent of Total
Late	Emergency	71	2,415	2,486	12.0%	33	1,340	1,373	12.8%
	Non Emergency	203	5,862	6,065	29.3%	135	3,176	3,311	30.8%
On Time	Emergency	2	35	37	0.2%	3	24	27	0.3%
	Non Emergency	1,020	11,064	12,084	58.5%	540	5,502	6,042	56.2%
Total		1,296	19,376	20,672	100.0%	711	10,042	10,753	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.[96] Table 12-58 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 12-58. Table 12-58 shows that of all the outage requests that were expected to cause congestion, 3.2 percent (23 out of 711) were denied by PJM in the first seven months of 2021/2022 planning period, 66.7 percent were complete and 19.7 percent (140 out of 711) were cancelled. Of all the outage requests that were expected to cause congestion, 1.6 percent (21 out of 1,296) were denied by PJM in the 2020/2021 planning period, 72.1 percent were complete and 19.4 percent (251 out of 1,296) were cancelled.

Table 12-58 Transmission facility outage requests by processed status: June 2020 through December 2021

		2020/2021 (12 months)						2021/2022 (7 months)					
Received Status		Cancelled	Complete	In Process	Denied	Congestion Expected	Percent Complete	Cancelled	Complete	In Process	Denied	Congestion Expected	Percent Complete
Late	Emergency	5	63	2	1	71	88.7%	3	29	0	1	33	87.9%
	Non Emergency	33	147	10	10	203	72.4%	23	90	7	12	135	66.7%
On Time	Emergency	0	2	0	0	2	100.0%	2	1	0	0	3	33.3%
	Non Emergency	213	722	68	10	1,020	70.8%	112	354	62	10	540	65.6%
Total		251	934	80	21	1,296	72.1%	140	474	69	23	711	66.7%

There are clear rules defined for assigning On Time or Late status for submitted outage requests in both the PJM tariff and PJM manuals.[97] However, the On Time or Late status only affects the priority that PJM assigns for processing the outage request. Table 12-58 shows that in the 2020/2021 planning period, 203 nonemergency outage requests were submitted late and expected to cause congestion. The expected impact on congestion is the basis for PJM's treatment of late outage requests. But there is no rule or clear definition of this congestion analysis in the PJM manuals. The

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

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 12-59 is a summary of all the outage requests planned for the 2020/2021 planning period and the first seven months of 2021/2022 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 seven months of 2021/2022 planning period, 30.7 percent of transmission outage requests were approved by PJM and then rescheduled by the TOs, and 12.6 percent of the transmission outages were approved by PJM and subsequently cancelled by the TOs. In the 2020/2021 planning period, 30.2 percent of transmission outage requests were approved by PJM and then rescheduled by the TO, and 12.3 percent of the transmission outages were approved by PJM and subsequently cancelled by the TO.

Table 12-59 Rescheduled and cancelled transmission outage requests: June 2020 through December 2021

	2020/2021 (12 months)					2021/2022 (7 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	16,125	3,537	21.9%	2,257	14.0%	8,039	1,753	21.8%	1,190	14.8%
>5 & <=30	2,969	1,674	56.4%	202	6.8%	1,646	873	53.0%	110	6.7%
>30	1,578	1,029	65.2%	81	5.1%	1,068	673	63.0%	50	4.7%
Total	20,672	6,240	30.2%	2,540	12.3%	10,753	3,299	30.7%	1,350	12.6%

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.[98] 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.[99] 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.

Long Duration Transmission Facility Outage Requests

PJM rules (Table 12-53) 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.

98 PJM, "Manual 3: Transmission Operations," Rev. 60 (November 17, 2021).

99 *Id.*

More than one outage request can be submitted for the same transmission equipment. In order to accurately present the results, Table 12-60 shows equipment outages by the equipment instead of by outage request.

Table 12-60 shows that there were 7,622 transmission equipment planned outages in the first seven months of 2021/2022 planning period, of which 1,042 or 13.7 percent were longer than 30 days, and of which 91 or 1.2 percent were scheduled longer than 30 days when the duration of all the outage requests are combined for the same equipment.

Table 12-60 Transmission equipment outages: June 2020 through December 2021

		2020/2021 (12 months)		2021/2022 (7 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	1,380	10.8%	951	12.5%
	Yes	239	1.9%	91	1.2%
<= 30		11,134	87.3%	6,580	86.3%
Total		12,753	100.0%	7,622	100.0%

Table 12-61 shows the details of long duration (> 30 days) outages when combining the duration of the outage requests for the same equipment.[100] 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 seven months of 2021/2022 planning period, within effective duration greater than a month and shorter than two months, there were 33 outages with a combined duration longer than 30 days.

Table 12-61 Transmission equipment outages by effective duration: June 2020 through December 2021

	2020/2021 (12 months)		2021/2022 (7 months)	
Effective Duration of Outage	Count of Equipment with Planned Outages	Percent of Total	Count of Equipment with Planned Outages	Percent of Total
<=31	2	0.8%	5	5.5%
>31 & <=62	23	9.6%	33	36.3%
>62 & <=93	18	7.5%	14	15.4%
>93	196	82.0%	39	42.9%
Total	239	100.0%	91	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.[101]

100 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.

101 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.

In the first seven months of 2021/2022 planning period, 278 outage requests were included in the annual FTR market outage list and 10,475 outage requests were not included.[102] In the 2020/2021 planning period, 321 outage requests were included in the annual FTR market outage list and 20,351 outage requests were not included. Table 12-62, Table 12-63, Table 12-64 and Table 12-65 show the summary information on the modeled outage requests and Table 12-66 and Table 12-67 show the summary information on outages that were not included in the Annual FTR Market.

Table 12-62 shows that 30.2 percent of the outage requests modeled in the Annual FTR Market for the first seven months of 2021/2022 planning period had a planned duration of less than two weeks and that 18.3 percent of the outage requests (51 out of 278) modeled in the Annual FTR Market for the planning period were submitted late according to outage submission rules. It also shows that 27.4 percent of the outage requests modeled in the Annual FTR Market for the 2020/2021 planning period had a planned duration of less than two weeks and that 16.5 percent of the outage requests (53 out of 321) modeled in the Annual FTR Market for the planning period were submitted late according to outage submission rules.

Table 12-62 Annual FTR market modeled transmission facility outage requests by received status: June 2020 through December 2021

	2020/2021 (12 months)				2021/2022 (7 months)			
Planned Duration	On Time	Late	Total	Percent of Total	On Time	Late	Total	Percent of Total
<2 weeks	76	12	88	27.4%	73	11	84	30.2%
>=2 weeks & <2 months	88	13	101	31.5%	84	13	97	34.9%
>=2 months	104	28	132	41.1%	70	27	97	34.9%
Total	268	53	321	100.0%	227	51	278	100.0%

Table 12-63 shows the annual FTR market modeled outage requests summary by emergency status and received status. None of the annual FTR market modeled outages expected to occur in the first seven months of 2021/2022 planning period were emergency outages. Two of the modeled outages expected to occur in the 2020/2021 planning period were emergency outages.

Table 12-63 Annual FTR market modeled transmission facility outage requests by emergency: June 2020 through December 2021

		2020/2021 (12 months)				2021/2022 (7 months)			
Received Status	Planned Duration	Emergency	Non Emergency	Total	Percent Non Emergency	Emergency	Non Emergency	Total	Percent Non Emergency
On Time	<2 weeks	0	76	76	100.0%	0	73	73	100.0%
	>=2 weeks & <2 months	0	88	88	100.0%	0	84	84	100.0%
	>=2 months	0	104	104	100.0%	0	70	70	100.0%
	Total	0	268	268	100.0%	0	227	227	100.0%
Late	<2 weeks	2	10	12	83.3%	0	11	11	100.0%
	>=2 weeks & <2 months	0	13	13	100.0%	0	13	13	100.0%
	>=2 months	0	28	28	100.0%	0	27	27	100.0%
	Total	2	51	53	96.2%	0	51	51	100.0%

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 12-64 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 seven months of 2021/2022 planning period and submitted late, 17.6 (9 out of 51) was expected to cause congestion. Overall, of all the annual FTR market modeled outages expected to occur in the 2020/2021 planning period and submitted late, 9.4 percent (5 out of 53) were expected to cause congestion.

102 PJM's treatment of transmission outages in the FTR models is discussed in the *2021 State of the Market Report for PJM*: Section 13: FTRs and ARRs: Supply and Demand.

Table 12-64 Annual FTR market modeled transmission facility outage requests by congestion: June 2020 through December 2021

		2020/2021 (12 months)				2021/2022 (7 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	17	59	76	22.4%	17	56	73	23.3%
	>=2 weeks & <2 months	19	69	88	21.6%	27	57	84	32.1%
	>=2 months	17	87	104	16.3%	12	58	70	17.1%
	Total	53	215	268	19.8%	56	171	227	24.7%
Late	<2 weeks	2	10	12	16.7%	1	10	11	9.1%
	>=2 weeks & <2 months	1	12	13	7.7%	5	8	13	38.5%
	>=2 months	2	26	28	7.1%	3	24	27	11.1%
	Total	5	48	53	9.4%	9	42	51	17.6%

Table 12-65 shows that 18.6 percent of outage requests modeled in the annual FTR market for the first seven months of 2021/2022 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 25.7 percent for the 2020/2021 planning period. Table 12-65 also shows that 16.5 percent of outages requests modeled in the Annual FTR Market for the first seven months of 2021/2022 planning period and with a duration of two months or longer were cancelled, compared to 17.4 percent for the 2020/2021 planning period.

Table 12-65 Annual FTR market modeled transmission facility outage requests by processed status: June 2020 through December 2021

		2020/2021 (12 months)		2021/2022 (7 months)	
Planned Duration	Processed Status	Outage Requests	Percent	Outage Requests	Percent
<2 weeks	In Progress	5	5.7%	13	15.5%
	Approved	0	0.0%	0	0.0%
	Cancelled	27	30.7%	24	28.6%
	Active	0	0.0%	0	0.0%
	Completed	56	63.6%	47	56.0%
	Total	88	100.0%	84	100.0%
>=2 weeks & <2 months	In Progress	7	6.9%	17	17.5%
	Approved	1	1.0%	1	1.0%
	Cancelled	26	25.7%	18	18.6%
	Active	0	0.0%	2	2.1%
	Completed	67	66.3%	59	60.8%
	Total	101	100.0%	97	100.0%
>=2 months	In Progress	14	10.6%	13	13.4%
	Approved	0	0.0%	0	0.0%
	Cancelled	23	17.4%	16	16.5%
	Active	3	2.3%	19	19.6%
	Completed	92	69.7%	49	50.5%
	Total	132	100.0%	97	100.0%
Total Cancelled		76	23.7%	58	20.9%
Grand Total		321		278	

More outage requests were not modeled in the Annual FTR Market than were modeled in the Annual FTR Market. In the first seven months of 2021/2022 planning period, 278 outage requests were modeled and 10,475 outage requests were not modeled in the Annual FTR Market. In the 2020/2021 planning period, 321 outage requests were modeled and 20,351 outage requests were not modeled in the Annual FTR Market.

Table 12-66 shows that 3.8 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 seven months of 2021/2022 planning period compared to 8.2 percent in the 2020/2021 planning period.

Table 12-66 Transmission facility outage requests not modeled in Annual FTR Auction: June 2020 through December 2021

	2020/2021 (12 months)						2021/2022 (7 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	1,997	8,610	81.2%	237	6,784	96.6%	1,739	3,419	66.3%	167	3,526	95.5%
>=2 weeks & <2 months	708	305	30.1%	154	809	84.0%	482	69	12.5%	111	442	79.9%
>=2 months	214	19	8.2%	194	320	62.3%	128	5	3.8%	173	214	55.3%
Total	2,919	8,934	75.4%	585	7,913	93.1%	2,349	3,493	59.8%	451	4,182	90.3%

Table 12-67 shows that 93.9 percent of late outage requests that 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, and were active or completed in the first seven months of 2021/2022 planning period. It also shows that 91.6 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 active or completed in the 2020/2021 planning period.

Table 12-67 Late transmission facility outage requests: June 2020 through December 2021

	2020/2021 (12 months)			2021/2022 (7 months)		
Planned Duration	Completed Outages	Total	Percent Complete	Completed Outages	Total	Percent Complete
<2 weeks	5,880	6,784	86.7%	3,056	3,526	86.7%
>=2 weeks & <2 months	707	809	87.4%	388	442	87.8%
>=2 months	293	320	91.6%	201	214	93.9%
Total	6,880	7,913	86.9%	3,645	4,182	87.2%

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.[103] Table 12-68 and Table 12-69 show the summary information on outage requests modeled in the Monthly Balance of Planning Period FTR Auction and Table 12-70 and Table 12-71 show the summary information on outage requests not modeled in the Monthly Balance of Planning Period FTR Auction.

103 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).

Table 12-68 shows that on average, 34.4 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 first seven months of 2021/2022 planning period. On average, 29.7 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 2020/2021 planning period.

Table 12-68 Monthly Balance of Planning Period FTR Auction modeled transmission facility outage requests by received status: June 2020 through December 2021

	2020/2021				2021/2022			
Month	On Time	Late	Total	Percent Late	On Time	Late	Total	Percent Late
Jun	215	101	316	32.0%	209	116	325	35.7%
Jul	96	71	167	42.5%	103	85	188	45.2%
Aug	118	81	199	40.7%	125	81	206	39.3%
Sep	468	140	608	23.0%	363	147	510	28.8%
Oct	596	176	772	22.8%	480	192	672	28.6%
Nov	486	185	671	27.6%	454	205	659	31.1%
Dec	324	130	454	28.6%	325	153	478	32.0%
Jan	224	64	288	22.2%				
Feb	211	116	327	35.5%				
Mar	429	142	571	24.9%				
Apr	477	174	651	26.7%				
May	412	180	592	30.4%				
Average	338	130	468	29.7%	294	140	434	34.4%

Table 12-69 shows that on average, 16.6 percent of outage requests modeled in the Monthly Balance of Planning Period FTR Auction were cancelled in the first seven months of 2021/2022 planning period. On average, 18.0 percent of outage requests modeled in the Monthly Balance of Planning Period FTR Auction were cancelled in the 2020/2021 planning period.

Table 12-69 Monthly Balance of Planning Period FTR Auction modeled transmission facility outage requests by processed status: June 2020 through December 2021

Planning Year	Month	In Process	Denied	Approved	Cancelled	Revised	Active	Complete	Total	Percent Cancelled
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%
	Apr	53	0	7	111	0	215	265	651	17.1%
	May	38	2	12	92	0	122	326	592	15.5%
	Average	43	3	12	84	0	130	196	468	18.0%
2021/2022	Jun	35	2	10	55	0	76	147	325	16.9%
	Jul	15	2	4	26	0	76	65	188	13.8%
	Aug	24	1	4	25	0	86	66	206	12.1%
	Sep	56	2	15	89	0	176	172	510	17.5%
	Oct	56	7	21	120	0	216	252	672	17.9%
	Nov	47	3	15	108	0	182	304	659	16.4%
	Dec	32	2	8	82	0	95	259	478	17.2%
	Average	38	3	11	72	0	130	181	434	16.6%

Table 12-70 shows that on average, 8.7 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 seven months of 2021/2022 planning period, compared to 9.7 percent in the 2020/2021 planning period. On average, 62.8 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 seven months of 2021/2022 planning period, compared to 65.5 percent in the 2020/2021 planning period.

Table 12-70 Transmission facility outage requests not modeled in Monthly Balance of Planning Period FTR Auction: June 2020 through December 2021

	2020/2021						2021/2022					
	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	798	105	11.6%	348	775	69.0%	778	85	9.8%	312	624	66.7%
Jul	430	90	17.3%	271	605	69.1%	349	69	16.5%	272	501	64.8%
Aug	437	75	14.6%	262	617	70.2%	371	43	10.4%	262	464	63.9%
Sep	1,061	87	7.6%	272	641	70.2%	943	96	9.2%	322	611	65.5%
Oct	1,187	75	5.9%	362	617	63.0%	1,043	69	6.2%	386	662	63.2%
Nov	961	74	7.1%	354	580	62.1%	867	43	4.7%	413	514	55.4%
Dec	737	69	8.6%	390	587	60.1%	681	26	3.7%	345	520	60.1%
Jan	595	84	12.4%	275	457	62.4%						
Feb	583	57	8.9%	275	575	67.6%						
Mar	1,346	81	5.7%	306	626	67.2%						
Apr	1,372	116	7.8%	383	645	62.7%						
May	1,189	108	8.3%	361	601	62.5%						
Average	891	85	9.7%	322	611	65.5%	719	62	8.7%	330	557	62.8%

Table 12-71 shows that on average, 70.2 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 seven months of 2021/2022 planning period, compared to 71.2 percent in the 2020/2021 planning period.

Table 12-71 Late transmission facility outage requests: June 2020 through December 2021

	2020/2021			2021/2022		
	Completed Outages	Total	Percent Complete	Completed Outages	Total	Percent Complete
Jun	564	775	72.8%	429	624	68.8%
Jul	436	605	72.1%	371	501	74.1%
Aug	447	617	72.4%	307	464	66.2%
Sep	436	641	68.0%	408	611	66.8%
Oct	419	617	67.9%	470	662	71.0%
Nov	392	580	67.6%	347	514	67.5%
Dec	440	587	75.0%	402	520	77.3%
Jan	341	457	74.6%			
Feb	390	575	67.8%			
Mar	440	626	70.3%			
Apr	475	645	73.6%			
May	437	601	72.7%			
Average	435	611	71.2%	391	557	70.2%

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.[104]

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.

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

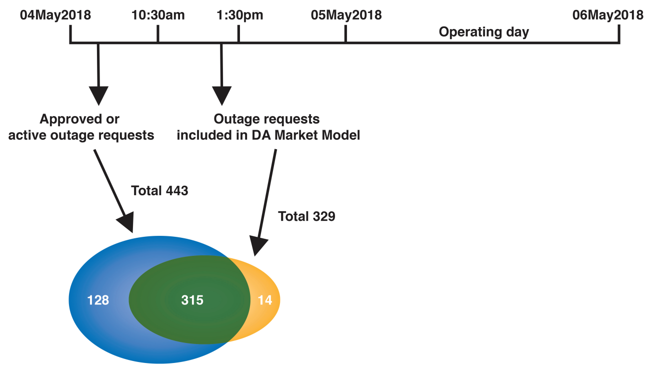
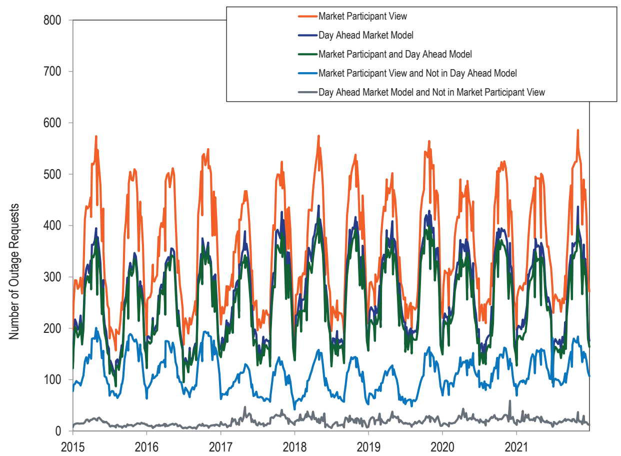


Figure 12-7 compares the weekly average number of active or approved outages available to market participants prior to the close of the day-ahead market with the outages included as inputs to the day-ahead market by PJM.

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



104 PJM, "Manual 3: Transmission Operations," Rev. 60 (November 17, 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: 2015 through 2021

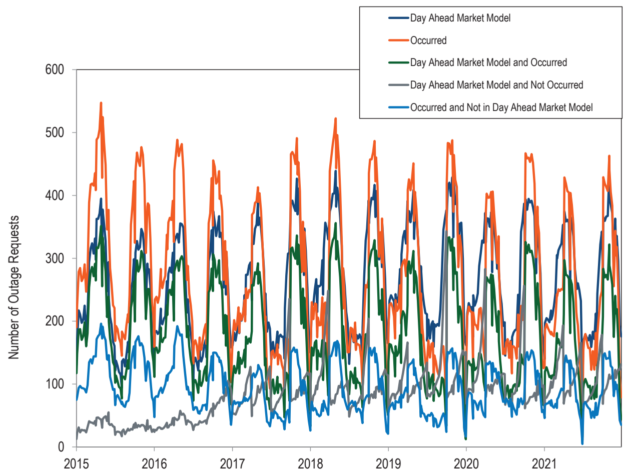


Figure 12-9 compares the weekly average number of active or approved outages available to market participants prior to the close of the day-ahead market with the outages that actually occurred during the operating day.

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

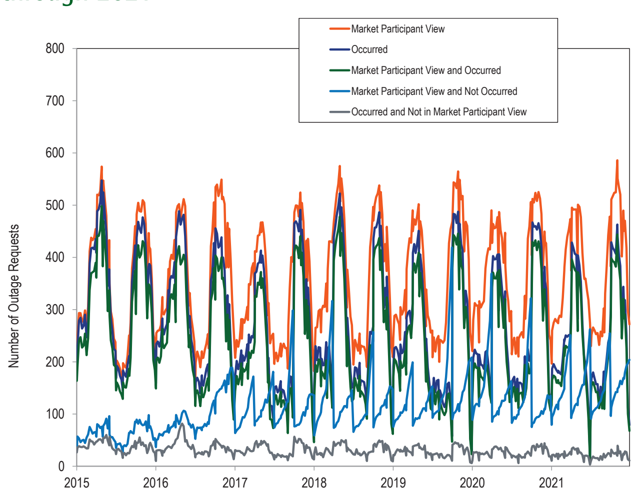


Figure 12-7, Figure 12-8, and Figure 12-9 show that on a weekly average basis, the active or approved outages available to day-ahead market participants, the outages included as inputs in the day-ahead market model and the outages that actually occurred in real time are not consistent. The active or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