Generation and Transmission Planning[1]

Overview

Generation Interconnection Planning

Existing Generation Mix

- As of December 31, 2022, PJM had a total installed capacity of 198,460.2 MW, of which 44,329.4 MW (22.3 percent) are coal fired steam units, 56,278.2 MW (28.4 percent) are combined cycle units and 33,452.6 MW (16.9 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 198,460.2 MW of installed capacity, 71,676.3 MW (36.1 percent) are from units older than 40 years, of which 34,642.3 MW (48.3 percent) are coal fired steam units, 191.0 MW (0.3 percent) are combined cycle units and 19,720.6 MW (27.5 percent) are nuclear units.

Generation Retirements[2]

- There are 53,187.8 MW of generation that have been, or are planned to be, retired between 2011 and 2024, of which 40,623.8 MW (76.4 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 2022, 6,164.3 MW of generation retired. The largest generator that retired in 2022 was the 638.0 MW Avon Lake Unit 9 coal fired steam unit located in the ATSI Zone. Of the 6,164.3 MW of generation that retired, 1,300.0 MW (21.1 percent) were located in the DUKE Zone.
- As of December 31, 2022, there are 5,695.8 MW of generation that have requested retirement after December 31, 2022, of which 1,522.2 MW (26.7 percent) are located in the ATSI Zone. Of the generation requesting retirement in the ATSI Zone, 1,490.0 MW (97.9 percent) are coal fired steam units.

Generation Queue[3]

- There were 254,998.8 MW in generation queues, in the status of active, under construction or suspended, at the end of 2021. In 2022, the AH2 queue window closed, the AI1 queue window opened and closed, and the AI2 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 As projects move through the queue process, projects can be removed from the queue due to incomplete or invalid data, withdrawn by the market participant or placed in service.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, 2022, there were 287,492.7 MW in generation queues, in the status of active, under construction or suspended, an increase of 32,493.9 MW (12.7 percent) from the end of 2021.[4]
- As of December 31, 2022, 7,702 projects, representing 818,390.6 MW, have entered the queue process since its inception in 1998. Of those, 1,060 projects, representing 81,305.0 MW, went into service. Of the projects that entered the queue process, 3,472 projects, representing 449,592.9 MW (54.9 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 21, 2022, 287,492.7 MW were in generation request queues in the status of active, under construction or suspended. Based on historical completion rates, 41,120.1 MW (14.3 percent) of new generation in the queue are expected to go into service.
- In 2022, 1,979.6 MW from the queue went in service. Of the 1,979.6 MW that went in service, 1,200.9 MW (60.7 percent) were combined cycle units, 625.2 MW (31.6 percent) were solar units and 153.5 MW (7.8 percent) were combustion turbine natural gas units.
- The number of queue entries increased during the past several years, primarily renewable projects. Of the 5,050 projects entered from January 2015 through December 2022, 3,742 projects (74.1 percent) were renewable. Of the 517 projects entered in 2022, 359 projects (69.4 percent) were renewable. Renewable projects make up 75.6 percent of all projects in the queue and those projects account for

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, 2022) <http://www.pjm.com/planning/services-requests/gen-deactivations.aspx>.
3 See PJM. Planning. "New Services Queue," (Accessed on December 31, 2022) <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.

75.2 percent of the nameplate MW currently active, suspended or under construction in the queue as of December 31, 2022.

But of the 216,192.4 MW of renewable projects in the queue, only 13,009.8 MW (6.0 percent) of capacity resources are expected to go into service, based on both historical completion rates and ELCC derate factors for battery, 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, 2022, PJM has completed five 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 855.0 percent, from 20 for years 1998 through 2007 (pre Order No. 890) to 191 for years 2008 through 2022 (post Order 890).[7]

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 2022, the PJM Board approved $2.6 billion in upgrades. As of December 31, 2022, the PJM Board has approved $41.5 billion in system enhancements since 1999.

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, 2022) <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.

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, 2022, 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 11,060 transmission outage requests submitted in the first seven months of the 2022/2023 planning period. Of the requested outages, 74.6 percent were planned for less than or equal to five days and 10.1 percent were planned for greater than 30 days. Of the requested outages, 40.1 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. (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.[11] (Priority: Medium. First reported 2013. Status: Partially adopted.)
- The MMU recommends continuing analysis of the study phase of PJM's transmission planning to reduce the need for postponements of study results, to decrease study completion times, and to improve the likelihood that a project at a given phase in the study process will successfully go into service.[12] (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

9 See "PJM Manual 03: Transmission Operations," Rev. 63 (November 16, 2022).

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>.

11 Once implemented, the approved solutions from PJM's Interconnection Process Reform Task Force (IPRTF) should result in improvements in these areas.

12 Ibid.

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.)[13]
- 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.)[14]
- The MMU recommends that PJM enhance the transparency and queue management process for nonincumbent transmission investment. Issues related to data access and complete explanations of cost impacts should be addressed. The goal should be to remove barriers to competition from nonincumbent transmission providers. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM continue to incorporate the principle that the goal of transmission planning should be the incorporation of transmission investment decisions into market driven processes as much as possible. (Priority: Low. First reported 2001. Status: Not adopted.)
- The MMU recommends the creation of a mechanism to permit a direct comparison, or competition, between transmission and generation alternatives, including which alternative is less costly and who bears the risks associated with each alternative. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM establish fair terms of access to rights of way and property, such as at substations, in order to remove any barriers to entry and permit competition between incumbent transmission providers and nonincumbent transmission providers in the RTEP. (Priority: Medium. First reported 2014. Status: Not adopted.)
- The MMU recommends that rules be implemented to permit competition to provide financing for transmission projects. This competition could reduce the cost of capital for transmission projects

13 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).

14 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).

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 changing the minimum distribution factor in the allocation from 0.01 to 0.00 and adding a threshold minimum usage impact on the line.[15] (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 core element of all 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 issued orders that are inconsistent with the recommendations of the MMU and that PJM cannot unilaterally modify those directives. It remains the recommendation of the MMU that the PJM rules for competitive transmission development through the RTEP should build upon FERC Order No. 1000 to create real competition between incumbent transmission providers and nonincumbent transmission providers. The ability of transmission owners to block competition for supplemental projects and end of life projects and the reasons for that policy should be reevaluated. PJM should enhance the transparency and queue management process for nonincumbent transmission investment. Issues

15 See *2015 State of the Market Report for PJM*, Volume II, Section 12: Generation and Transmission Planning, at 463, Cost Allocation 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 complex process. The PJM queue evaluation process will be significantly improved, based on the proposal submitted by PJM on June 14, 2022, and approved by FERC on November 29, 2022.[16] [17] The new rules include significant modifications to the interconnection process designed to address some of the key underlying issues and significantly improve the efficiency of the process. These modifications 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 proposed solution should help to reduce backlog and to remove projects that are not viable earlier to help improve the overall efficiency of the queue process.

The impact of the modifications to the queue process will need to be evaluated to determine if they successfully remove projects from the queue if they are not viable, and allow commercially viable projects to advance in the queue ahead of projects which have failed to make progress. 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 impacts of such behavior and the incentives for such behavior are addressed in the new process which includes nonrefundable fees, credit requirements, enhanced site control, elimination of the ability to suspend a project and milestone requirements. The impact of these aspects of the revised interconnection process should continue to be evaluated to ensure that they are having the desired effect on project developer behavior. 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 and whether transmission owners should perform interconnection studies.

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

16 See *PJM*, Docket No. ER22-2110 (June 14, 2022).
17 181 FERC ¶ 61,162 (2022).

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 plan, 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 and that have large and unnecessary impacts on the PJM 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.

The treatment by PJM and Dominion Virginia Power of the outage for the Lanexa – Dunnsville Line illustrates some of the issues with the current process. The outage was submitted and delayed more than once. PJM's analysis of expected congestion did not highlight the magnitude of the issue. Dominion Virginia Power did not stage the outage so as to minimize market disruption and congestion until after there were significant disruptions and congestion.

Generation Interconnection Planning

Existing Generation Mix

Table 12-1 shows the existing PJM capacity by control zone and unit type.[18] As of December 31, 2022, PJM had an installed capacity of 198,460.2 MW, of which 44,329.4 MW (22.3 percent) are coal fired steam units, 56,278.2 MW (28.4 percent) are combined cycle units

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

and 33,452.6 MW (16.9 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 198,460.2 MW of PJM installed capacity, 35,544.6 MW (17.9 percent) are in the AEP Zone, of which 13,463.0 MW (37.9 percent) are coal fired steam units, 10,494.0 MW (29.5 percent) are combined cycle units and 2,071.0 MW (5.8 percent) are nuclear units.

Table 12-1 Existing capacity: December 31, 2022 (By zone and unit type (MW))[19]

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	781.6	544.7	0.0	0.0	1.6	0.0	0.0	0.0	0.0	4.0	4.0	67.1	0.0	0.0	0.0	0.0	0.0	0.0	7.5	0.0	1,410.4
AEP	4.0	10,494.0	4,108.2	16.2	4.8	0.0	66.0	420.9	2,071.0	0.0	0.0	20.4	637.2	0.0	0.0	13,463.0	738.0	0.0	0.0	3,500.9	0.0	35,544.6
AMPT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
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	134.3	0.0	0.0	5,299.0	0.0	0.0	0.0	985.1	0.0	10,744.9
ATSI	0.0	4,647.5	958.0	608.0	6.4	0.0	0.0	0.0	2,134.0	0.0	18.5	24.8	0.0	0.0	0.0	1,490.0	325.0	0.0	136.0	0.0	0.0	10,348.2
BGE	0.0	0.0	267.6	228.8	0.0	0.0	0.0	0.0	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	4,393.2
COMED	109.0	3,471.1	6,673.3	226.2	0.0	0.0	0.0	0.0	10,473.5	0.0	0.0	15.0	9.0	0.0	0.0	2,646.0	1,326.0	0.0	0.0	5,031.0	0.0	29,980.1
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	36.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	967.6
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	1,252.0	47.0	0.0	0.0	0.0	0.0	2,810.0
DUQ	0.0	306.0	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	0.0	0.0	0.0	0.0	0.0	0.0	2,118.7
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	3,218.5	0.0	0.0	3,479.2	55.0	800.0	368.4	587.0	0.0	29,063.8
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	362.2	0.0	0.0	410.0	710.0	153.0	70.0	0.0	0.0	5,036.2
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	50.0	0.0	0.0	1,687.0	0.0	0.0	0.0	0.0	0.0	2,647.0
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	30.9	0.0	0.0	0.0	80.0	35.0	0.0	60.0	0.0	0.0	3,220.4
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	765.3	0.0	103.0	0.0	0.0	11,980.0
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	258.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8.7	2.5	0.0	0.0	0.0	1,164.1	0.0	52.0	0.0	0.0	3,986.0
PPL	20.0	5,558.5	286.6	36.0	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	14,457.4
PSEG	7.7	4,223.1	958.2	0.0	0.0	0.0	0.0	5.0	3,493.0	0.0	0.0	9.0	230.3	0.0	0.0	0.0	3.0	0.0	179.1	0.0	0.0	9,108.3
XIC	0.0	0.0	670.6	0.0	0.0	0.0	0.0	0.0	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	3,765.6
Total	307.5	56,278.2	24,421.3	3,687.9	43.8	32.0	4,792.0	2,771.1	33,452.6	176.1	218.5	308.0	5,396.0	0.0	0.0	44,329.4	8,370.9	1,350.0	1,096.5	11,428.4	0.0	198,460.2

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 198,460.2 MW of installed capacity, 48,193.9 MW (24.3 percent) are in Pennsylvania, of which 8,681.4 MW (18.0 percent) are coal fired steam units, 18,292.2 MW (38.0 percent) are combined cycle units and 8,843.8 MW (18.4 percent) are nuclear units.

Table 12-2 Existing capacity: December 31, 2022 (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	109.0	3,471.1	6,673.3	226.2	0.0	0.0	0.0	0.0	10,473.5	0.0	0.0	15.0	9.0	0.0	0.0	2,646.0	1,326.0	0.0	0.0	5,031.0	0.0	29,980.1
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	282.6	0.0	0.0	3,923.8	0.0	0.0	0.0	2,353.2	0.0	8,847.4
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	50.0	0.0	0.0	1,687.0	278.0	0.0	0.0	0.0	0.0	3,769.1
MD	20.0	2,717.0	1,684.5	502.7	0.0	0.0	0.0	0.0	1,716.0	0.0	76.0	18.9	385.1	0.0	0.0	1,758.0	1,307.6	550.0	109.0	295.0	0.0	11,139.8
MI	0.0	2,194.0	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	4,289.4
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	7,234.2	2,034.0	225.6	0.0	2.0	140.0	5.0	3,493.0	0.0	4.0	27.1	693.6	0.0	0.0	0.0	3.0	0.0	179.1	7.5	0.0	14,095.7
OH	22.0	10,634.7	4,201.2	680.2	6.4	0.0	0.0	200.0	2,134.0	0.0	47.0	29.6	386.1	0.0	0.0	8,310.0	47.0	0.0	136.0	1,147.7	0.0	27,981.9
PA	49.9	18,292.2	1,526.5	1,334.5	20.6	0.0	1,583.0	1,445.7	8,843.8	176.1	40.5	82.6	116.5	0.0	0.0	8,681.4	4,184.3	0.0	234.0	1,582.3	0.0	48,193.9
TN	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	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	2,442.0	0.0	0.0	2,474.2	515.0	800.0	368.4	12.0	0.0	27,616.1
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	670.6	0.0	0.0	0.0	0.0	0.0	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	3,765.6
Total	307.5	56,278.2	24,421.3	3,687.9	43.8	32.0	4,792.0	2,771.1	33,452.6	176.1	218.5	308.0	5,396.0	0.0	0.0	44,329.4	8,370.9	1,350.0	1,096.5	11,428.4	0.0	198,460.2

Table 12-3 and Figure 12-1 show the age of existing PJM generators, by unit type, as of December 31, 2022. Of the 198,460.2 MW of installed capacity, 71,676.3 MW (36.1 percent) are from units older than 40 years, of which 34,642.3 MW (48.3 percent) are coal fired steam units, 191.0 MW (0.3 percent) are combined cycle units and 19,720.6 MW (27.5 percent) are nuclear units.

19 The capacity described in this section refers to all capacity in PJM at the summer installed capacity rating, regardless of whether the capacity entered the RPM Auction.

Table 12-3 Capacity (MW) by unit type and age (years): December 31, 2022

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	307.5	45,914.2	5,015.3	0.0	43.8	32.0	0.0	293.6	0.0	164.1	20.0	224.7	5,396.0	0.0	0.0	3,475.0	82.0	0.0	47.4	11,338.4	0.0	72,354.0
20 to 40	0.0	10,173.0	18,901.7	960.0	0.0	0.0	3,003.0	318.4	13,732.0	12.0	25.0	83.3	0.0	0.0	0.0	6,212.1	76.3	0.0	843.1	90.0	0.0	54,429.9
40 to 60	0.0	191.0	504.3	2,727.9	0.0	0.0	1,789.0	452.0	19,720.6	0.0	173.5	0.0	0.0	0.0	0.0	31,940.5	6,173.1	1,350.0	0.0	0.0	0.0	65,021.9
Greater than 60	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,707.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,701.8	2,039.5	0.0	206.0	0.0	0.0	6,654.4
Total	307.5	56,278.2	24,421.3	3,687.9	43.8	32.0	4,792.0	2,771.1	33,452.6	176.1	218.5	308.0	5,396.0	0.0	0.0	44,329.4	8,370.9	1,350.0	1,096.5	11,428.4	0.0	198,460.2

Figure 12-1 Capacity (MW) by age (years): December 31, 2022

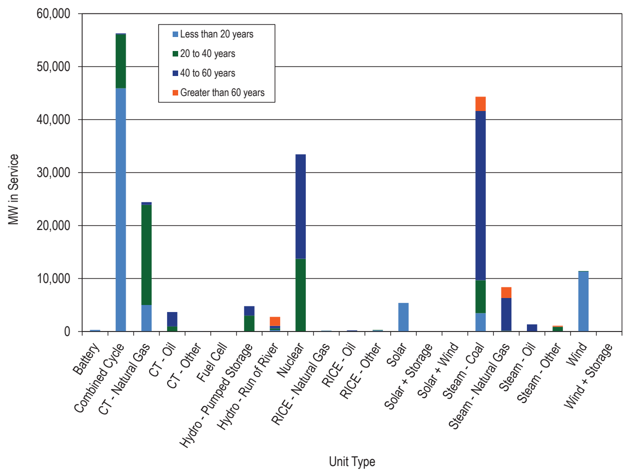


Figure 12-2 is a map of units, less than 20 MW in size that came online between January 1, 2011, and December 31, 2022. A mapping to these unit names is in Table 12-4.

Figure 12-2 Map of unit additions (less than 20 MW): January 1, 2011 through December 31, 2022

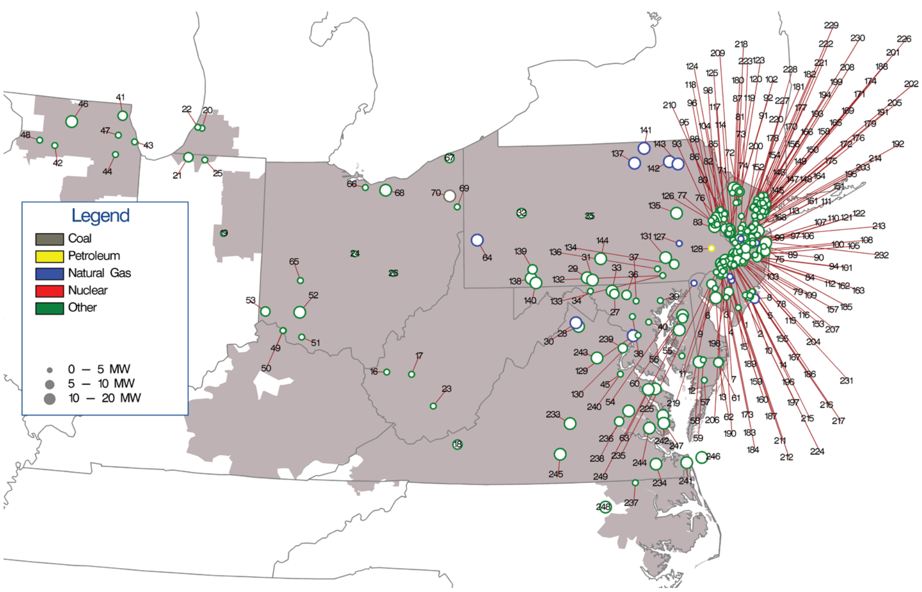


Table 12-4 Unit identification for map of unit additions (less than 20 MW): January 1, 2011 through December 31, 2022

ID	Unit	ID	Unit	ID	Unit	ID	Unit	ID	Unit
1	ACE CAPE MAY COUNTY 1 LF	56	DPL CHURCH HILL 1 SP	111	JC NORTH PARK 2 SP	166	PS E RUTHERFORD SOLAR 1 SP	221	PS SADDLE BROOK SOLAR 1 SP
2	ACE CATES ROAD 2 SP	57	DPL COSTEN 1 SP	112	JC NORTH RUN 11 SP	167	PS EASTAMPTON 1 SP	222	PS SPRINGFIELD SOLAR 1 SP
3	ACE CEDAR BRANCH 1 SP	58	DPL HEBRON 1 SP	113	JC OLD BRIDGE 1 SP	168	PS EDISON 1 SP	223	PS SUNNYMEADE SOLAR 1 SP
4	ACE EGG HARBOR-KELLOGG 1 FC	59	DPL KUMQUAT 1 SP	114	JC PAUCH 3 SP	169	PS ESSEX 105 CT	224	PS TAYLORS LANE 1 SP
5	ACE GALLOWAY LANDFILL 2 SP	60	DPL PONDTOWN 1 SP	115	JC PEMBERTON 1 SP	170	PS FAIRLAWN SOLAR 1 SP	225	PS THOROFARE SOLAR 2 SP
6	ACE GEMS LANDFILL 1 SP	61	DPL WORCESTER NORTH 1 SP	116	JC PEMBERTON 2 SP	171	PS FOODBANK 1 SP	226	PS TURNPIKE 1 SP
7	ACE MAYS LANDING 1 SP	62	DPL WORCESTER SOUTH 2 SP	117	JC QUAKERTOWN 9 SP	172	PS FORTY NINTH SOLAR 1 SP	227	PS W CALDWELL SOLAR 1 SP
8	ACE MIDTOWN THERMAL 2 CT	63	DPL WYE MILLS 1 SP	118	JC RICHLINE 3 SP	173	PS GLOUCESTER SOLAR 1 SP	228	PS W CALDWELL SOLAR 2 SP
9	ACE OAK FAIRTON 1 SP	64	DUQ PIT MICROGRID 1 CT	119	JC RINGOES 1 SP	174	PS HACKENSACK 1 SP	229	PS WALDWICK SOLAR 1 SP
10	ACE PEAR STREET 1 SP	65	FE DOVETAIL 1 CT	120	JC SUSSEX 1 LF	175	PS HIGHLAND PARK 3 BT	230	PS WEST ORANGE SOLAR 1 SP
11	ACE PILESGROVE 1 SP	66	FE ERIE COUNTY 1 LF	121	JC TINTON FALLS 3 SP	176	PS HIGHLAND PARK 4 SP	231	PS WEST PEMBERTON 1 SP
12	ACE PILESGROVE 2 SP	67	FE GENEVA 1 LF	122	JC UPPER FREEHOLD 1 SP	177	PS HILLSDALE SOLAR 1 SP	232	PS WEST WINDSOR 1 CT
13	ACE PITTSGROVE 1 SP	68	FE LORAIN 1 LF	123	JC WANTAGE 2 SP	178	PS HINCHMANS SOLAR 1 SP	233	VP BUCKINGHAM 1 SP
14	ACE SEASHORE 1 SP	69	FE MAHONING 1 LF	124	JC WARREN 1 SP	179	PS HOBOKEN SOLAR 2 SP	234	VP GARDNER FARMS 1 SP
15	ACE TANSBORO ROAD 1 FC	70	FE WARREN-EVERGREEN 1 CT	125	JC WASHBURN AVE 4 SP	180	PS HOPEWELL 1 SP	235	VP GARDYS MILL ROAD 5 SP
16	AEP BALLS GAP 1 BT	71	JC AUGUSTA 1 SP	126	ME GLENDON 1 LF	181	PS HOPEWELL 2 BT	236	VP HOLLYFIELD 1 SP
17	AEP CHARLESTON 1 LF	72	JC BEAVER RUN 3 SP	127	ME READING HOSPITAL 1 CT	182	PS JACKSON SOLAR 1 SP	237	VP MURPHY 1 SP
18	AEP CLOYDS MT 1 LF	73	JC BERKSHIRE 2 SP	128	PE MORRIS ROAD 1 D	183	PS KINSLEY BEAVER 2 SP	238	VP NORTHEAST 2 LF
19	AEP DEERCREEK 1 SP	74	JC BERNARDS TOWNSHIP 1 SP	129	PEP CAPITAL POWER PLANT 1 CT	184	PS KINSLEY DEPTFORD 1 SP	239	VP OCCOQUAN 1 LF
20	AEP EAST WATERVLIET 1 SP	75	JC BRICKYARD 4 SP	130	PEP ROLLINS AVENUE 3 SP	185	PS KUSER SOLAR 1 SP	240	VP OCCOQUAN 2 LF
21	AEP OLIVE 1 SP	76	JC COPPER HILL 4 SP	131	PL DART CONTAINER 1-2 LF	186	PS LANDFILL 5 SP	241	VP OCEANA 1 SP
22	AEP ORCHARD HILLS 1 LF	77	JC CYPHERS ROAD 5 SP	132	PL HOLTWOOD 11	187	PS LAWNSIDE 14 BT	242	VP PULLER 1 SP
23	AEP RALEIGH COUNTY 1 LF	78	JC DIXSOLAR 51 SP	133	PL HOLTWOOD 13	188	PS LEONIA SOLAR 1 SP	243	VP REMINGTON 1 SP
24	AEP TRENT 1 BT	79	JC DIXSOLAR 52 SP	134	PL KEYSTONE 1 SP	189	PS LUMBERTON STACY HAINES 5 SP	244	VP ROCHAMBEAU 1 SP
25	AEP TWINBRANCH 1 SP	80	JC DOMIN LANE 1 SP	135	PL PA SOLAR 1 SP	190	PS MANTUA CREEK 7 BT	245	VP TWITTYS CREEK 1 SP
26	AEP ZANESVILLE 2 LF	81	JC DURBAN AVENUE 1 SP	136	PL TURKEY HILL 1 WF	191	PS MARION SOLAR 1 SP	246	VP VIRGINIA OFFSHORE 1 WF
27	AP BAKER POINT 1 SP	82	JC E FLEMINGTON 5 SP	137	PN ALPACA GLORY BARN 1 D	192	PS MATRIX PA SOLAR 2 SP	247	VP WAN - GLOUCESTER 1 SP
28	AP DOUBLE TOLLGATE SP	83	JC EAST AMWELL 7 SP	138	PN GARRETT 1 BT	193	PS MAYWOOD SOLAR 1 SP	248	VP WHITAKERS 1 SP
29	AP ELK HILL 1 SP	84	JC EGYPT 3 SP	139	PN LAUREL HIGHLANDS 2 LF	194	PS METRO HQ 2 SP	249	VP WOODBINE ROAD 1 SP
30	AP HP HOOD 1 CT	85	JC FISCHER 8 SP	140	PN MEYERSDALE 2 BT	195	PS MIDDLESEX 1 SP		
31	AP LETZBURG - ELK HILL 2 SP	86	JC FOUL RIFT ROAD 1 SP	141	PN MILAN ENERGY 1 D	196	PS MILL CREEK 1 SP		
32	AP MAHONING CREEK 1 H	87	JC FRANKFORD 4 SP	142	PN NORTH MESHOPPEN 1 CT	197	PS MOORESTOWN 1 SP		
33	AP MT ST MARYS PV PARK 2 SP	88	JC FRANKLIN 7 SP	143	PN OXBOW CREEK ENERGY CENTER 1 D	198	PS MT LAUREL 1 SP		
34	AP PINESBURG 1 SP	89	JC FREEMALL 1 FC	144	PN WHITETAIL 1 SP	199	PS NEW MILFORD SOLAR 1 SP		
35	AP STATE COLLEGE 1 BT	90	JC FRENCHES 2 SP	145	PS ALDENE SOLAR 1 SP	200	PS NEW ROAD 1 SP		
36	AP UNION BRIDGE 1 SP	91	JC FRENCHTOWN 1 SP	146	PS ATHENIA SOLAR 1 SP	201	PS NEWARK SOLAR 1 SP		
37	BC ALPHA RIDGE 1 LF	92	JC FRENCHTOWN 2 SP	147	PS BAYONNE 1 SP	202	PS NEWARK SOLAR 3 SP		
38	BC BRIGHTON DAM 1 H	93	JC FRENCHTOWN 3 SP	148	PS BAYONNE SOLAR 2 SP	203	PS NIXON LANE 2 SP		
39	BC KINGSVILLE 1 SP	94	JC HANOVER 2 SP	149	PS BELLEVILLE SOLAR 1 SP	204	PS NORTH AMERICAN 4 SP		
40	BC MILLERSVILLE 1 LF	95	JC HARMONY 1 SP	150	PS BENNETTS SOLAR 1 SP	205	PS NORTH AVE SOLAR 1 SP		
41	COM COUNTRYSIDE 1 LF	96	JC HIGH STREET 6 SP	151	PS BLACK ROCK 1 SP	206	PS OWENS CORNING 1 SP		
42	COM DIXON LEE 5 LF	97	JC HOFFMAN STATION ROAD 2 SP	152	PS BRIDGEWATER SOLAR 2 SP	207	PS PARKLANDS 1 SP		
43	COM GRAND RIDGE 6 BT	98	JC HOLLAND 4 SP	153	PS BUSTLETON 2 SP	208	PS PATERSON PLANK ROAD 1 SP		
44	COM MAGID GLOVE 1 BT	99	JC HOLMDEL 9 SP	154	PS CALDWELL PUMP 2 BT	209	PS PENNINGTON 3 BT		
45	COM MORRIS 1 LF	100	JC HOWELL 1 SP	155	PS CAMPUS DRIVE 2 SP	210	PS PENNINGTON 4 SP		
46	COM ORCHARD 1 LF	101	JC JACOBSTOWN 1 SP	156	PS CEDAR GROVE SOLAR 1 SP	211	PS PENNSAUKEN 1 LF		
47	COM SOLBERG 1 BT	102	JC JUNCTION ROAD 6 SP	157	PS CEDAR LANE FLORENCE 6 SP	212	PS PENNSAUKEN 3 SP		
48	COM STERLING RAIL 1 BT	103	JC LAKEHURST 3 SP	158	PS COOK ROAD SOLAR 2 SP	213	PS PRINCETON HOSPITAL 1 CT		
49	DEOK BECKJORD 1 BT	104	JC LEBANON 1 SP	159	PS COOPER HOSPITAL 1 BT	214	PS RARITAN CENTER 3 SP		
50	DEOK BECKJORD 2 BT	105	JC LEGLER LANDFILL 7 SP	160	PS COOPER HOSPITAL 15 SP	215	PS REEVES EAST 3 SP		
51	DEOK BROWN COUNTY 1 LF	106	JC MANALAPAN 1 SP	161	PS CRANBURY 2 SP	216	PS REEVES SOUTH 1 SP		
52	DEOK CLINTON 1 BT	107	JC MILLHURST 3 SP	162	PS CROSSWIC 1 SP	217	PS REEVES WEST 4 SP		
53	DEOK WILLEY 1 BT	108	JC MUDDY FORGE 3 SP	163	PS CROSSWIC 2 SP	218	PS RIDER UNIVERSITY 3 SP		
54	DPL BLOOM ENERGY 1 FC	109	JC NORTH HANOVER 4 SP	164	PS DEVILSBROOK 1 SP	219	PS RIVER ROAD 2 SP		
55	DPL BUCKTOWN 1 SP	110	JC NORTH PARK 1 SP	165	PS DOREMUS SOLAR 1 SP	220	PS ROSELAND SOLAR 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, 2022. 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, 2022

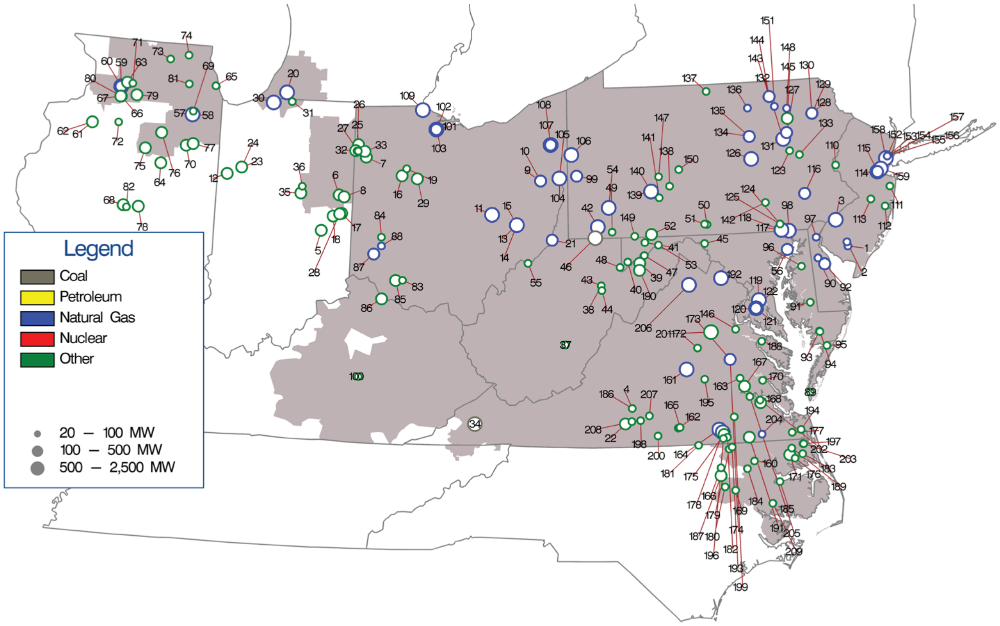


Table 12-5 Unit identification for map of unit additions (20 MW or greater): January 1, 2011 through December 31, 2022

ID	Unit	ID	Unit	ID	Unit	ID	Unit
1	ACE CLAYVILLE 1 CT	56	BC PERRYMAN 6 CT	111	JC HAMILTON ROAD 5 SP	166	VP CHESTNUT 1 SP
2	ACE VINELAND 11 CT	57	COM 929 JACKSON 1 CC	112	JC OAK RIDGE 3 SP	167	VP CHICKAHOMINY 1 SP
3	ACE WEST DEPTFORD CROWN POINT 1 CC	58	COM 929 JACKSON 2 CC	113	JC PLUMSTED ENERGY 6 BT	168	VP COLONIAL TRAIL WEST 1 SP
4	AEP ALTAVISTA 1 SP	59	COM 942 NELSON 1 CC	114	JC WOODBRIDGE 1 CC	169	VP CONETOE 2 SP
5	AEP BELLFLOWER 1 SP	60	COM 942 NELSON 2 CC	115	JC WOODBRIDGE 2 CC	170	VP CORRECTIONAL 1 SP
6	AEP BITTER RIDGE 1 WF	61	COM BISHOP HILL 1 WF	116	ME BIRDSBORO 1 CC	171	VP DESERT 1 WF
7	AEP BLUE CREEK 3 WF	62	COM BISHOP HILL 2 WF	117	PE DELTA 1-4 CC	172	VP DESPER 1 SP
8	AEP BLUFF POINT 2 WF	63	COM BLOOMING GROVE 1 WF1	118	PE DELTA 5-7 CC	173	VP DOSWELL 2 CT
9	AEP CARROLL COUNTY 1 CC	64	COM BRIGHT STALK 1 WF	119	PEP KEYS ENERGY CENTER 1 CC	174	VP DOSWELL 3 CT
10	AEP CARROLL COUNTY 2 CC	65	COM GRAND RIDGE 7 BT	120	PEP ST CHARLES - KELSON RIDGE 1 CC	175	VP DRY BREAD 1 SP
11	AEP DRESDEN 1 CC	66	COM GREEN RIVER 1 WF	121	PEP ST CHARLES-KELSON RIDGE 1 CC	176	VP ELIZABETH CITY 1 SP
12	AEP FOWLER RIDGE 4 WF	67	COM GREEN RIVER 2 WF	122	PEP ST CHARLES-KELSON RIDGE 2 CC	177	VP GRASSFIELD 1 SP
13	AEP GUERNSEY 11 CC	68	COM HILLTOPPER 1 WF	123	PL HAZEL 1 FW	178	VP GREENSVILLE 1 CC
14	AEP GUERNSEY 21 CC	69	COM JOLIET 1 BT	124	PL HOLTWOOD 18	179	VP GUTENBERG - OCONECHE 1 SP
15	AEP GUERNSEY 31 CC	70	COM KELLY CREEK 1 WF	125	PL HOLTWOOD 19	180	VP HARTS MILL 1 SP
16	AEP HARDIN 2 SP	71	COM LEE DEKALB 3 BT	126	PL HUMMEL STATION 1 CC	181	VP HAWTREE CREEK 1 SP
17	AEP HEADWATERS 1 WF	72	COM LONE TREE 3 WF	127	PL HUNLOCK CC	182	VP IVORY LANE 1 SP
18	AEP HEADWATERS 2 WF	73	COM MARENGO 1 BT	128	PL LACKAWANNA COUNTY 1 CC	183	VP IVY NECK 2 SP
19	AEP HOG CREEK 1 WF	74	COM MCHENRY 1 BT	129	PL LACKAWANNA COUNTY 2 CC	184	VP KELFORD 1 SP
20	AEP INDECK NILES ENERGY CENTER 1 CC	75	COM MINONK 1 WF	130	PL LACKAWANNA COUNTY 3 CC	185	VP MACKEYS 1 SP
21	AEP LONG RIDGE ENERGY 1 CC	76	COM OTTER CREEK 1 WF	131	PL MOXIE FREEDOM 11 CC	186	VP MECHANICSVILLE 2 SP
22	AEP MAPLEWOOD 1 SP	77	COM PILOT HILL 1 WF	132	PL MOXIE FREEDOM 21 CC	187	VP MOCCASIN CREEK - FERN 1 SP
23	AEP MEADOW LAKE 5 WF	78	COM RADFORDS RUN 1 WF	133	PL PA SOLAR 2 SP	188	VP MONTROSS 1 SP
24	AEP MEADOW LAKE 6 WF	79	COM SHADY OAKS 1 WF	134	PL PATRIOT 1 F	189	VP MORGAN CORNER 1 SP
25	AEP PAULDING 3 WF	80	COM WALNUT RIDGE 1 WF	135	PL PATRIOT 2 F	190	VP NEW CREEK 1 WF
26	AEP PAULDING 41 WF	81	COM WEST CHICAGO 3 BT	136	PN BEAVER DAM 1 D	191	VP NEWSOMS 1 SP
27	AEP PAULDING 42 WF	82	COM WHITNEY HILL 2 WF	137	PN BIG LEVEL 1 WF	192	VP PANDA STONEWALL 1 CC
28	AEP RIVERSTART 1 SP	83	DAY HIGHLAND COUNTY 1 SP	138	PN CHESTNUT FLATS 1 WF	193	VP PECAN 1 SP
29	AEP SCIOTO RIDGE 1 WF	84	DAY TAIT 8 BT	139	PN FAIRVIEW 1 CC	194	VP POCATY 1 SP
30	AEP ST JOSEPH ENERGY CENTER 1 CC	85	DEOK HILLCREST 1 SP	140	PN FAIRVIEW 2 CC	195	VP POWHATAN 2 SP
31	AEP ST JOSEPH SOLAR PARK 1 SP	86	DEOK MELDAHL DAM 1 H	141	PN HIGHLAND NORTH 2 WF	196	VP PUMPKINSEED 1 SP
32	AEP TIMBER2 1 WF	87	DEOK MIDDLETOWN ENERGY 1 CC	142	PN LAUREL HILLS 1 WF	197	VP RANCHLAND 2 SP
33	AEP TRISHE 1 WF	88	DEOK YANKEE 1 F	143	PN LIBERTY ASYLUM 10 F	198	VP RENAN 1 SP
34	AEP VIRGINIA CITY 1 F	89	DPL CHERRYDALE 1 SP	144	PN LIBERTY ASYLUM 20 F	199	VP SAPONY 1 SP
35	AEP WILDCAT 1A WF	90	DPL DEMEC - CLAYTON 2 CT	145	PN MEHOOPANY 1 WF	200	VP SOUTH BOSTON 1 F
36	AEP WILDCAT 1B WF	91	DPL DORCHESTER COUNTY 1 SP	146	PN MEHOOPANY 2 WF	201	VP SPOTSYLVANIA 1 SP
37	AP BEECH RIDGE 2 WF	92	DPL GARRISON EC 1 CC	147	PN PATTON 1 WF	202	VP SPRING GROVE 1 SP
38	AP BEECH RIDGE 3 BT	93	DPL GREAT BAY KINGS CREEK 1 SP	148	PN PGCOGEN 2 CT	203	VP SUMMIT FARMS 1 SP
39	AP BLACK ROCK 1 WF	94	DPL GREAT BAY KINGS CREEK 2 SP	149	PN RINGER HILL 1 WF	204	VP UNION CAMP 9-10 F
40	AP FAIR WIND 2 WF	95	DPL OAK HALL 1 SP	150	PN SANDY RIDGE 1 WF	205	VP WARDS CREEK 1 SP
41	AP FOURMILE RIDGE 1 WF	96	DPL PONDTOWN 2 SP	151	PN SUGAR RUN 2 CT	206	VP WARREN COUNTY FRONT ROYAL CC
42	AP GREENE COUNTY 1 CC	97	DPL RED LION 1 FC	152	PS KEARNY 131 CT	207	VP WATER STRIDER 1 SP
43	AP LAUREL MOUNTAIN 1 BT	98	DPL WILDCAT POINT 1 CC	153	PS KEARNY 132 CT	208	VP WHITEHORN 1 SP
44	AP LAUREL MOUNTAIN 1 WF	99	DUQ MONACA-PENNCHEM 1 CC	154	PS KEARNY 133 CT	209	VP WILKINSON ENERGY CENTER 1 SP
45	AP MARLOWE 1 SP	100	EKPC TURKEY CREEK 1 SP	155	PS KEARNY 134 CT		
46	AP NORTH LONGVIEW 1 F	101	FE FREMONT 1 SCCT	156	PS KEARNY 141 CT		
47	AP PINNACLE 1 WF	102	FE FREMONT 2 SCCT	157	PS KEARNY 142 CT		
48	AP ROTH ROCK 1 WF	103	FE FREMONT ENERGY CENTER 3 CC	158	PS NEWARK ENERGY CENTER 10 CC		
49	AP SOUTH CHESTNUT 1 WF	104	FE HIBBETS MILLS ROAD 1 CC	159	PS SEWAREN 7 CC		
50	AP ST THOMAS 1 SP	105	FE HIBBETS MILLS ROAD 2 CC	160	VP AULANDER HOLLOMAN 1 SP		
51	AP ST THOMAS 2 SP	106	FE HICKORY RUN 1 CC	161	VP BEAR GARDEN		
52	AP TWIN RIDGES 1 WF	107	FE LORDSTOWN ENERGY CENTER 1 CC	162	VP BLUESTONE FARM 1 SP		
53	AP WARRIOR RUN 2 BT	108	FE LORDSTOWN ENERGY CENTER 2 CC	163	VP BRIEL FARM 1 SP		
54	AP WESTMORELAND 1 CC	109	FE OREGON ENERGY CENTER 1 CC	164	VP BRUNSWICK 1CC		
55	AP WILLOW ISLAND 1 H	110	JC EDGE ROAD 5 BT	165	VP BUTCHER CREEK 1 SP		

Generation Retirements[20] [21]

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.[22] 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.[23]

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

20 See PJM. Planning. "Generator Deactivations," (Accessed on December 31, 2022) <http://www.pjm.com/planning/services-requests/gen-deactivations.aspx>.
21 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.
22 See OATT Part V and Attachment M–Appendix § IV.
23 See PJM. "*Explaining Power Plant Retirements in PJM*," at <http://learn.pjm.com/three-priorities/planning-for-the-future/explaining-power-plant-retirements.aspx>.

persist for one year if unused, and they can be further extended, at no cost, if assigned to a new project in the interconnection queue at the same point of interconnection.[24] 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.

A new dimension to the CIR issue has emerged as a result of the fact that intermittent and storage resources do not have a must offer obligation in the capacity market like the must offer requirement for the majority of capacity resources. In the absence of a uniform must offer requirement in the capacity market, those intermittent resources that hold CIRs but do not offer in the capacity market are effectively blocking entry of competitors who would offer in the capacity market.

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.[25] 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.[26]

Generation Retirements 2011 through 2026

Table 12-6 shows that as of December 31, 2022, there are 53,187.8 MW of generation that have been, or are planned to be, retired between 2011 and 2026, of which 40,623.8 MW (76.4 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 2026

	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	3,166.5	1,016.0	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	4,110.5	100.3	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	15.9	0.0	0.0	0.0	1,020.4	102.0	0.0	50.0	0.0	0.0	1,310.3
Retirements 2022	41.0	240.5	99.0	360.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	38.5	0.0	0.0	0.0	5,385.0	0.0	0.0	0.0	0.0	0.0	6,164.3
Planned Retirements (January 1, 2023 and later)	0.0	0.0	132.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	34.0	19.2	0.0	0.0	0.0	4,184.0	1,326.0	0.0	0.0	0.0	0.0	5,695.8
Total	86.0	783.5	2,515.9	2,185.2	22.0	0.0	0.5	0.0	1,419.5	0.0	78.1	138.1	0.0	0.0	0.0	40,623.8	3,414.8	1,658.0	252.0	10.4	0.0	53,187.8

24 See OATT § 230.3.3.
25 See PJM Interconnection, L.L.C., Docket No. ER12-1177 (Feb. 29, 2012).
26 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 shows the capacity, average size, and average age of units retiring in PJM, from 2011 through 2026, while Table 12-8 shows these retirements by state. Of the 53,187.8 MW of units that has been, or are planned to be, retired between 2011 and 2026, 40,623.8 MW (76.4 percent) are coal fired steam units. These coal fired steam units have an average age of 52.3 years and an average size of 218.4 MW. Over half of the retiring coal fired steam units, 53.9 percent, are located in Ohio or Pennsylvania.

Table 12-7 Retirements by unit type: 2011 through 2026

Unit Type	Number of Units	Avg. Size (MW)	Avg. Age at Retirement (Years)	Total MW	Percent
Battery	7	12.3	5.9	86.0	0.2%
Combined Cycle	6	130.6	29.1	783.5	1.5%
Combustion Turbine	136	25.3	35.7	4,723.1	8.9%
Natural Gas	65	38.7	41.4	2,515.9	4.7%
Oil	65	33.6	46.5	2,185.2	4.1%
Other	6	3.7	19.2	22.0	0.0%
Fuel Cell	0	0.0	0.0	0.0	0.0%
Hydro	1	0.5	113.8	0.5	0.0%
Pumped Storage	1	0.5	113.8	0.5	0.0%
Run of River	0	0.0	0.0	0.0	0.0%
Nuclear	2	709.8	47.2	1,419.5	2.7%
RICE	41	5.3	26.1	216.2	0.4%
Natural Gas	0	0.0	0.0	0.0	0.0%
Oil	15	5.2	40.4	78.1	0.1%
Other	26	5.3	11.8	138.1	0.3%
Solar	0	0	0	0	0.0%
Solar + Storage	0	0	0	0	0.0%
Solar + Wind	0	0	0	0	0.0%
Steam	223	168.7	44.9	45,948.6	86.4%
Coal	186	218.4	52.3	40,623.8	76.4%
Natural Gas	23	148.5	58.0	3,414.8	6.4%
Oil	6	276.3	45.6	1,658.0	3.1%
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	417	127.5	44.9	53,187.8	100.0%

Table 12-8 Retirements (MW) by unit type and state: 2011 through 2026

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	41.0	0.0	296.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	35.7	0.0	0.0	0.0	2,818.1	1,326.0	0.0	0.0	0.0	0.0	4,516.8
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	154.0	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	3,745.3
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	1,671.0	1,066.2	6.4	0.0	0.5	0.0	614.5	0.0	8.0	24.4	0.0	0.0	0.0	2,001.9	932.5	148.0	10.0	0.0	0.0	6,948.9
OH	42.0	0.0	0.0	307.0	0.0	0.0	0.0	0.0	0.0	0.0	32.3	45.9	0.0	0.0	0.0	16,607.4	0.0	0.0	0.0	0.0	0.0	17,034.6
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	5,296.0	286.3	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	3,897.9	563.0	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	3,969.0	0.0	0.0	0.0	0.0	0.0	3,971.0
Total	86.0	783.5	2,515.9	2,185.2	22.0	0.0	0.5	0.0	1,419.5	0.0	78.1	138.1	0.0	0.0	0.0	40,623.8	3,414.8	1,658.0	252.0	10.4	0.0	53,187.8

Figure 12-4 is a map of unit retirements between 2011 and 2026, with a mapping to unit names in Table 12-9.

Figure 12-4 Map of unit retirements: 2011 through 2026

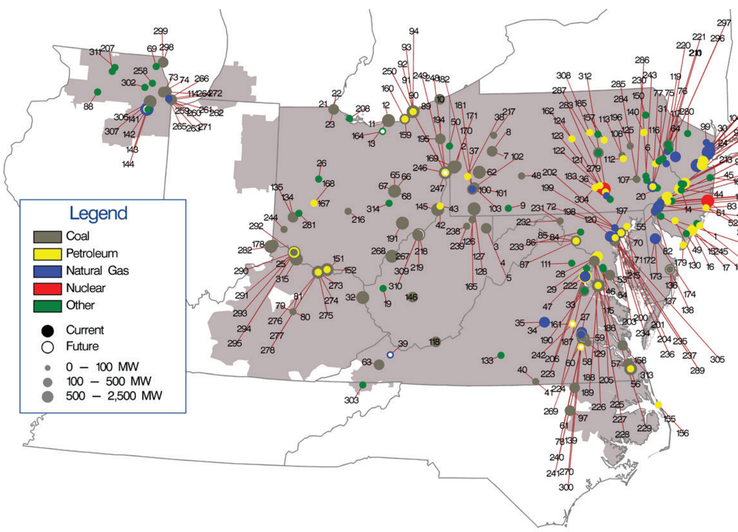


Table 12-9 Unit identification for map of unit retirements: 2011 through 2026

ID	Unit	ID	Unit	ID	Unit	ID	Unit	ID	Unit	ID	Unit
1	AC Landfill Units 1 and 2	61	Chesterfield 6	121	Harrisburg 4 CT	181	Mitchell 2	241	Roanoke Valley 2	301	Werner 1-4
2	AES Beaver Valley	62	Cheswick 1	122	Harrisburg CT 1	182	Mitchell 3	242	Rockville CT	302	West Chicago Energy Storage
3	Albright 1	63	Clinch River 3	123	Harrisburg CT 2	183	Modern Power Landfill NUG	243	Rolling Hills Landfill Generator	303	West Kingsport LF
4	Albright 2	64	Columbia Dam Hydro	124	Harrisburg CT 3	184	Monmouth NUG landfill	244	SMART Paper	304	West Shore CT 1-2
5	Albright 3	65	Conesville 3	125	Harwood 1-2	185	Montour ATG	245	Salem County LF	305	Westport 5
6	Allentown CT 1-4	66	Conesville 4	126	Hatfield's Ferry 1	186	Morgantown CT1	246	Sammis 1-4	306	Will County 3
7	Armstrong 1	67	Conesville 5	127	Hatfield's Ferry 2	187	Morgantown CT2	247	Sammis Diesel Units	307	Will County 4
8	Armstrong 2	68	Conesville 6	128	Hatfield's Ferry 3	188	Morgantown Unit 1	248	Sammis Unit 5	308	Williamsport-Lycoming CT 1-2
9	Arnold (Green Mtn. Wind Farm	69	Countryside Landfill	129	Hopewell James River Cogeneration	189	Morgantown Unit 2	249	Sammis Unit 6	309	Willow Island 1
10	Ashtabula 5	70	Crane 1	130	Howard Down 10	190	Morris Landfill Generator	250	Sammis Unit 7	310	Willow Island 2
11	Avon Lake 10	71	Crane 2	131	Hudson 1	191	Muskingum River 1-5	251	Schuylkill 1	311	Winnebago Landfill
12	Avon Lake 7	72	Crane GT1	132	Hudson 2	192	National Park 1	252	Schuylkill Diesel	312	York Generation Facility
13	Avon Lake 9	73	Crawford 7	133	Hurt NUG	193	New Bay Cogen CC	253	Sewaren 1	313	Yorktown 1-2
14	BC Landfill	74	Crawford 8	134	Hutchings 1-3, 5-6	194	Niles 1	254	Sewaren 2	314	Zanesville Landfill
15	BL England 1	75	Cromby 1	135	Hutchings 4	195	Niles 2	255	Sewaren 3	315	Zimmer 1
16	BL England 2	76	Cromby 2	136	Indian River 1	196	Northeastern Power NEPCO	256	Sewaren 4		
17	BL England 3	77	Cromby D	137	Indian River 3	197	Notch Cliff GT1	257	Sewaren 6		
18	BL England Diesel Units 1-4	78	DINWIDDIE 1 CT	138	Indian River 4	198	Notch Cliff GT2	258	Solberg 1 BT		
19	Balls Gap Battery Facility	79	Dale 1-2	139	Ingenco Petersburg	199	Notch Cliff GT3	259	Southeast Chicago CT11		
20	Barbados AES Battery	80	Dale 3	140	Jenkins CT 1-2	200	Notch Cliff GT4	260	Southeast Chicago CT12		
21	Bay Shore 2	81	Dale 4	141	Joliet 6	201	Notch Cliff GT5	261	Southeast Chicago CT5		
22	Bay Shore 3	82	Deepwater 1	142	Joliet 7	202	Notch Cliff GT6	262	Southeast Chicago CT6		
23	Bay Shore 4	83	Deepwater 6	143	Joliet 8	203	Notch Cliff GT7	263	Southeast Chicago CT7		
24	Bayonne Cogen Plant (CC)	84	Dickerson CT1	144	Joliet Energy Storage	204	Notch Cliff GT8	264	Southeast Chicago CT8		
25	Beckjord Battery Unit 2	85	Dickerson Unit 1	145	Kammer 1-3	205	Oaks Landfill	265	Southeast Chicago GT10		
26	Bellefontaine Landfill Generating Station	86	Dickerson Unit 2	146	Kanawha River 1-2	206	Occoquan 1 LF	266	Southeast Chicago GT9		
27	Bellemeade	87	Dickerson Unit 3	147	Kearny 10	207	Orchard Hills LF	267	Sporn 1-4		
28	Benning 15	88	Dixon Lee Landfill Generator	148	Kearny 11	208	Ottawa County Project	268	Sporn 5		
29	Benning 16	89	Eastlake 1	149	Kearny 9	209	Oyster Creek	269	Spruance NUG1 (Rich 1-2)		
30	Bergen 3	90	Eastlake 2	150	Keystone Recovery (Units 1 - 7)	210	PL MARTINS CREEK 1-4 CT	270	Spruance NUG2 (Rich 3-4)		
31	Bethlehem Renewable Energy Generator (Landfill)	91	Eastlake 3	151	Killen 2	211	PL MARTINS CREEK 1-4 CT	271	State Line 3		
32	Big Sandy 2	92	Eastlake 4	152	Killen CT	212	Pedricktown Cogen CC	272	State Line 4		
33	Birchwood Plant	93	Eastlake 5	153	Kimberly Clark Generator	213	Pennsbury Generator Landfill 1	273	Stuart 1		
34	Bremo 3	94	Eastlake 6	154	Kinsley Landfill	214	Pennsbury Generator Landfill 2	274	Stuart 2		
35	Bremo 4	95	Eddystone 1	155	Kitty Hawk GT 1	215	Perryman 2	275	Stuart 3		
36	Brunner Island Diesels	96	Eddystone 2	156	Kitty Hawk GT 2	216	Picway 5	276	Stuart 4		
37	Brunot Island 1B	97	Edgecomb NUG (Rocky 1-2)	157	Koppers Co. IPP	217	Piney Creek NUG	277	Stuart Diesels 1-4		
38	Brunot Island 1C	98	Edison 1-3	158	Lake Kingman	218	Pleasant Unit 1	278	Stuart Diesels 1-4		
39	Buchanan 1-2	99	Elmwood Park Power	159	Lake Shore 18	219	Pleasant Unit2	279	Sunbury 1-4		
40	Buggs Island 1 (Mecklenberg)	100	Elrama 1	160	Lake Shore EMD	220	Portland 1	280	Sussex County LF		
41	Buggs Island 2 (Mecklenberg)	101	Elrama 2	161	Lanier 1 CT	221	Portland 2	281	Tait Battery		
42	Burger 3	102	Elrama 3	162	Lock Haven CT 1	222	Possum Point 3	282	Tanners Creek 1-4		
43	Burger EMD	103	Elrama 4	163	Logan	223	Possum Point 4	283	Three Mile Island Unit 1		
44	Burlington 8,11	104	Essex 10-11	164	Lorain 1 LF	224	Possum Point 5	284	Titus 1		
45	Burlington 9	105	Essex 12	165	MEA NUG (WVU)	225	Potomac River 1	285	Titus 2		
46	Buzzard Point East Banks 1,2,4-8	106	Essex 9	166	MH50 Markus Hook Co-gen	226	Potomac River 2	286	Titus 3		
47	Buzzard Point West Banks 1-9	107	Evergreen Power United Corstack	167	Mad River CTs A	227	Potomac River 3	287	Viking Energy NUG		
48	Cambria CoGen	108	FRACKVILLE WHEELABRATOR 1	168	Mad River CTs B	228	Potomac River 4	288	Vineland West CT		
49	Cape May County Municipal LF	109	Fairless Hills Landfill A	169	Mansfield 1	229	Potomac River 5	289	Wagner 2		
50	Carbon Limestone LF	110	Fairless Hills Landfill B	170	Mansfield 2	230	Pottstown LF (Moser)	290	Walter C Beckjord 1		
51	Cedar 1	111	Fauquier County Landfill	171	Mansfield 3	231	R Paul Smith 3	291	Walter C Beckjord 2		
52	Cedar 2	112	Fishbach CT 1	172	McKee 1	232	R Paul Smith 4	292	Walter C Beckjord 3		
53	Chalk Point Unit 1	113	Fishbach CT 2	173	McKee 2	233	Reichs Ford Road Landfill Generator	293	Walter C Beckjord 4		
54	Chalk Point Unit 2	114	Fisk Street 19	174	McKee 3	234	Riverside 4	294	Walter C Beckjord 5-6		
55	Chambers CCLP	115	GUDE Landfill	175	Mercer 1	235	Riverside 6	295	Walter C Beckjord GT 1-4		
56	Chesapeake 1-4	116	Gilbert 1-4	176	Mercer 2	236	Riverside 7	296	Warren County Landfill		
57	Chesapeake 7-10	117	Glen Gardner 1-8	177	Mercer 3	237	Riverside 8	297	Warren County NUG		
58	Chesterfield 3	118	Glen Lyn 5-6	178	Miami Fort 6	238	Riversville 5	298	Waukegan 7		
59	Chesterfield 4	119	Glendon LF	179	Middle 1-3	239	Riversville 6	299	Waukegan 8		
60	Chesterfield 5	120	Gould Street Generation Station	180	Missouri Ave B,C,D	240	Roanoke Valley 1	300	Weakley CT		

Current Year Generation Retirements

Table 12-10 shows that in 2022, 6,164.3 MW of generation retired. The largest generator that retired in 2022 was the 638.0 MW Avon Lake Unit 9 coal fired steam unit located in the ATSI Zone. Of the 6,164.3 MW of generation that retired, 1,300.0 MW (21.1 percent) were located in the DUKE Zone.

Table 12-10 Unit deactivations: 2022

Company	Unit Name	ICAP (MW)	Unit Type	Zone Name	Age (Years)	Retirement Date
Cape May County Municipal Utilities Authority	Cape May County Municipal LF	1.9	RICE-Other	ACEC	8	1-Mar-2022
GenOn Energy, Inc.	Avon Lake 10	21.0	CT-Oil	ATSI	54	31-Mar-2022
GenOn Energy, Inc.	Avon Lake 9	638.0	Steam-Coal	ATSI	52	31-Mar-2022
GenOn Energy, Inc.	Cheswick 1	565.0	Steam-Coal	DUQ	52	31-Mar-2022
Hoosier Energy Rural Electric Cooperative Inc	Orchard Hills LF	15.3	RICE-Other	COMED	5	31-Mar-2022
Riverstone Holdings LLC	Fishbach CT 1	28.0	CT-Oil	PPL	53	1-Apr-2022
Riverstone Holdings LLC	Fishbach CT 2	14.0	CT-Oil	PPL	53	1-Apr-2022
Riverstone Holdings LLC	Jenkins CT 1-2	27.6	CT-Oil	PPL	53	1-Apr-2022
Riverstone Holdings LLC	Lock Haven CT 1	14.0	CT-Oil	PPL	52	1-Apr-2022
Riverstone Holdings LLC	West Shore CT 1	28.0	CT-Oil	PPL	53	1-Apr-2022
Riverstone Holdings LLC	Williamsport-Lycoming CT 1-2	26.6	CT-Oil	PPL	55	1-Apr-2022
Renewable Energy Systems Holdings LTD	Joliet Energy Storage	20.0	Battery	COMED	7	29-Apr-2022
Renewable Energy Systems Holdings LTD	West Chicago Energy Storage	20.0	Battery	COMED	7	29-Apr-2022
American Electric Power Company, Inc.	Zimmer 1	330.0	Steam-Coal	DUKE	31	31-May-2022
American Municipal Power, Inc.	Ottawa County Project	3.6	RICE-Other	ATSI	21	31-May-2022
GenOn Energy, Inc.	Morgantown Unit 1	610.0	Steam-Coal	PEPCO	52	31-May-2022
GenOn Energy, Inc.	Morgantown Unit 2	619.0	Steam-Coal	PEPCO	51	31-May-2022
NRG Energy Inc	Waukegan 7	328.0	Steam-Coal	COMED	64	31-May-2022
NRG Energy Inc	Waukegan 8	356.1	Steam-Coal	COMED	60	31-May-2022
Riverstone Holdings LLC	Harwood 1-2	28.0	CT-Oil	PPL	55	31-May-2022
Starwood Capital Group LLC	Logan	219.0	Steam-Coal	ACEC	28	31-May-2022
The AES Corporation	Zimmer 1	365.0	Steam-Coal	DUKE	31	31-May-2022
Vistra Energy Corp	Zimmer 1	605.0	Steam-Coal	DUKE	31	31-May-2022
Arclight Capital Holdings LLC	Essex 9	81.0	CT-Natural Gas	PSEG	32	1-Jun-2022
Riverstone Holdings LLC	Allentown CT 1-4	56.0	CT-Oil	PPL	55	1-Jun-2022
Riverstone Holdings LLC	Harrisburg CT 1	13.4	CT-Oil	PPL	55	1-Jun-2022
Riverstone Holdings LLC	Harrisburg CT 2	13.9	CT-Oil	PPL	55	1-Jun-2022
Riverstone Holdings LLC	Harrisburg CT 3	13.8	CT-Oil	PPL	55	1-Jun-2022
Riverstone Holdings LLC	Martins Creek CT 3	18.0	CT-Natural Gas	PPL	51	1-Jun-2022
Riverstone Holdings LLC	New Bay Cogen CC	120.2	Combined Cycle	PSEG	29	1-Jun-2022
Riverstone Holdings LLC	Pedricktown Cogen CC	120.3	Combined Cycle	ACEC	30	1-Jun-2022
Starwood Capital Group LLC	Chambers CCLP	239.9	Steam-Coal	ACEC	28	7-Jun-2022
NRG Energy Inc	Will County 4	510.0	Steam-Coal	COMED	59	30-Jun-2022
GenOn Energy, Inc.	Morgantown CT1	16.0	CT-Oil	PEPCO	52	1-Oct-2022
GenOn Energy, Inc.	Morgantown CT2	16.0	CT-Oil	PEPCO	52	1-Oct-2022
City of Vineland	Vineland West CT	26.0	CT-Oil	ACEC	54	14-Oct-2022
GenOn Energy, Inc.	Dickerson CT1	18.0	CT-Oil	PEPCO	56	23-Oct-2022
American Municipal Power, Inc.	Carbon Limestone LF	17.7	RICE-Other	ATSI	21	15-Nov-2022
Intelligent Generation LLC	Solberg 1 BT	1.0	Battery	COMED	5	12-Dec-2022
Total		6,164.3				

Planned Generation Retirements

Table 12-11 shows that, as of December 31, 2022, there are 5,695.8 MW of generation that have requested retirement after December 31, 2022. Of the 5,695.8 MW requesting retirement, 4,184.0 MW (73.5 percent) are coal fired steam units. As of December 31, 2022, there are planned coal fired unit retirements in four different PJM zones. Of the 5,695.8 MW of planned retirements, 1,522.2 MW (26.7 percent) are located in the ATSI Zone. Of the generation requesting retirement in the ATSI Zone, 1,490.0 MW (97.9 percent) are coal fired steam units.

Table 12-11 Planned retirement of units: December 31, 2022

Company	Unit Name	ICAP (MW)	Unit Type	Zone Name	Projected Deactivation Date
American Municipal Power, Inc.	Lorain 1 LF	19.2	RICE-Other	ATSI	01-Apr-23
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
Archaea Energy	DINWIDDIE 1 CT	3.0	RICE-Oil	DOM	01-Jun-23
NRG Energy Inc	Joliet 6	290.0	Steam-Natural Gas	COMED	01-Jun-23
NRG Energy Inc	Joliet 7	518.0	Steam-Natural Gas	COMED	01-Jun-23
NRG Energy Inc	Joliet 8	518.0	Steam-Natural Gas	COMED	01-Jun-23
Archaea Energy	Lanier 1 CT	7.0	RICE-Oil	DOM	01-Jun-23
Riverstone Holdings LLC	Martins Creek CT 1	18.0	CT-Natural Gas	PPL	01-Jun-23
Riverstone Holdings LLC	Martins Creek CT 2	17.3	CT-Natural Gas	PPL	01-Jun-23
Riverstone Holdings LLC	Martins Creek CT 4	17.3	CT-Natural Gas	PPL	01-Jun-23
Avenue Capital Group LLC	Pleasant Unit 1	639.0	Steam-Coal	APS	01-Jun-23
Avenue Capital Group LLC	Pleasant Unit2	639.0	Steam-Coal	APS	01-Jun-23
Archaea Energy	Rockville CT	4.0	RICE-Oil	DOM	01-Jun-23
Avenue Capital Group LLC	Sammis Diesel Units	13.0	RICE-Oil	ATSI	01-Jun-23
Avenue Capital Group LLC	Sammis Unit 5	290.0	Steam-Coal	ATSI	01-Jun-23
Avenue Capital Group LLC	Sammis Unit 6	600.0	Steam-Coal	ATSI	01-Jun-23
Avenue Capital Group LLC	Sammis Unit 7	600.0	Steam-Coal	ATSI	01-Jun-23
Archaea Energy	Weakley CT	7.0	RICE-Oil	DOM	01-Jun-23
NRG Energy Inc	Indian River 4	410.0	Steam-Coal	DPL	31-Dec-26
Total		5,695.8			

In addition to the 5,695.8 MW of announced unit retirements as of December 31, 2022, there are significantly more unit retirements expected as a result of state environmental actions. PJM anticipates an additional 20,000 MW of unit retirements between 2024 and 2030, and an additional 10,000 MW of unit retirements between 2031 and 2045.[27] [28]

Generation Queue[29]

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.[30] 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 AH2 opened on October 1, 2021 and closed on March 10, 2022, Queue AI1 opened on April 1, 2022 and closed on September 10, 2022 and Queue AI2 opened on October 1, 2022. 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.[31] 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.[32]

27 See "Generation Deliverability Test Modifications: Light Load, Summer & Winter," presented at February 23, 2022 meeting of the Planning Committee Special Session on CIR's for ELCC Resources at p8. <https://www.pjm.com/-/media/committees-groups/committees/pc/2022/20220223-special/20220223-item-04-generator-deliverability-proposal-analytical-results.ashx>.
28 See "Illinois Generation Retirement Study," (August 3, 2022). <http://www.pjm.com/-/media/library/reports-notices/special-reports/2022/2022-pjm-illinois-generation-retirement-study.ashx>.
29 The queue totals in this report are the winter net MW energy for the interconnection requests ("MW Energy") as shown in the queue.
30 See OATT Parts IV & VI.
31 See PJM Filing, Docket ER21-2203 (June 24, 2021).
32 176 FERC ¶ 61,117 (2021).

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.[33] 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.[34] 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.[35] 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.[36]

33 See PJM Filing, Docket ER21-2203 (June 24, 2021).
34 176 FERC ¶ 61,117 (2021).
35 See "PJM Manual 14C: Generation and Transmission Interconnection Process," Rev. 14 (January 27, 2021).
36 PJM does not track the duration of suspensions or PJM termination of projects.

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 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. The PJM queue evaluation process should also evaluate and address the incentives to project developers to act in ways that are not consistent with an effective and efficient queue process for the system. For example, 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 by requiring multiple restudies.

Starting in 2020, PJM has made significant progress in addressing many of the underlying issues. 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.

The proposal endorsed by the IPRTF includes modifications to implement a cluster/cycle based processing method to replace the first in/first out processing method.[37] This change will allow projects to move forward based on a first ready/first out analysis, where readiness is demonstrated through site control and financial milestones and there is an option to exit the study process early based on system impacts. The proposal also includes defining progress to completion through three phases, with a customer decision at the end of each. The proposed solution requires a stronger definition of site control, and includes readiness deposits (some of which are nonrefundable) based on the phase of development. Additional process modifications include limits to technology changes, improvements to the application review phase, removal of optional

37 See "Interconnection Process Reform," presented at April 27, 2022 meeting of the Members Committee. <https://www.pjm.com/-/media/committees-groups/committees/mc/2022/20220427/20220427-item-01a-1-interconnection-process-reform-presentation.ashx>.

interconnection study processes, modifications to the study schedules to reduce the number of restudies required in the event of project modifications, adjusting the queue window schedule to coincide with the previous clusters' milestones, and modifications to cost responsibility by assigning responsibility to all projects within a queue cycle. The proposed solution should help to reduce backlog and to remove projects that are not viable earlier to help improve the overall efficiency of the queue process. On June 14, 2022, PJM filed tariff changes to incorporate the endorsed modifications to the interconnection queue process.[38] On November 29, 2022, the Commission issued an order accepting PJM's tariff revisions.[39]

The new process includes a transition process which treats projects based on their current queue status. All projects through queue window AD2 will continue as part of the existing queue process. The transition process assigns existing queue projects in queue windows AE1 through AH1 to transition cycle 1 and transition cycle 2 and also provides for the expedited treatment (fast track) of projects submitted in the AE1 through AG1 queue windows with upgrade costs less than $5 million. Transition cycle 1 is expected to begin in late 2023. Transition cycle 2 is expected to begin in late 2024. Projects submitted in queue window AH2 and beyond will be evaluated starting in early 2026. While new applications will continue to be accepted, the transition process will delay their consideration for an unknown period. The transition process itself will not begin until projects eligible for the existing queue process have an executed ISA or the equivalent. After the process for projects in transition cycles 1 and 2 has been completed, projects in queue AH2 and possible subsequent queues will be studied. The new process will not be fully implemented until PJM provides notice that it is accepting applications for the first cycle entirely under the new process. That notice will be provided only after PJM has complete all the prior required transition steps.

On July 15, 2021, the Commission issued an Advance Notice of Proposed Rulemaking (ANOPR).[40] 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.

On June 16, 2022, the Commission issued a Notice of Proposed Rulemaking (NOPR).[41] The NOPR largely aligned with the PJM proposal that was endorsed by the IPRTF. The NOPR addresses reforms to implement a first ready/first served cluster study process, including cluster study costs and an allocation of network upgrade costs to the cluster, increased financial commitments and readiness requirements and improvements to the speed of the queue processing.

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.[42]

Interconnection Process Studies and Agreements[43]

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.

38 See *PJM*, Docket No. ER22-2110 (June 14, 2022).
39 181 FERC ¶ 61,162 (2022).
40 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).
41 See *Improvements to Generator Interconnection Procedures and Agreements*, Notice of Proposed Rulemaking, 179 FERC ¶ 61,194 (June 16, 2022).
42 Once implemented, the approved solutions from PJM's Interconnection Process Reform Task Force (IPRTF) should result in improvements in these areas.
43 See "PJM Manual 14A: New Services Request Process," Rev. 29 (August 24, 2021) for a complete explanation of the interconnection process studies and agreements.

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 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 and from federal and state subsidies and incentives. On December 31, 2022, 287,492.7 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.[44]

There were 254,998.8 MW in generation queues, in the status of active, under construction or suspended, at the end of 2021. In 2022, the AH2 window closed, the AI1 window opened and closed, and the AI2 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, 2022, there were 287,492.7 MW in generation queues, in the status of active, under construction or suspended, an increase of 32,493.9 MW (12.7 percent) from December 31, 2021. Table 12-15 shows MW in queues by expected completion year and MW changes in the queue between December 31, 2021, and December 31, 2022, for ongoing projects, i.e. projects with the status active, under construction or suspended.[45]

Table 12-15 Queue comparison by expected completion year (MW): December 31, 2021 and December 31, 2022[46]

Year	As of 12/31/2021	As of 12/31/2022	Year Change MW	Year Change 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	0.0	0.0	0.0	0.0%
2013	0.0	0.0	0.0	0.0%
2014	0.0	0.0	0.0	0.0%
2015	0.0	0.0	0.0	0.0%
2016	3.4	3.4	0.0	0.0%
2017	395.0	0.0	(395.0)	(100.0%)
2018	608.6	144.6	(464.0)	(76.2%)
2019	4,375.2	987.6	(3,387.6)	(77.4%)
2020	6,256.7	4,414.8	(1,841.9)	(29.4%)
2021	21,589.3	18,625.3	(2,964.0)	(13.7%)
2022	39,462.3	35,853.8	(3,608.5)	(9.1%)
2023	54,244.7	55,735.3	1,490.5	2.7%
2024	57,231.7	65,510.9	8,279.2	14.5%
2025	35,470.5	48,274.4	12,804.0	36.1%
2026	8,636.2	25,618.8	16,982.6	196.6%
2027	5,840.1	14,972.0	9,131.9	156.4%
2028	2,508.0	6,103.8	3,595.8	143.4%
2029	2,460.1	9,358.1	6,898.0	280.4%
2030	0.0	290.0	290.0	0.0%
2031	0.0	1,600.0	1,600.0	0.0%
Total	239,081.7	287,492.7	48,411.0	20.2%

Table 12-16 shows the project status changes in more detail and how scheduled queue MW have changed between December 31, 2021, and December 31, 2022. For example, 56.700.4 MW entered the queue in 2022. Of those 56,700.4 MW, 8,289.4 MW have been withdrawn. Of the total 236,941.1 MW marked as active on December 31, 2021, 7,996.4 MW were withdrawn, 3,879.4 MW were suspended, 3,051.9 MW started construction, and 402.0 MW went into service by December 31, 2022. Analysis of projects that were suspended on December 31, 2021 show that 3,755.6 MW came out of suspension and are now active as of December 31, 2022.

44 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>.

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

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

Table 12-16 Change in project status (MW): December 31, 2021 to December 31, 2022

		Status at 12/31/2022				
Status at 12/31/2021	Total at 12/31/2021	Active	In Service	Under Construction	Suspended	Withdrawn
(Entered during 2022)	0.0	48,411.0	0.0	0.0	0.0	8,289.4
Active	236,941.1	221,611.4	402.0	3,051.9	3,879.4	7,996.4
In Service	76,268.1	0.0	76,268.1	0.0	0.0	0.0
Under Construction	8,981.6	0.0	4,618.7	4,362.9	0.0	0.0
Suspended	9,009.6	3,755.6	16.3	18.8	2,401.6	2,817.3
Withdrawn	430,489.9	0.0	0.0	0.0	0.0	430,489.9
Total	761,690.2	273,778.0	81,305.0	7,433.6	6,281.0	449,592.9

On December 31, 2022, 287,492.7 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 273,778.0 MW in the status of Active on December 31, 2022, 6,759.7 MW (2.5 percent) were combined cycle projects. Of the 7,433.6 MW in the status of under construction, 3,327.7 MW (44.8 percent) were combined cycle projects. A significant amount of renewable hybrid projects (defined as solar + storage, solar + wind and wind + storage projects) have entered the queue in recent years. Of the 273,778.0 MW in the status of Active on December 31, 2022, 40,427.9 MW (14.8 percent) were renewable hybrid projects. Of the 7,433.6 MW in the status of under construction, 5.7 MW (0.08 percent) were renewable hybrid projects.

Table 12-17 Current project status (MW) by unit type: December 31, 2022

	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	52,863.0	6,759.7	3,640.3	0.0	392.9	5.0	730.0	112.8	54.2	14.4	0.0	0.0	122,535.5	40,068.9	209.0	29.0	0.0	0.0	20.0	46,193.4	150.0	273,778.0
Suspended	29.0	2,680.0	905.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,472.6	104.4	0.0	0.0	0.0	0.0	0.0	0.0	90.0	6,281.0
Under Construction	34.0	3,327.7	457.0	9.0	0.0	3.0	0.0	0.0	44.0	0.0	0.0	0.0	3,312.2	5.7	0.0	36.0	5.0	0.0	0.0	200.0	0.0	7,433.6
Total	52,926.0	12,767.4	5,002.3	9.0	392.9	8.0	730.0	112.8	98.2	14.4	0.0	0.0	128,320.3	40,179.0	209.0	65.0	5.0	0.0	20.0	46,393.4	240.0	287,492.7

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, 2022, of the 287,492.7 MW in the generation request queues in the status of active, suspended or under construction, 128,320.3 MW (44.6 percent) were solar projects, 46,393.4 MW (16.1 percent) were wind projects, 17,789.1 MW (6.2 percent) were natural gas fired projects (including combined cycle units, CTs, RICE units, and natural gas fired steam units), 40,628.0 MW (14.1 percent) were renewable hybrid projects (solar + storage, solar + wind and wind + storage units), and 65.0 MW (0.02 percent) were coal fired steam projects.

As of December 31, 2022, there are 4,184.0 MW of coal fired steam units and 1,458.6 MW of natural gas units slated for deactivation between October 1, 2022, and December 31, 2026 (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 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, 2022, there are 287,492.7 MW in queues that are not yet in service or withdrawn, of which 2.2 percent are suspended, 2.6 percent are under construction and 95.2 percent have not begun construction.

Table 12-18 Queue totals by status (MW): December 31, 2022[47]

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	716.9	0.0	0.0	16,218.6	16,935.5
U3 Expired 31-Oct-08	0.0	333.0	0.0	0.0	2,635.6	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	0.0	508.7	0.0	0.0	8,695.9	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	1,101.7	0.0	0.0	6,200.6	7,302.3
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	109.2	0.0	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	1,477.2	0.0	0.0	9,636.5	11,113.7
Y3 Expired 30-Apr-13	0.0	1,630.5	0.0	0.0	4,609.2	6,239.6
Z1 Expired 31-Oct-13	189.0	3,094.5	0.0	675.0	4,055.0	8,013.5
Z2 Expired 30-Apr-14	0.0	3,062.0	0.0	0.0	3,037.8	6,099.8
AA1 Expired 31-Oct-14	553.2	4,678.9	340.0	0.0	6,498.4	12,070.5
AA2 Expired 30-Apr-15	1,549.0	2,819.6	205.0	0.0	11,492.7	16,066.3
AB1 Expired 31-Oct-15	1,267.8	1,478.7	1,348.0	2,700.0	13,649.3	20,443.7
AB2 Expired 31-Mar-16	552.9	1,992.5	1,560.1	451.9	10,608.4	15,165.8
AC1 Expired 30-Sep-16	1,789.2	3,365.7	2,084.0	461.9	12,335.2	20,035.9
AC2 Expired 30-Apr-17	2,289.4	595.9	339.8	196.7	9,147.8	12,569.6
AD1 Expired 30-Sep-17	4,108.6	413.9	263.9	467.5	6,048.7	11,302.6
AD2 Expired 31-Mar-18	4,408.9	503.7	769.6	176.5	14,504.9	20,363.6
AE1 Expired 30-Sep-18	13,840.2	101.4	89.4	382.8	19,483.1	33,896.9
AE2 Expired 31-Mar-19	20,046.7	276.0	253.8	455.2	12,795.8	33,827.5
AF1 Expired 30-Sep-19	19,666.6	22.8	76.0	210.9	8,956.7	28,932.9
AF2 Expired 31-Mar-20	20,850.4	15.0	63.0	72.7	7,464.6	28,465.5
AG1 Expired 30-Sep-20	32,184.3	0.5	25.0	30.0	5,872.5	38,112.3
AG2 Expired 31-Mar-21	54,746.0	0.0	0.0	0.0	2,002.3	56,748.3
AH1 Expired 10-Sep-21	45,729.9	0.0	0.0	0.0	4,228.7	49,958.6
AH2 Expired 10-Mar-22	27,497.5	0.0	0.0	0.0	6,831.5	34,329.0
AI1 Expired 10-Sep-22	21,958.3	0.0	0.0	0.0	1,539.8	23,498.1
AI2 Opened 01-Oct-22	480.0	0.0	0.0	0.0	0.0	480.0
Total	273,778.0	81,305.0	7,433.6	6,281.0	449,592.9	818,390.6

47 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, 2022, 287,492.7 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, 2022[48]

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	1,739.5	0.0	230.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	668.3	221.0	0.0	0.0	0.0	0.0	0.0	3,141.6	0.0	6,000.4	0.0
	DPL	1,064.0	451.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,379.7	270.0	0.0	0.0	0.0	0.0	0.0	7,369.5	0.0	11,534.1	410.0
	JCPLC	1,086.8	0.0	0.0	0.0	0.0	0.0	30.0	0.0	0.0	0.0	0.0	0.0	716.2	215.0	0.0	0.0	0.0	0.0	0.0	12,909.2	0.0	14,957.2	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	145.4	5.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	199.4	0.0
	PSEG	1,782.0	51.1	675.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	59.2	22.6	0.0	0.0	5.0	0.0	0.0	2,610.0	0.0	5,204.9	0.0
	REC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	EMAAC Total	5,672.3	507.1	905.0	0.0	0.0	0.0	30.0	0.0	44.0	0.0	0.0	0.0	3,968.7	733.6	0.0	0.0	5.0	0.0	0.0	26,030.3	0.0	37,896.0	410.0
SWMAAC	BGE	1,457.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	54.2	0.0	0.0	0.0	154.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,666.6	0.0
	PEPCO	796.0	45.0	42.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	238.2	1,452.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,573.5	0.0
	SWMAAC Total	2,253.5	45.0	42.3	0.0	0.0	0.0	0.0	0.0	54.2	0.0	0.0	0.0	393.1	1,452.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4,240.1	0.0
WMAAC	MEC	955.2	75.0	11.5	7.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	861.4	282.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,192.8	0.0
	PE	1,267.8	85.0	585.5	0.0	3.6	3.0	0.0	0.0	0.0	0.0	0.0	0.0	6,221.0	1,606.6	0.0	0.0	0.0	0.0	0.0	587.0	0.0	10,359.5	0.0
	PPL	485.0	106.6	0.0	0.0	0.0	0.0	700.0	0.0	0.0	0.0	0.0	0.0	2,683.7	750.0	0.0	0.0	0.0	0.0	0.0	174.8	90.0	4,990.1	52.6
	WMAAC Total	2,708.0	266.6	597.0	7.5	3.6	3.0	700.0	0.0	0.0	0.0	0.0	0.0	9,766.1	2,638.8	0.0	0.0	0.0	0.0	0.0	761.8	90.0	17,542.4	52.6
Non-MAAC	AEP	11,225.9	3,360.0	842.1	0.0	379.2	0.0	0.0	51.0	0.0	0.0	0.0	0.0	43,523.5	15,918.3	0.0	65.0	0.0	0.0	0.0	3,363.0	0.0	78,727.9	80.0
	AMPT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	206.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	206.0	0.0
	APS	3,500.8	4,700.0	30.0	0.0	0.0	0.0	0.0	15.0	0.0	14.4	0.0	0.0	6,546.5	3,247.3	0.0	0.0	0.0	0.0	0.0	1,029.1	0.0	19,083.1	1,278.0
	ATSI	2,418.0	1,953.0	463.7	1.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6,878.0	891.6	0.0	0.0	0.0	0.0	0.0	297.7	0.0	12,903.5	1,522.2
	COMED	8,296.1	1,836.7	964.2	0.0	0.0	5.0	0.0	0.0	0.0	0.0	0.0	0.0	14,093.9	2,999.5	199.0	0.0	0.0	0.0	0.0	9,604.1	0.0	37,998.5	1,326.0
	DAY	340.0	0.0	20.0	0.0	10.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3,558.4	650.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4,579.3	0.0
	DUKE	527.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	678.9	40.0	10.0	0.0	0.0	0.0	0.0	0.0	0.0	1,256.1	0.0
	DLCO	505.0	0.0	0.0	0.0	0.0	0.0	0.0	46.8	0.0	0.0	0.0	0.0	88.9	107.5	0.0	0.0	0.0	0.0	20.0	0.0	0.0	768.2	0.0
	DOM	15,303.2	99.0	1,138.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	31,832.3	8,107.2	0.0	0.0	0.0	0.0	0.0	5,307.5	150.0	61,937.2	1,027.0
	EKPC	176.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6,356.0	3,214.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	9,746.1	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	42,292.2	11,948.7	3,458.0	1.5	389.3	5.0	0.0	112.8	0.0	14.4	0.0	0.0	114,192.4	35,354.6	209.0	65.0	0.0	0.0	20.0	19,601.3	150.0	227,814.2	5,233.2
Total		52,926.0	12,767.4	5,002.3	9.0	392.9	8.0	730.0	112.8	98.2	14.4	0.0	0.0	128,320.3	40,179.0	209.0	65.0	5.0	0.0	20.0	46,393.4	240.0	287,492.7	5,695.8

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.[49] 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.

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.[50] 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.[51] Using the ELCC derate factors, based on the derating of 46,393.4 MW of wind resources to 6,959.0 MW, 128,320.3 MW of solar resources to 69,293.0 MW, 40,179.0 MW of solar + storage resources to 21,696.7 MW, 209.0 MW of solar + wind resources to 112.9 MW, 240.0 MW of wind + storage resources to 36.0 MW and 52,926.0 MW of battery resources to 43,928.6 MW, the 287,492.7 MW currently under construction, suspended or active in the queue would be reduced to 161,251.0 MW.[52]

48 This data includes only projects with a status of active, under construction, or suspended.
49 See "PJM Manual 14B: PJM Region Transmission Planning Process," Rev. 51 (December 15, 2021).
50 *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>
51 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).
52 The ELCC derate adjusted MW are calculated using the four hour storage ELCC derate of 83.0 percent for battery resources, 15.0 percent ELCC derate for wind resources and 54.0 percent ELCC derate for solar resources.

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.[53] 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 3,472 projects withdrawn as of December 31, 2022, 1,735 (50.0 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 3,472 projects withdrawn, 653 (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, 2022

Milestone Completed	Projects Withdrawn	Percent	Average Days	Maximum Days
Never Started	698	20.1%	277	1,193
Feasibility Study	1,037	29.9%	269	1,633
System Impact Study	766	22.1%	723	3,248
Facilities Study	318	9.2%	1,146	4,107
Construction Service Agreement (CSA) or beyond	653	18.8%	1,393	7,864
Total	3,472	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 1,120 days, or 3.1 years, between entering a queue and going into service. For withdrawn projects, there is an average time of 640 days, or 1.8 years, between entering a queue and withdrawing.

Table 12-21 Project queue times by status (days): December 31, 2022[54]

Status	Average (Days)	Standard Deviation	Maximum
Active	799	484	5,766
In-Service	1,120	798	5,306
Suspended	1,608	601	3,348
Under Construction	1,864	664	4,964
Withdrawn	640	748	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 3,170 projects in the queue as of December 31, 2022, 180 (5.7 percent) had a completed feasibility study and 492 (15.5 percent) had a completed construction service agreement.

Table 12-22 Project queue times by milestone (days): December 31, 2022

Milestone Reached	Number of Projects	Percent of Total Projects	Average Days	Maximum Days
Under Review	1,721	54.3%	1,147	1,523
Feasibility Study	180	5.7%	872	1,282
System Impact Study	720	22.7%	1,121	1,986
Facilities Study	57	1.8%	1,546	2,396
Construction Service Agreement (CSA) or beyond	492	15.5%	1,664	5,766
Total	3,170	100.0%		

53 See "PJM Manual 14B: PJM Region Transmission Planning Process," Rev. 51 (December 15, 2021).
54 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 for battery projects entering the queue in 2019.

Table 12-23 Average time in queue (days) by fuel type and year submitted (In Service Projects): December 31, 2022[55]

Unit Type	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Battery	983	609	417	692	789	1,082	941	383	293	600	544		
CC	1,310	1,551	1,663	1,419	1,175	1,125	1,017	908	309	512			
CT - Natural Gas	1,131	804	953	1,073	734	619	1,404	1,038	805	395	319		
CT - Oil	717		259							280			
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	1,395	969	1,014	1,003	1,624	1,400	1,141	892	581	479		
Solar + Storage									553				
Solar + Wind													
Steam - Coal	745		513	1,010	583	853	684	647	1,122				
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	1,398	934		884		
Wind + Storage							1,189						

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.[56] 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, 11.1 percent of the queued MW have gone into service. The completion rate for battery projects increases to 30.1 percent when battery projects complete the facility study agreement and further increases to 37.7 percent when battery projects complete the construction service agreement. Of all battery projects to enter the queue, only 0.4 percent of the queued MW have gone into service.

55 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.
56 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, 2022

Unit Type	Completion Rate (SIS)	Completion Rate (FSA)	Completion Rate (CSA)	Completion Rate (ALL)
Battery	11.1%	30.1%	37.7%	0.4%
CC	32.9%	49.3%	73.2%	15.8%
CT - Natural Gas	65.5%	79.8%	84.0%	43.5%
CT - Oil	35.4%	59.7%	90.8%	25.4%
CT - Other	12.1%	18.4%	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	42.5%	60.0%	67.2%	20.9%
Nuclear	34.9%	42.1%	51.3%	28.5%
RICE - Natural Gas	30.7%	42.8%	47.4%	25.9%
RICE - Oil	34.0%	59.7%	59.7%	24.6%
RICE - Other	89.0%	91.4%	92.0%	78.1%
Solar	21.4%	47.1%	57.4%	2.9%
Solar + Storage	0.0%	1.3%	2.3%	0.0%
Solar + Wind	0.0%	0.0%	0.0%	0.0%
Steam - Coal	13.7%	25.5%	37.6%	6.3%
Steam - Natural Gas	90.5%	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	18.4%	35.6%	51.7%	7.2%
Wind + Storage	0.0%	0.0%	0.0%	0.0%

On December 31, 2022, 287,492.7 MW were in generation request queues in the status of active, under construction or suspended. Of the total 287,492.7 MW in the queue, 172,091.6 MW (59.1 percent) have reached at least the SIS milestone and 115,401.1 MW (40.1 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), 41,120.1 MW (14.3 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, 2022. 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, 2022.

Table 12-25 Percent of all projects (MW energy) to go in service by unit type and year submitted to the queue: December 31, 2022

Unit Type	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
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%	0.0%
CC	14.6%	24.5%	30.8%	35.6%	53.6%	9.2%	11.7%	6.1%	1.2%	0.5%	0.0%	0.0%	0.0%
CT - Natural Gas	100.0%	98.3%	71.6%	42.2%	32.0%	0.2%	11.1%	32.3%	7.4%	2.5%	0.4%	0.0%	0.0%
CT - Oil	100.0%	N/A	1.2%	0.0%	0.0%	N/A	N/A	N/A	0.0%	30.8%	0.0%	N/A	N/A
CT - Other	28.8%	26.2%	36.1%	100.0%	0.0%	100.0%	N/A	0.0%	N/A	N/A	N/A	0.0%	N/A
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%	N/A
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%	N/A
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%	N/A
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	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%	N/A
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	0.0%
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	N/A
Solar	10.7%	8.1%	16.9%	24.4%	30.7%	23.9%	21.2%	2.2%	0.6%	0.8%	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%	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%	N/A
Steam - Coal	100.0%	0.0%	1.4%	68.4%	1.2%	23.4%	37.5%	100.0%	22.4%	0.0%	N/A	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	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%	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%	N/A
WInd	6.1%	3.4%	2.5%	6.3%	20.7%	12.5%	12.3%	2.6%	0.6%	0.0%	0.0%	0.0%	0.0%
Wind + Storage	N/A	N/A	N/A	N/A	N/A	N/A	100.0%	0.0%	N/A	N/A	N/A	N/A	0.0%
All	11.7%	19.0%	25.9%	34.5%	40.3%	11.9%	15.0%	4.1%	1.0%	0.5%	0.0%	0.0%	0.0%

Table 12-26 shows the total MW that went in service each year, by unit type, since 1999. In 2022, 1,979.6 MW from the queue went in service. Of the 1,979.6 MW that went in service, 1,200.9 MW (60.7 percent) were combined cycle units, 625.2 MW (31.6 percent) were solar units and 153.5 MW (7.8 percent) were combustion turbine natural gas units.

Table 12-26 Total (MW Energy) by unit type and year project went in service: December 31, 2022

Unit Type	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Battery	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	27.4	4.5	23.0	24.0	110.4	10.0	2.0	41.0	25.5	0.0	1.5	0.0
CC	0.0	0.0	100.0	2,608.0	2,785.0	2,845.0	15.1	1,196.0	22.0	177.0	52.0	136.0	1,869.0	162.7	82.2	2,155.7	2,977.7	5,418.0	3,888.1	10,865.0	2,881.4	88.0	3,424.7	1,200.9
CT - Natural Gas	0.0	401.6	432.0	2,442.0	638.7	61.3	993.0	39.3	97.0	821.0	181.7	97.8	850.4	393.0	95.0	125.2	317.9	72.0	212.0	388.0	104.0	127.0	328.4	153.5
CT - Oil	0.0	0.0	315.0	6.5	0.0	33.0	292.0	7.5	21.0	15.3	85.6	0.0	23.9	2.0	0.5	2.0	0.0	0.0	0.0	0.0	0.0	4.0	0.0	0.0
CT - Other	0.0	0.0	10.0	0.0	0.0	4.1	0.0	0.0	11.0	6.9	0.0	18.2	0.0	70.7	17.6	6.0	8.0	5.9	0.0	0.0	3.2	0.0	0.0	0.0
Fuel Cell	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.9	0.0	0.0	0.0	0.0
Hydro - Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	340.0	16.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	34.0	0.0	0.0	0.0	0.0
Hydro - Run of River	0.0	0.0	0.0	107.0	196.0	2.0	0.0	5.7	2.5	0.0	6.2	180.0	27.0	0.0	6.0	28.9	160.5	0.0	29.5	5.5	0.0	2.4	0.0	0.0
Nuclear	0.0	0.0	165.0	15.0	44.0	0.0	1,693.0	242.0	130.0	115.0	0.0	281.0	422.0	328.0	117.0	80.0	54.0	133.8	130.0	0.0	0.0	0.0	0.0	0.0
RICE - Natural Gas	0.0	0.0	0.0	0.0	0.0	8.0	29.0	2.0	19.5	0.0	0.0	10.5	0.0	0.0	0.0	0.0	18.9	20.9	19.9	5.2	39.8	0.0	0.0	0.0
RICE - Oil	0.0	0.0	0.0	0.0	0.0	23.3	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	4.0	0.0	0.0
RICE - Other	0.0	1.2	0.0	2.9	17.2	0.0	27.5	44.9	86.6	57.6	38.8	13.8	43.0	2.0	109.0	0.0	3.8	19.3	22.4	0.0	0.8	0.0	0.0	0.0
Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.3	5.1	6.8	137.2	98.9	44.4	59.8	172.1	300.8	332.9	285.3	559.0	1,660.0	807.5	625.2
Solar + Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	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	0.0	0.0
Solar + Wind	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	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 - Coal	12.0	20.0	59.0	21.0	0.0	37.0	20.0	14.0	55.0	718.0	123.0	177.0	97.0	708.0	48.0	16.0	92.5	0.0	47.0	24.0	20.0	0.0	11.0	0.0
Steam - Natural Gas	0.0	0.0	2.5	10.0	0.0	0.0	0.0	0.0	25.0	145.0	0.0	0.0	5.5	0.0	0.0	0.0	0.0	696.5	0.0	0.0	0.0	64.0	0.0	0.0
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	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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	529.0	0.0	22.5	0.0	122.5	0.9	0.0	50.0	3.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
WInd	0.0	0.0	0.0	15.0	190.0	20.4	7.5	380.0	1,053.3	729.8	622.0	1,183.5	326.6	1,424.5	150.0	500.0	455.0	465.8	700.7	762.0	535.0	1,008.6	310.0	0.0
Wind + Storage	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	0.0	0.0	0.0	0.0	0.0
Total	28.3	422.8	1,083.5	5,227.4	3,870.9	3,034.1	3,077.1	2,460.4	1,522.9	2,811.4	1,454.4	2,243.1	3,829.8	3,194.2	742.7	3,001.4	4,370.8	7,143.0	5,384.5	12,411.9	4,169.8	2,958.0	4,883.1	1,979.6

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 12-27 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 5,050 projects entered from January 2015 through December 2022, 3,742 projects (74.1 percent) were renewable. Of the 517 projects entered in 2022, 359 projects (69.4 percent) were renewable.

Table 12-27 Number of projects entered in the queue: December 31, 2022

	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	344	95	440
2019	0	547	150	697
2020	2	783	213	998
2021	0	984	351	1,335
2022	0	359	158	517
Total	72	5,085	2,545	7,702

As of December 31, 2022, renewable projects make up 75.6 percent of all projects in the queue and those projects account for 75.2 percent of the nameplate MW currently active, suspended or under construction in the queue as of December 31, 2022 (Table 12-28).

Table 12-28 Queue details by fuel group: December 31, 2022

Fuel Group	Number of Projects	Percent of Projects	MW	Percent MW
Nuclear	4	0.1%	98.2	0.0%
Renewable	2,395	75.6%	216,192.4	75.2%
Traditional	771	24.3%	71,202.0	24.8%
Total	3,170	100.0%	287,492.7	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 12-29 shows the total MW of all projects in the queue as of December 31, 2022, in the status of active, suspended and under construction, by unit type. Table 12-29 also shows the total MW for each fuel type adjusted based on current historical completion rates and for battery, solar and wind ELCC derates. Of the 12,767.4 MW of combined cycle projects in the queue, 7,799.0 MW (61.1 percent) are expected to go in service based on historical completion rates as of December 31, 2022. Of the 216,192.4 MW of renewable projects in the queue, only 28,472.7 MW (13.2 percent) are expected to go in service based on historical completion rates. Of the 216,192.4 MW of renewable projects in the queue, only 13,009.8 MW (6.0 percent) of capacity resources are expected to go into service, based on both historical completion rates and ELCC derate factors for battery, wind and solar.

Table 12-29 Queue totals for projects (active, suspended and under construction) by unit type adjusted based on current historical completion rates and ELCC battery, solar and wind derates (MW): December 31, 2022[57]

Unit Type	MW in Queue	Completion Rate Adjusted MW in Queue	Completion Rate and ELCC Adjusted MW in Queue
Battery	52,926.0	1,328.7	1,102.8
CC	12,767.4	7,799.0	7,799.0
CT - Natural Gas	5,002.3	3,396.3	3,396.3
CT - Oil	9.0	8.2	8.2
CT - Other	392.9	33.0	33.0
Fuel Cell	8.0	2.5	2.5
Hydro - Pumped Storage	730.0	707.2	707.2
Hydro - Run of River	112.8	52.3	52.3
Nuclear	98.2	45.4	45.4
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	128,320.3	20,712.9	11,185.0
Solar + Storage	40,179.0	33.8	18.2
Solar + Wind	209.0	0.0	0.0
Steam - Coal	65.0	23.1	23.1
Steam - Natural Gas	5.0	4.6	4.6
Steam - Oil	0.0	0.0	0.0
Steam - Other	20.0	5.4	5.4
Wind	46,393.4	6,964.0	1,044.6
Wind + Storage	240.0	0.0	0.0
Total	287,492.7	41,120.1	25,431.3

Queue Analysis by Unit Type and Project Classification

Table 12-30 shows the current status of all generation queue projects by unit type and project classification from January 1, 1997, through December 31, 2022. As of December 31, 2022, 7,702 projects, representing 818,390.6 MW, have entered the queue process since its inception. Of those, 1,060 projects, representing 81,305.0 MW, went into service. Of the projects that entered the queue process, 3,472 projects, representing 449,592.9 MW (54.9 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 6,156 projects have been classified as new generation and 1,546 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 6,016 projects (78.1 percent) of all 7,702 generation queue projects to enter the queue since January 1, 1997.

57 The derate adjusted MW in this table are calculated using the four hour storage ELCC derate of 83.0 percent for battery resources, 15.0 percent ELCC derate for wind resources and 54.0 percent ELCC derate for solar resources.

Table 12-30 Status of all generation queue projects: January 1, 1997 through December 31, 2022

		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	65	49	10	25	3	0	10	2	10	0	55	205	1	0	8	5	0	4	98	0	574
	Upgrade	7	109	122	16	5	0	3	19	42	9	2	16	46	0	0	56	10	0	8	15	1	486
Under Construction	New Generation	3	2	2	0	0	0	0	0	0	0	0	0	51	2	0	0	1	0	0	1	0	62
	Upgrade	0	8	11	7	0	1	0	0	1	0	0	0	12	1	0	1	0	0	0	2	0	44
Suspended	New Generation	4	4	2	0	0	0	0	0	0	0	0	0	46	15	0	0	0	0	0	0	1	72
	Upgrade	0	0	0	0	0	0	0	0	0	0	0	0	4	1	0	0	0	0	0	0	0	5
Withdrawn	New Generation	221	436	29	10	82	26	2	44	9	29	12	16	1,526	97	0	55	1	0	34	473	0	3,102
	Upgrade	60	102	19	15	13	2	0	5	15	0	3	3	81	2	0	15	2	0	2	31	0	370
Active	New Generation	412	6	4	0	6	0	2	5	0	1	0	0	1,423	385	2	0	0	0	1	98	1	2,346
	Upgrade	253	18	21	0	2	2	1	2	3	0	0	0	272	43	0	2	0	0	0	21	1	641
Total Projects	New Generation	664	513	86	20	113	29	4	59	11	40	12	71	3,251	500	2	63	7	0	39	670	2	6,156
	Upgrade	320	237	173	38	20	5	4	26	61	9	5	19	415	47	0	74	12	0	10	69	2	1,546

Table 12-31 shows the totals in Table 12-30 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, 70.9 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 9.9 percent of hydro run of river upgrades are active in the queue.

Table 12-31 Status of all generation queue projects as a percent of total projects by classification: January 1, 1997 through December 31, 2022

		Percent of Projects																					
Project Status	Project Classification	Battery	CC	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
In Service	New Generation	3.6%	12.7%	57.0%	50.0%	22.1%	10.3%	0.0%	16.9%	18.2%	25.0%	0.0%	77.5%	6.3%	0.2%	0.0%	12.7%	71.4%	0.0%	10.3%	14.6%	0.0%	9.3%
	Upgrade	2.2%	46.0%	70.5%	42.1%	25.0%	0.0%	75.0%	73.1%	68.9%	100.0%	40.0%	84.2%	11.1%	0.0%	0.0%	75.7%	83.3%	0.0%	80.0%	21.7%	50.0%	31.4%
Under Construction	New Generation	0.5%	0.4%	2.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.6%	0.4%	0.0%	0.0%	14.3%	0.0%	0.0%	0.1%	0.0%	1.0%
	Upgrade	0.0%	3.4%	6.4%	18.4%	0.0%	20.0%	0.0%	0.0%	1.6%	0.0%	0.0%	0.0%	2.9%	2.1%	0.0%	1.4%	0.0%	0.0%	0.0%	2.9%	0.0%	2.8%
Suspended	New Generation	0.6%	0.8%	2.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.4%	3.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	50.0%	1.2%
	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%	1.0%	2.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.3%
Withdrawn	New Generation	33.3%	85.0%	33.7%	50.0%	72.6%	89.7%	50.0%	74.6%	81.8%	72.5%	100.0%	22.5%	46.9%	19.4%	0.0%	87.3%	14.3%	0.0%	87.2%	70.6%	0.0%	50.4%
	Upgrade	18.8%	43.0%	11.0%	39.5%	65.0%	40.0%	0.0%	19.2%	24.6%	0.0%	60.0%	15.8%	19.5%	4.3%	0.0%	20.3%	16.7%	0.0%	20.0%	44.9%	0.0%	23.9%
Active	New Generation	62.0%	1.2%	4.7%	0.0%	5.3%	0.0%	50.0%	8.5%	0.0%	2.5%	0.0%	0.0%	43.8%	77.0%	100.0%	0.0%	0.0%	0.0%	2.6%	14.6%	50.0%	38.1%
	Upgrade	79.1%	7.6%	12.1%	0.0%	10.0%	40.0%	25.0%	7.7%	4.9%	0.0%	0.0%	0.0%	65.5%	91.5%	0.0%	2.7%	0.0%	0.0%	0.0%	30.4%	50.0%	41.5%

Table 12-32 shows the total MW of projects in the PJM generation queue by unit type and project classification. For example, the 473 new generation wind projects that have been withdrawn from the queue as of December 31, 2022, (as shown in Table 12-30) constitute 87,023.6 MW. The 436 new generation combined cycle projects that have been withdrawn in the same time period constitute 219,816.7 MW.

Table 12-32 Status of all generation (MW) in the generation queue: January 1, 1997 through December 31, 2022

		Project MW																					
Project Status	Project Classification	Battery	CC	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
In Service	New Generation	224.9	37,441.9	6,532.8	676.5	149.2	1.9	0.0	371.5	1,639.0	156.4	0.0	440.1	4,742.8	1.1	0.0	1,343.0	723.0	0.0	60.9	10,601.0	0.0	65,106.1
	Upgrade	44.4	7,507.5	2,839.0	131.8	12.3	0.0	390.0	387.6	2,310.8	17.3	27.3	50.7	355.4	0.0	0.0	976.5	225.5	0.0	667.8	238.7	16.3	16,198.9
Under Construction	New Generation	34.0	2,250.0	208.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3,071.1	2.6	0.0	0.0	5.0	0.0	0.0	200.0	0.0	5,770.7
	Upgrade	0.0	1,077.7	249.0	9.0	0.0	3.0	0.0	0.0	44.0	0.0	0.0	0.0	241.1	3.2	0.0	36.0	0.0	0.0	0.0	0.0	0.0	1,663.0
Suspended	New Generation	29.0	2,680.0	905.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,375.7	54.4	0.0	0.0	0.0	0.0	0.0	0.0	90.0	6,134.1
	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	96.9	50.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	146.9
Withdrawn	New Generation	8,384.2	219,816.7	4,426.3	1,735.0	1,244.2	5.5	500.0	2,066.5	8,161.0	481.2	63.9	88.6	50,134.8	9,244.8	0.0	33,511.6	27.0	0.0	1,050.9	87,023.6	0.0	427,965.7
	Upgrade	1,374.6	12,919.0	1,001.0	593.0	72.5	0.9	0.0	105.1	1,066.0	0.0	19.6	10.0	1,890.3	3.7	0.0	885.0	6.0	0.0	37.1	1,643.4	0.0	21,627.2
Active	New Generation	42,639.8	5,441.0	2,301.0	0.0	392.9	0.0	700.0	58.6	0.0	14.4	0.0	0.0	111,471.4	38,533.6	209.0	0.0	0.0	0.0	20.0	41,850.3	150.0	243,781.9
	Upgrade	10,223.2	1,318.7	1,339.3	0.0	0.0	5.0	30.0	54.2	54.2	0.0	0.0	0.0	11,064.1	1,535.3	0.0	29.0	0.0	0.0	0.0	4,343.0	0.0	29,996.1
Total Projects	New Generation	51,311.9	267,629.6	14,373.1	2,411.5	1,786.4	7.4	1,200.0	2,496.5	9,800.0	652.0	63.9	528.7	171,795.8	47,836.4	209.0	34,854.6	755.0	0.0	1,131.8	139,674.9	240.0	748,758.5
	Upgrade	11,642.2	22,822.9	5,428.3	733.8	84.8	8.9	420.0	546.9	3,475.0	17.3	46.9	60.7	13,647.8	1,592.2	0.0	1,926.5	231.5	0.0	704.9	6,225.2	16.3	69,632.1

Table 12-33 shows the MW totals in Table 12-32 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, 62.3 percent of wind project MW classified as new generation have been withdrawn from the queue between January 1, 1997, and December 31, 2022.

Table 12-33 Status of all generation queue projects as percent of total MW in project classification: January 1, 1997 through December 31, 2022

		Percent of Total Projects by Classification																					
Project Status	Project Classification	Battery	CC	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
In Service	New Generation	0.4%	14.0%	45.5%	28.1%	8.4%	26.2%	0.0%	14.9%	16.7%	24.0%	0.0%	83.2%	2.8%	0.0%	0.0%	3.9%	95.8%	0.0%	5.4%	7.6%	0.0%	8.7%
	Upgrade	0.4%	32.9%	52.3%	18.0%	14.5%	0.0%	92.9%	70.9%	66.5%	100.0%	58.2%	83.5%	2.6%	0.0%	0.0%	50.7%	97.4%	0.0%	94.7%	3.8%	100.0%	23.3%
Under Construction	New Generation	0.1%	0.8%	1.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.8%	0.0%	0.0%	0.0%	0.7%	0.0%	0.0%	0.1%	0.0%	0.8%
	Upgrade	0.0%	4.7%	4.6%	1.2%	0.0%	33.5%	0.0%	0.0%	1.3%	0.0%	0.0%	0.0%	1.8%	0.2%	0.0%	1.9%	0.0%	0.0%	0.0%	0.0%	0.0%	2.4%
Suspended	New Generation	0.1%	1.0%	6.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.4%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	37.5%	0.8%
	Upgrade	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.7%	3.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%
Withdrawn	New Generation	16.3%	82.1%	30.8%	71.9%	69.7%	73.8%	41.7%	82.8%	83.3%	73.8%	100.0%	16.8%	29.2%	19.3%	0.0%	96.1%	3.6%	0.0%	92.9%	62.3%	0.0%	57.2%
	Upgrade	11.8%	56.6%	18.4%	80.8%	85.5%	10.6%	0.0%	19.2%	30.7%	0.0%	41.8%	16.5%	13.9%	0.2%	0.0%	45.9%	2.6%	0.0%	5.3%	26.4%	0.0%	31.1%
Active	New Generation	83.1%	2.0%	16.0%	0.0%	22.0%	0.0%	58.3%	2.3%	0.0%	2.2%	0.0%	0.0%	64.9%	80.6%	100.0%	0.0%	0.0%	0.0%	1.8%	30.0%	62.5%	32.6%
	Upgrade	87.8%	5.8%	24.7%	0.0%	0.0%	55.9%	7.1%	9.9%	1.6%	0.0%	0.0%	0.0%	81.1%	96.4%	0.0%	1.5%	0.0%	0.0%	0.0%	69.8%	0.0%	43.1%

Table 12-34 shows the project MW that entered the PJM generation queue by unit type and year of entry. Since 2016, 70.0 percent of all new projects entering the generation queue have been combined cycle (10.1 percent), wind (17.2 percent) or solar projects (42.7 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, 2022, 49,893.9 MW of renewable hybrid units have entered the queue.

Table 12-34 Queue project MW by unit type and queue entry year: January 1, 1997 through December 31, 2022

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	10,955.5	0.0	41,663.1
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	172.5	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	28,267.8
2012	142.6	18,014.8	102.1	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	22,566.8
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	1,296.6	0.0	13,952.1
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	1,589.0	0.0	0.0	1,730.5	27.0	0.0	43.1	1,691.3	0.0	19,099.6
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	59.0	23.5	0.0	38.9	11,558.5	85.6	0.0	80.0	77.0	0.0	0.0	3,448.7	16.3	35,708.9
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	13,652.8	424.9	0.0	14.0	17.0	0.0	0.0	5,137.0	90.0	25,726.3
2018	1,463.7	11,080.1	2,647.4	14.0	0.0	0.0	700.0	2.4	28.1	0.0	0.0	0.8	19,804.0	4,543.9	0.0	49.0	0.0	0.0	0.0	17,707.9	0.0	58,041.3
2019	5,511.3	3,332.5	1,587.1	13.0	0.0	3.0	500.0	99.0	0.0	0.0	0.0	0.0	27,612.5	9,557.9	0.0	11.0	0.0	0.0	0.0	11,585.4	0.0	59,812.6
2020	11,312.9	50.0	846.6	4.0	0.0	0.0	0.0	80.2	100.0	0.0	0.0	0.0	37,731.6	10,309.6	199.0	0.0	11.0	0.0	0.0	6,915.9	0.0	67,560.7
2021	25,907.1	2,129.0	771.0	0.0	392.9	5.0	30.0	23.5	0.0	14.4	0.0	0.0	49,138.7	14,871.2	10.0	0.0	0.0	0.0	20.0	11,160.0	0.0	104,472.8
2022	17,218.0	143.0	20.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6.6	0.0	14,526.8	9,633.6	0.0	0.0	0.0	0.0	0.0	14,214.3	150.0	55,912.3
Total	62,954.1	290,452.5	19,801.4	3,145.3	1,871.1	16.3	1,620.0	3,043.4	13,275.0	669.3	110.8	589.4	185,443.6	49,428.6	209.0	36,781.1	986.5	0.0	1,836.7	145,900.1	256.3	818,390.6

Combined Cycle Project Analysis

Table 12-35 shows the status of all combined cycle projects by number of projects that entered PJM generation queues from January 1, 1997, through December 31, 2022, by zone. Of the 38 combined cycle projects classified as new generation or upgrade currently active, suspended or under construction in the PJM generation queue, nine projects (23.7 percent) are located in the APS Zone.

Table 12-35 Status of all combined cycle queue projects by zone (number of projects): January 1, 1997 through December 31, 2022

		Number of Projects																						
Project Status	Project Classification	ACEC	AEP	AMPT	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	6	0	3	4	2	2	0	2	0	7	2	0	7	4	0	5	2	4	8	6	0	65
	Upgrade	3	13	0	9	5	0	5	0	0	0	16	5	0	6	4	0	13	3	4	9	14	0	109
Under Construction	New Generation	0	1	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2
	Upgrade	0	3	0	1	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	2	1	0	8
Suspended	New Generation	0	2	0	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	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
Withdrawn	New Generation	23	20	0	45	13	8	16	1	1	2	18	16	3	26	25	0	44	41	35	42	55	2	436
	Upgrade	8	8	0	10	4	0	4	0	1	0	11	5	0	8	7	0	3	5	5	8	15	0	102
Active	New Generation	0	0	0	5	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	6
	Upgrade	0	1	0	3	1	0	2	0	0	0	3	1	0	0	0	0	1	2	2	1	1	0	18
Total Projects	New Generation	24	29	0	53	19	10	20	1	3	2	25	18	3	33	29	0	49	43	39	50	61	2	513
	Upgrade	11	25	0	23	10	0	11	0	1	0	30	11	0	14	12	0	17	10	11	20	31	0	237

Table 12-36 shows the status of all combined cycle projects by MW that entered PJM generation queues from January 1, 1997, through December 31, 2022, by zone. Of the 12,767.4 MW of combined cycle projects classified as new generation or upgrade currently active, suspended or under construction in the PJM generation queue, 4,700.0 MW (36.8 percent) are located in the APS Zone.

Table 12-36 Status of all combined cycle queue projects by zone (MW): January 1, 1997 through December 31, 2022

		Project MW																						
Project Status	Project Classification	ACEC	AEP	AMPT	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
In Service	New Generation	650.0	4,511.0	0.0	1,970.0	3,751.0	140.0	1,800.9	0.0	533.0	0.0	5,828.6	319.2	0.0	1,665.8	2,557.0	0.0	2,665.0	1,900.0	1,560.0	5,142.0	2,448.5	0.0	37,441.9
	Upgrade	229.0	475.0	0.0	939.7	344.0	0.0	633.6	0.0	0.0	0.0	978.0	102.0	0.0	110.0	113.9	0.0	1,075.5	112.3	228.6	1,320.0	845.9	0.0	7,507.5
Under Construction	New Generation	0.0	1,100.0	0.0	0.0	0.0	0.0	1,150.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,250.0
	Upgrade	0.0	825.0	0.0	20.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	75.0	0.0	0.0	0.0	0.0	106.6	51.1	0.0	1,077.7
Suspended	New Generation	0.0	1,150.0	0.0	0.0	955.0	0.0	575.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,680.0
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Withdrawn	New Generation	8,542.4	13,559.5	0.0	21,832.1	8,641.0	3,122.1	10,817.0	1,150.0	134.5	665.0	12,961.0	5,145.4	991.8	13,562.6	13,001.0	0.0	24,140.0	16,114.0	22,268.2	18,917.7	24,244.6	6.9	219,816.7
	Upgrade	157.0	746.0	0.0	1,284.0	636.0	0.0	1,735.0	0.0	36.0	0.0	780.4	959.0	0.0	413.0	1,742.0	0.0	240.0	1,040.6	229.1	703.0	2,217.9	0.0	12,919.0
Active	New Generation	0.0	0.0	0.0	4,501.0	940.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5,441.0
	Upgrade	0.0	285.0	0.0	179.0	58.0	0.0	111.7	0.0	0.0	0.0	99.0	451.0	0.0	0.0	0.0	0.0	5.0	85.0	45.0	0.0	0.0	0.0	1,318.7
Total Projects	New Generation	9,192.4	20,320.5	0.0	28,303.1	14,287.0	3,262.1	14,342.9	1,150.0	667.5	665.0	18,789.6	5,464.6	991.8	15,228.4	15,558.0	0.0	26,805.0	18,014.0	23,828.2	24,059.7	26,693.1	6.9	267,629.6
	Upgrade	386.0	2,331.0	0.0	2,422.7	1,038.0	0.0	2,480.3	0.0	36.0	0.0	1,857.4	1,512.0	0.0	523.0	1,930.9	0.0	1,320.5	1,237.9	502.7	2,129.6	3,114.9	0.0	22,822.9

Of the 38 combined cycle units in the queue as of December 31, 2022, in the status of Active, Under Construction or Suspended, 20 units, representing 4,303.4 MW had a projected in service date prior to December 31, 2022 and 18 units, representing 8,464.0 MW had a projected in service date between January 1, 2023, and November 2, 2026.

Combustion Turbine - Natural Gas Project Analysis

Table 12-37 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, 2022, by zone. Of the 40 combustion turbine natural gas projects classified as new generation or upgrade currently active, suspended or under construction in the PJM generation queue, eight projects (20.0 percent) are located in the COMED Zone.

Table 12-37 Status of all combustion turbine - natural gas generation queue projects by zone (number of projects): January 1, 1997 through December 31, 2022

		Number of Projects																						
Project Status	Project Classification	ACEC	AEP	AMPT	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	0	6	0	3	0	0	0	2	3	6	0	2	1	0	2	4	2	4	9	0	49
	Upgrade	4	10	0	10	3	0	17	6	0	0	28	8	0	5	2	0	4	4	3	4	14	0	122
Under Construction	New Generation	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	2
	Upgrade	0	0	0	0	2	0	2	0	0	0	0	0	0	0	3	0	0	4	0	0	0	0	11
Suspended	New Generation	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	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	0
Withdrawn	New Generation	1	6	0	0	0	2	1	1	0	0	4	0	1	1	0	0	1	5	0	1	5	0	29
	Upgrade	2	1	0	1	1	0	3	2	0	2	3	0	0	0	1	0	0	1	2	0	0	0	19
Active	New Generation	0	1	0	0	0	0	0	0	0	0	2	0	0	0	0	0	0	1	0	0	0	0	4
	Upgrade	2	3	0	1	4	0	5	1	0	0	1	0	0	0	0	0	0	1	3	0	0	0	21
Total Projects	New Generation	7	7	0	6	0	5	2	1	0	2	9	6	1	3	1	0	3	11	2	5	15	0	86
	Upgrade	8	14	0	12	10	0	27	9	0	2	32	8	0	5	6	0	4	10	8	4	14	0	173

Table 12-38 shows the status of all combustion turbine natural gas projects by MW that entered PJM generation queues from January 1, 1997, through December 31, 2022, by zone. Of the 5,002.3 MW of combustion turbine natural gas projects classified as new generation or upgrade currently active, suspended or under construction in the PJM generation queue, 1,138.0 MW (22.7 percent) are located in the DOM Zone.

Table 12-38 Status of all combustion turbine - natural gas queue projects by zone (MW): January 1, 1997 through December 31, 2022

		Project MW																						
Project Status	Project Classification	ACEC	AEP	AMPT	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	0.0	1,176.0	0.0	23.0	0.0	0.0	0.0	219.4	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	6,532.8
	Upgrade	43.7	227.0	0.0	269.7	100.0	0.0	478.0	83.5	0.0	0.0	925.7	86.0	0.0	20.0	36.1	0.0	42.0	28.0	32.0	252.3	215.0	0.0	2,839.0
Under Construction	New Generation	0.0	0.0	0.0	0.0	0.0	0.0	190.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	18.0	0.0	0.0	0.0	0.0	208.0
	Upgrade	0.0	0.0	0.0	0.0	5.0	0.0	220.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	11.5	0.0	0.0	12.5	0.0	0.0	0.0	0.0	249.0
Suspended	New Generation	230.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	675.0	0.0	905.0
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Withdrawn	New Generation	7.5	1,519.0	0.0	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	0.0	4.0	25.0	0.0	373.0	104.0	0.0	18.5	57.0	0.0	0.0	0.0	0.0	0.0	0.0	235.0	13.0	0.0	0.0	0.0	1,001.0
Active	New Generation	0.0	700.0	0.0	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	463.0	0.0	0.0	0.0	0.0	2,301.0
	Upgrade	0.0	142.1	0.0	30.0	458.7	0.0	554.2	20.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	92.0	42.3	0.0	0.0	0.0	1,339.3
Total Projects	New Generation	598.2	2,219.0	0.0	1,176.0	0.0	176.6	200.0	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	14,373.1
	Upgrade	209.2	375.1	0.0	303.7	588.7	0.0	1,625.2	207.5	0.0	18.5	982.7	86.0	0.0	20.0	47.6	0.0	42.0	367.5	87.3	252.3	215.0	0.0	5,428.3

Wind Project Analysis

Table 12-39 shows the status of all wind generation projects, by number of projects that entered PJM generation queues from January 1, 1997, through December 31, 2022, by zone. Of the 122 wind projects classified as new generation or upgrade currently active, suspended or under construction in the PJM generation queue, 45 projects (36.9 percent) are located in the COMED Zone.

Table 12-39 Status of all wind generation queue projects by zone (number of projects): January 1, 1997 through December 31, 2022

		Number of Projects																						
Project Status	Project Classification	ACEC	AEP	AMPT	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	0	18	0	0	26	0	0	0	3	0	0	0	0	0	0	23	0	8	0	0	98
	Upgrade	0	0	0	3	0	0	7	0	0	0	0	0	0	0	0	0	0	5	0	0	0	0	15
Under Construction	New Generation	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
	Upgrade	0	0	0	0	0	0	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2
Suspended	New Generation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Upgrade	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Withdrawn	New Generation	19	117	0	46	10	0	110	15	0	0	21	13	1	7	0	0	0	63	0	50	1	0	473
	Upgrade	2	2	0	7	0	0	8	0	0	0	3	1	0	0	0	0	0	6	0	2	0	0	31
Active	New Generation	5	18	0	7	1	0	35	0	0	0	8	9	0	9	0	0	0	3	0	1	2	0	98
	Upgrade	0	1	0	1	0	0	7	0	0	0	0	4	0	4	0	0	0	4	0	0	0	0	21
Total Projects	New Generation	25	154	0	71	11	0	172	15	0	0	32	22	1	16	0	0	0	89	0	59	3	0	670
	Upgrade	2	3	0	11	0	0	24	0	0	0	3	5	0	4	0	0	0	15	0	2	0	0	69

Table 12-40 shows the status of all wind projects by MW that entered PJM generation queues from January 1, 1997, through December 31, 2022, by zone. Of the 46,393.4 MW of wind projects classified as new generation or upgrade currently active, suspended or under construction in the PJM generation queue, 12,909.2 MW (27.8 percent) are located in the JCPLC Zone.

Table 12-40 Status of all wind generation queue projects by zone (MW): January 1, 1997 through December 31, 2022

		Project MW																						
Project Status	Project Classification	ACEC	AEP	AMPT	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
In Service	New Generation	7.5	3,544.6	0.0	1,364.0	0.0	0.0	4,088.9	0.0	0.0	0.0	322.5	0.0	0.0	0.0	0.0	0.0	0.0	1,047.0	0.0	226.5	0.0	0.0	10,601.0
	Upgrade	0.0	0.0	0.0	5.0	0.0	0.0	213.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20.5	0.0	0.0	0.0	0.0	238.7
Under Construction	New Generation	0.0	0.0	0.0	0.0	0.0	0.0	200.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	200.0
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Suspended	New Generation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Withdrawn	New Generation	4,943.6	24,103.4	0.0	3,552.2	1,814.0	0.0	25,593.9	2,128.0	0.0	0.0	4,988.4	3,240.8	150.3	7,397.0	0.0	0.0	0.0	5,257.0	0.0	3,835.2	20.0	0.0	87,023.6
	Upgrade	5.0	370.0	0.0	119.4	0.0	0.0	755.7	0.0	0.0	0.0	114.0	30.0	0.0	0.0	0.0	0.0	0.0	243.4	0.0	6.0	0.0	0.0	1,643.4
Active	New Generation	3,141.6	3,346.3	0.0	821.5	297.7	0.0	8,920.7	0.0	0.0	0.0	5,307.5	6,414.2	0.0	10,579.2	0.0	0.0	0.0	236.9	0.0	174.8	2,610.0	0.0	41,850.3
	Upgrade	0.0	16.6	0.0	207.6	0.0	0.0	483.4	0.0	0.0	0.0	0.0	955.3	0.0	2,330.0	0.0	0.0	0.0	350.2	0.0	0.0	0.0	0.0	4,343.0
Total Projects	New Generation	8,092.7	30,994.3	0.0	5,737.7	2,111.7	0.0	38,803.5	2,128.0	0.0	0.0	10,618.4	9,655.0	150.3	17,976.2	0.0	0.0	0.0	6,540.8	0.0	4,236.5	2,630.0	0.0	139,674.9
	Upgrade	5.0	386.6	0.0	332.0	0.0	0.0	1,452.2	0.0	0.0	0.0	114.0	985.3	0.0	2,330.0	0.0	0.0	0.0	614.0	0.0	6.0	0.0	0.0	6,225.2

Solar Project Analysis

Table 12-41 shows the status of all solar generation projects by number of projects that entered PJM generation queues from January 1, 1997, through December 31, 2022, by zone. Of the 1,808 solar projects classified as new generation or upgrade currently active, suspended or under construction in the PJM generation queue, 394 projects (21.8 percent) are located in the DOM Zone.

Table 12-41 Status of all solar generation queue projects by zone (number of projects): January 1, 1997 through December 31, 2022

		Number of Projects																						
Project Status	Project Classification	ACEC	AEP	AMPT	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
In Service	New Generation	10	11	0	10	0	1	1	1	1	0	52	13	1	53	0	0	1	1	1	2	46	0	205
	Upgrade	2	3	0	3	0	0	0	0	2	0	11	10	0	11	0	0	0	1	0	3	0	0	46
Under Construction	New Generation	1	4	0	3	2	0	1	1	0	3	19	6	0	1	3	0	0	3	1	0	3	0	51
	Upgrade	0	2	0	0	1	0	1	0	0	1	3	0	0	0	0	0	0	0	0	0	4	0	12
Suspended	New Generation	0	2	0	10	4	0	2	1	0	0	14	1	1	0	4	0	0	4	0	3	0	0	46
	Upgrade	0	0	0	1	0	0	0	0	0	0	2	0	0	1	0	0	0	0	0	0	0	0	4
Withdrawn	New Generation	192	135	0	102	36	15	47	27	16	2	258	157	16	198	29	1	10	78	25	61	121	0	1,526
	Upgrade	4	6	0	4	5	0	6	1	0	0	24	3	0	9	3	0	0	10	3	0	3	0	81
Active	New Generation	22	285	1	132	84	5	78	33	10	3	309	56	64	32	37	2	11	167	9	79	4	0	1,423
	Upgrade	2	72	1	23	20	0	17	12	2	0	47	11	6	2	10	2	0	23	0	22	0	0	272
Total Projects	New Generation	225	437	1	257	126	21	129	63	27	8	652	233	82	284	73	3	22	253	36	145	174	0	3,251
	Upgrade	8	83	1	31	26	0	24	13	4	1	87	24	6	23	13	2	0	34	3	25	7	0	415

Table 12-42 shows the status of all solar projects by MW that entered PJM generation queues from January 1, 1997, through December 31, 2022, by zone. Of the 128,320.3 MW of solar projects classified as new generation or upgrade currently active, suspended or under construction in the PJM generation queue, 43,523.5 MW (33.9 percent) are located in the AEP Zone.

Table 12-42 Status of all solar generation queue projects by zone (MW): January 1, 1997 through December 31, 2022

		Project MW																						
Project Status	Project Classification	ACEC	AEP	AMPT	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
In Service	New Generation	65.0	567.2	0.0	140.5	0.0	1.1	9.0	2.5	125.0	0.0	2,957.2	151.3	50.0	397.9	0.0	0.0	3.3	13.5	2.5	15.0	241.9	0.0	4,742.8
	Upgrade	0.0	170.0	0.0	0.0	0.0	0.0	0.0	0.0	75.0	0.0	86.1	0.0	0.0	14.3	0.0	0.0	0.0	0.0	0.0	10.0	0.0	0.0	355.4
Under Construction	New Generation	2.6	376.8	0.0	93.8	356.0	0.0	50.0	400.0	0.0	45.9	1,201.6	279.6	0.0	19.8	60.0	0.0	0.0	140.0	27.5	0.0	17.5	0.0	3,071.1
	Upgrade	0.0	147.0	0.0	0.0	20.0	0.0	50.0	0.0	0.0	8.3	12.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.8	0.0	241.1
Suspended	New Generation	0.0	97.9	0.0	275.6	395.0	0.0	32.5	178.0	0.0	0.0	1,094.8	92.0	95.0	0.0	12.0	0.0	0.0	60.2	0.0	42.8	0.0	0.0	2,375.7
	Upgrade	0.0	0.0	0.0	15.9	0.0	0.0	0.0	0.0	0.0	0.0	70.0	0.0	0.0	11.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	96.9
Withdrawn	New Generation	2,120.2	9,390.4	0.0	2,907.2	1,923.7	121.6	3,406.2	2,324.6	689.4	33.0	16,015.8	2,681.6	998.9	1,623.6	1,011.7	78.0	98.2	2,630.6	440.0	1,070.1	570.3	0.0	50,134.8
	Upgrade	172.5	126.0	0.0	32.9	213.0	0.0	110.0	20.0	0.0	0.0	1,113.6	5.0	0.0	23.8	15.0	0.0	0.0	53.7	3.6	0.0	1.3	0.0	1,890.3
Active	New Generation	617.7	38,748.6	40.0	5,606.9	5,376.3	154.9	12,254.4	2,754.9	648.9	34.7	27,479.3	1,934.1	6,007.2	669.0	596.4	340.0	145.4	5,495.4	210.7	2,318.8	37.9	0.0	111,471.4
	Upgrade	48.0	4,153.2	166.0	554.4	730.7	0.0	1,707.0	225.5	30.0	0.0	1,974.6	74.0	253.8	16.4	193.0	90.0	0.0	525.5	0.0	322.1	0.0	0.0	11,064.1
Total Projects	New Generation	2,805.5	49,180.9	40.0	9,023.8	8,051.0	277.6	15,752.1	5,659.9	1,463.3	113.6	48,748.6	5,138.6	7,151.1	2,710.2	1,680.1	418.0	246.9	8,339.6	680.7	3,446.7	867.6	0.0	171,795.8
	Upgrade	220.5	4,596.2	166.0	603.1	963.7	0.0	1,867.0	245.5	105.0	8.3	3,256.3	78.9	253.8	65.5	208.0	90.0	0.0	579.2	3.6	332.1	5.1	0.0	13,647.8

Battery Project Analysis

Table 12-43 shows the status of all battery generation projects by number of projects that entered PJM generation queues from January 1, 1997, through December 31, 2022, by zone. Of the 672 battery projects currently active, suspended or under construction in the PJM generation queue, 227 projects (33.8 percent) are located in the DOM Zone.

Table 12-43 Status of all battery generation queue projects by zone (number of projects): January 1, 1997 through December 31, 2022

		Number of Projects																						
Project Status	Project Classification	ACEC	AEP	AMPT	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	2	0	3	0	0	8	1	4	0	0	0	0	2	0	0	1	0	0	1	2	0	24
	Upgrade	0	1	0	0	0	0	0	1	1	0	0	0	0	2	0	0	0	2	0	0	0	0	7
Under Construction	New Generation	0	0	0	0	0	0	0	0	0	0	1	0	0	2	0	0	0	0	0	0	0	0	3
	Upgrade	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Suspended	New Generation	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	1	2	0	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
Withdrawn	New Generation	7	33	0	4	7	25	27	3	3	1	33	17	1	36	4	0	4	4	1	7	4	0	221
	Upgrade	4	8	0	7	2	0	5	2	1	0	10	2	0	6	2	0	3	7	0	1	0	0	60
Active	New Generation	15	75	0	20	14	11	42	1	3	5	145	16	5	19	6	0	0	10	6	7	12	0	412
	Upgrade	6	47	1	18	10	1	41	5	1	0	81	7	3	5	5	0	0	17	0	4	1	0	253
Total Projects	New Generation	22	110	0	27	21	36	77	5	10	6	179	33	6	60	10	0	5	14	7	16	20	0	664
	Upgrade	10	56	1	25	12	1	46	8	3	0	91	9	3	13	7	0	3	26	0	5	1	0	320

Table 12-44 shows the status of all battery projects by MW that entered PJM generation queues from January 1, 1997, through December 31, 2022, by zone. Of the 52,926.0 MW of battery generation currently active, suspended or under construction in the PJM generation queue, 15,303.2 MW (28.9 percent) are located in the DOM Zone.

Table 12-44 Status of all battery generation queue projects by zone (MW): January 1, 1997 through December 31, 2022

		Project MW																						
Project Status	Project Classification	ACEC	AEP	AMPT	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	6.0	0.0	39.9	0.0	0.0	87.0	12.0	16.0	0.0	0.0	0.0	0.0	40.0	0.0	0.0	1.0	0.0	0.0	20.0	3.0	0.0	224.9
	Upgrade	0.0	4.0	0.0	0.0	0.0	0.0	0.0	8.0	4.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	28.4	0.0	0.0	0.0	0.0	44.4
Under Construction	New Generation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20.0	0.0	0.0	14.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	34.0
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Suspended	New Generation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.0	0.0	0.0	0.0	0.0	0.0	20.0	7.0	0.0	29.0
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Withdrawn	New Generation	161.0	1,419.0	0.0	187.0	206.1	260.6	1,679.0	319.9	75.5	20.0	1,973.4	350.0	20.3	804.1	214.7	0.0	4.3	360.0	20.0	299.8	9.5	0.0	8,384.2
	Upgrade	20.0	302.2	0.0	189.0	20.3	0.0	325.0	95.0	20.0	0.0	183.0	14.0	0.0	55.1	30.0	0.0	60.0	41.0	0.0	20.0	0.0	0.0	1,374.6
Active	New Generation	1,739.5	8,631.5	0.0	1,927.5	2,010.0	1,342.5	5,984.8	85.0	475.0	505.0	13,374.2	909.0	176.0	1,046.8	526.2	0.0	0.0	905.8	796.0	445.0	1,760.0	0.0	42,639.8
	Upgrade	0.0	2,594.4	0.0	1,573.3	408.0	115.0	2,311.3	255.0	52.2	0.0	1,909.0	155.0	0.0	24.0	429.0	0.0	0.0	362.0	0.0	20.0	15.0	0.0	10,223.2
Total Projects	New Generation	1,900.5	10,056.5	0.0	2,154.4	2,216.1	1,603.1	7,750.8	416.9	566.5	525.0	15,367.6	1,259.0	196.3	1,906.9	740.9	0.0	5.3	1,265.8	816.0	784.8	1,779.5	0.0	51,311.9
	Upgrade	20.0	2,900.6	0.0	1,762.3	428.3	115.0	2,636.3	358.0	76.2	0.0	2,092.0	169.0	0.0	79.1	459.0	0.0	60.0	431.4	0.0	40.0	15.0	0.0	11,642.2

Renewable Hybrid Project Analysis

Table 12-45 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, 2022, by zone.[58] Of the 452 renewable hybrid projects currently active, suspended or under construction in the PJM generation queue, 113 projects (25.0 percent) are located in the AEP Zone.

Table 12-45 Status of all renewable hybrid generation queue projects by zone (number of projects): January 1, 1997 through December 31, 2022

		Number of Projects																						
Project Status	Project Classification	ACEC	AEP	AMPT	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	1	0	1
	Upgrade	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Under Construction	New Generation	0	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	0	1
Suspended	New Generation	0	0	0	7	0	0	0	0	0	0	0	0	0	0	7	0	0	1	0	1	0	0	16
	Upgrade	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	1
Withdrawn	New Generation	4	11	0	8	5	0	6	0	0	0	30	2	8	1	1	0	0	4	1	6	10	0	97
	Upgrade	0	0	0	0	0	0	0	0	0	0	1	0	0	0	1	0	0	0	0	0	0	0	2
Active	New Generation	5	104	0	29	12	0	21	12	2	3	74	4	34	6	16	1	1	23	3	37	1	0	388
	Upgrade	1	8	0	4	3	0	2	3	0	0	7	0	4	0	1	0	0	5	0	6	0	0	44
Total Projects	New Generation	9	115	0	44	17	0	27	12	2	3	104	6	42	7	24	1	1	28	4	44	14	0	504
	Upgrade	1	9	0	5	3	0	2	3	0	0	8	0	4	0	2	0	0	5	0	7	0	0	49

Table 12-46 shows the status of all renewable hybrid projects by MW that entered PJM generation queues from January 1, 1997, through December 31, 2022, by zone. Of the 40,628.0 MW of renewable hybrid generation currently active, suspended or under construction in the PJM generation queue, 15,918.3 MW (39.2 percent) are located in the AEP Zone.

Table 12-46 Status of all renewable hybrid generation queue projects by zone (MW): January 1, 1997 through December 31, 2022

		Project MW																						
Project Status	Project Classification	ACEC	AEP	AMPT	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	0.0	1.1	0.0	1.1
	Upgrade	0.0	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
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	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	0.0	3.2
Suspended	New Generation	0.0	0.0	0.0	32.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	18.9	0.0	0.0	3.0	0.0	90.0	0.0	0.0	144.4
	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	0.0	0.0	0.0	0.0	0.0	0.0	50.0	0.0	0.0	50.0
Withdrawn	New Generation	14.5	3,460.8	0.0	568.0	334.9	0.0	986.9	0.0	0.0	0.0	2,289.9	104.5	1,004.0	20.0	20.0	0.0	0.0	184.2	20.0	201.0	36.1	0.0	9,244.8
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	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	161.0	15,250.1	0.0	3,214.7	831.5	0.0	3,178.5	610.8	50.0	107.5	8,058.2	270.0	3,049.1	215.0	263.3	178.5	5.0	1,488.4	1,452.0	489.0	20.0	0.0	38,892.6
	Upgrade	60.0	665.0	0.0	0.0	60.1	0.0	20.0	40.0	0.0	0.0	199.0	0.0	165.0	0.0	0.0	0.0	0.0	115.2	0.0	211.0	0.0	0.0	1,535.3
Total Projects	New Generation	175.5	18,710.9	0.0	3,815.3	1,166.4	0.0	4,165.4	610.8	50.0	107.5	10,348.1	374.5	4,053.1	235.0	302.2	178.5	5.0	1,675.7	1,472.0	780.0	59.7	0.0	48,285.4
	Upgrade	60.0	668.2	0.0	16.3	60.1	0.0	20.0	40.0	0.0	0.0	199.0	0.0	165.0	0.0	3.7	0.0	0.0	115.2	0.0	261.0	0.0	0.0	1,608.5

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.”[59] 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 12-47 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, 2022, by transmission owner and unit type. A project where the developer is affiliated with the transmission owner is classified as related. A

58 PJM does not currently have a definition of a hybrid resource.
59 See OATT § 1 (Transmission Owner).

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 818,390.6 MW that have entered the queue during the time period of January 1, 1997, through December 31, 2022, 71,857.3 MW (8.8 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 40,286.7 MW that entered the queue in the PSEG Zone during the time period of January 1, 1997, through December 31, 2022, 14,282.3 MW (35.5 percent) were submitted by PSEG or one of their affiliated companies.

Table 12-47 Relationship between project developer and transmission owner for all interconnection queue projects MW by unit type: December 31, 2022

				MW by Unit Type																						
Parent Company	Transmission Owner	Related to Developer	Number of Projects	Battery	CC	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total	Percent of Total
AEP	AEP	Related	52	116.0	678.0	0.0	0.0	0.0	0.0	34.0	2.4	214.0	0.0	0.0	0.0	299.7	180.0	0.0	3,918.0	90.0	0.0	0.0	0.0	0.0	5,532.1	3.5%
		Unrelated	1,114	12,841.1	21,973.5	2,594.1	7.5	506.5	0.0	0.0	453.6	0.0	12.0	0.0	75.4	53,477.4	19,199.1	0.0	10,399.0	0.0	0.0	452.0	31,380.9	0.0	153,372.0	96.5%
AES	DAY	Related	14	20.0	0.0	47.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	21.5	0.0	0.0	1,347.5	0.0	0.0	0.0	0.0	0.0	1,436.0	11.7%
		Unrelated	125	754.9	1,150.0	264.5	0.0	12.0	0.0	0.0	0.0	0.0	0.0	0.0	10.0	5,883.9	650.8	0.0	0.0	0.0	0.0	0.0	2,128.0	0.0	10,854.1	88.3%
AMP	AMPT	Related	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	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	206.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	206.0	100.0%
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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	48	525.0	665.0	237.9	40.0	19.2	0.0	0.0	194.6	1,879.0	0.0	0.0	0.0	121.9	107.5	0.0	2,810.0	0.0	0.0	20.0	0.0	0.0	6,620.1	100.0%
DOM	DOM	Related	201	1,171.7	11,378.5	2,045.7	100.0	0.0	0.0	340.0	0.0	1,944.0	0.0	0.0	60.0	6,347.0	17.0	0.0	301.0	0.0	0.0	4.0	2,786.0	0.0	26,494.9	22.2%
		Unrelated	1,123	16,287.9	9,268.5	2,225.8	0.5	227.3	0.0	0.0	35.0	0.0	0.0	10.0	119.4	45,658.0	10,380.1	0.0	20.0	0.0	0.0	316.3	7,946.4	150.0	92,645.2	77.8%
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	105.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	178.7	5.6%
		Unrelated	43	605.4	667.5	0.0	0.0	0.0	0.0	0.0	112.0	0.0	0.0	0.0	4.8	1,462.9	40.0	10.0	120.0	0.0	0.0	0.0	0.0	0.0	3,022.6	94.4%
EKPC	EKPC	Related	2	0.0	821.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	821.8	6.3%
		Unrelated	146	196.3	170.0	73.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7,404.9	4,218.1	0.0	0.0	0.0	0.0	0.0	150.3	0.0	12,212.5	93.7%
Exelon	ACEC	Related	4	0.0	530.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	538.3	2.2%
		Unrelated	382	1,920.5	9,048.4	807.4	388.0	20.7	2.8	0.0	0.0	0.0	2.0	5.0	10.3	3,017.7	235.5	0.0	15.0	5.5	0.0	10.0	8,097.7	0.0	23,586.5	97.8%
	BGE	Related	15	22.5	250.0	10.0	0.0	0.0	0.0	0.0	0.0	117.2	0.0	0.0	8.5	20.0	0.0	0.0	10.0	101.0	0.0	0.0	0.0	0.0	539.2	5.9%
		Unrelated	77	1,695.6	3,012.1	166.6	18.0	133.0	0.0	0.0	0.4	3,280.0	1.3	0.0	0.0	257.6	0.0	0.0	0.0	2.5	0.0	25.0	0.0	0.0	8,592.1	94.1%
	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	9.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,490.0	1.6%
		Unrelated	598	10,387.1	16,823.2	1,529.2	42.0	65.2	5.0	0.0	22.7	0.0	35.0	0.0	67.7	17,610.1	3,986.4	199.0	1,926.0	91.0	0.0	90.0	40,255.7	0.0	93,135.3	98.4%
	DPL	Related	5	1.0	60.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	68.4	0.3%
		Unrelated	412	1,427.0	6,916.6	1,226.0	600.9	40.5	0.0	0.0	0.0	0.0	0.0	0.0	84.6	5,210.2	374.5	0.0	653.0	15.0	0.0	65.0	10,640.3	0.0	27,253.5	99.7%
	PECO	Related	33	40.0	7,515.0	5.0	83.0	0.0	0.0	0.0	265.0	437.8	0.0	0.0	0.0	0.0	0.0	0.0	7.0	0.0	0.0	0.0	0.0	0.0	8,352.8	28.0%
		Unrelated	98	25.3	20,610.5	596.5	8.5	15.0	0.0	0.0	0.0	0.0	0.0	17.0	3.7	246.9	5.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	21,528.4	72.0%
	PEPCO	Related	5	1.0	503.0	0.0	0.0	4.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	508.0	1.7%
		Unrelated	119	815.0	23,827.9	92.3	34.0	5.0	0.0	0.0	0.0	1,640.0	32.0	0.0	3.5	684.3	1,472.0	0.0	0.0	6.0	0.0	0.0	0.0	0.0	28,612.0	98.3%
First Energy	APS	Related	10	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	71.2	0.0	0.0	1,710.0	0.0	0.0	0.0	0.0	0.0	3,234.2	5.2%
		Unrelated	638	3,916.7	29,272.8	1,479.7	0.0	84.4	0.0	0.0	638.3	0.0	154.4	53.8	25.4	9,555.8	3,815.3	0.0	4,092.0	0.0	0.0	184.4	6,069.7	16.3	59,358.9	94.8%
	ATSI	Related	6	0.0	1,678.0	0.0	0.0	0.0	0.0	0.0	0.0	16.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,694.0	5.4%
		Unrelated	269	2,644.4	13,647.0	588.7	10.5	166.4	0.0	0.0	0.0	0.0	59.7	6.6	6.9	9,014.7	1,226.5	0.0	0.0	16.5	0.0	0.0	2,111.7	0.0	29,499.6	94.6%
	JCPLC	Related	2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20.0	0.0	0.0	0.0	0.0	12.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	32.0	0.1%
		Unrelated	472	1,986.0	15,751.4	542.1	0.0	4.8	0.6	30.0	1.6	0.0	0.6	0.0	12.8	2,763.7	235.0	0.0	0.0	0.0	0.0	30.0	20,306.2	0.0	41,664.8	99.9%
	MEC	Related	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	212	1,199.9	17,488.9	57.6	1,204.4	52.1	0.0	0.0	0.0	93.0	0.0	8.0	23.2	1,888.1	305.9	0.0	0.0	0.0	0.0	84.0	0.0	0.0	22,405.1	100.0%
	PE	Related	4	0.0	534.0	5.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,860.0	0.0	0.0	0.0	0.0	0.0	2,399.0	5.4%
		Unrelated	590	1,697.2	18,717.9	1,532.2	0.0	218.0	3.0	16.0	46.3	0.0	341.8	8.0	14.8	8,918.7	1,790.9	0.0	561.0	590.0	0.0	525.0	7,154.8	0.0	42,135.4	94.6%
OVEC	OVEC	Related	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	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	508.0	178.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	686.5	100.0%
PPL	PPL	Related	24	0.0	2,261.0	0.0	0.0	0.0	0.0	0.0	109.0	1,650.0	0.0	0.0	0.0	124.8	0.0	0.0	111.0	0.0	0.0	0.0	0.0	0.0	4,255.8	9.0%
		Unrelated	433	824.8	23,928.3	423.1	8.0	234.5	0.0	1,200.0	142.6	438.0	19.9	2.4	44.7	3,654.1	951.0	0.0	6,896.6	0.0	0.0	31.0	4,242.5	90.0	43,131.5	91.0%
PSEG	PSEG	Related	108	0.0	11,836.1	1,818.1	0.0	0.0	0.0	0.0	0.0	381.0	0.0	0.0	0.0	175.4	3.7	0.0	24.0	44.0	0.0	0.0	0.0	0.0	14,282.3	35.5%
		Unrelated	278	1,794.5	17,971.9	1,137.9	600.0	62.5	4.9	0.0	1,000.0	0.0	10.6	0.0	13.7	697.3	56.1	0.0	0.0	25.0	0.0	0.0	2,630.0	0.0	26,004.4	64.5%
Con Ed	REC	Related	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	2	0.0	6.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6.9	100.0%
Total		Related	514	1,409.5	39,534.4	4,226.8	183.0	4.0	0.0	374.0	396.4	5,945.0	0.0	0.0	68.5	7,201.5	200.7	0.0	9,288.5	235.0	0.0	4.0	2,786.0	0.0	71,857.3	8.8%
		Unrelated	7,188	61,544.7	250,918.1	15,574.6	2,962.3	1,867.1	16.3	1,246.0	2,647.0	7,330.0	669.3	110.8	520.9	178,242.1	49,227.9	209.0	27,492.6	751.5	0.0	1,832.7	143,114.1	256.3	746,533.3	91.2%

Combined Cycle Project Developer and Transmission Owner Relationships

Table 12-48 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, 2022, by transmission owner and project status. Of the 47,662.1 combined cycle project MW that are in service or currently under construction, 8,814.6 MW (18.5 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, 2022, 821.8 MW (82.9 percent) have been submitted by EKPC or one of their affiliated companies.

Table 12-48 Relationship between project developer and transmission owner for all combined cycle project MW in the queue: December 31, 2022

			MW by Project Status						
Parent Company	Transmission Owner	Related to Developer	Active	In Service	Under Construction	Suspended	Withdrawn	Total	Percent of Total
AEP	AEP	Related	0.0	678.0	0.0	0.0	0.0	678.0	3.0%
		Unrelated	285.0	4,308.0	1,925.0	1,150.0	14,305.5	21,973.5	97.0%
AES	DAY	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	0.0	0.0	0.0	0.0	1,150.0	1,150.0	100.0%
AMP	AMPT	Related	0.0	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	0.0%
DUQ	DUQ	Related	0.0	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	100.0%
DOM	DOM	Related	75.0	4,762.5	0.0	0.0	6,541.0	11,378.5	55.1%
		Unrelated	24.0	2,044.1	0.0	0.0	7,200.4	9,268.5	44.9%
DUKE	DUKE	Related	0.0	0.0	0.0	0.0	36.0	36.0	5.1%
		Unrelated	0.0	533.0	0.0	0.0	134.5	667.5	94.9%
EKPC	EKPC	Related	0.0	0.0	0.0	0.0	821.8	821.8	82.9%
		Unrelated	0.0	0.0	0.0	0.0	170.0	170.0	17.1%
Exelon	ACEC	Related	0.0	0.0	0.0	0.0	530.0	530.0	5.8%
		Unrelated	0.0	879.0	0.0	0.0	7,719.4	8,598.4	94.2%
	BGE	Related	0.0	130.0	0.0	0.0	120.0	250.0	7.7%
		Unrelated	0.0	10.0	0.0	0.0	3,002.1	3,012.1	92.3%
	COMED	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	111.7	2,434.5	1,150.0	575.0	12,552.0	16,823.2	100.0%
	DPL	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	451.0	361.2	0.0	0.0	6,104.4	6,916.6	100.0%
	PECO	Related	0.0	0.0	0.0	0.0	6,415.0	6,415.0	25.0%
		Unrelated	5.0	3,740.5	0.0	0.0	15,515.0	19,260.5	75.0%
	PEPCO	Related	0.0	80.0	0.0	0.0	423.0	503.0	2.2%
		Unrelated	45.0	1,708.6	0.0	0.0	20,469.3	22,222.9	97.8%
First Energy	APS	Related	0.0	525.0	0.0	0.0	928.0	1,453.0	4.7%
		Unrelated	4,640.0	2,384.7	20.0	0.0	22,188.1	29,232.8	95.3%
	ATSI	Related	0.0	0.0	0.0	0.0	1,678.0	1,678.0	10.9%
		Unrelated	998.0	4,095.0	0.0	955.0	7,599.0	13,647.0	89.1%
	JCPLC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	0.0	1,775.8	0.0	0.0	13,241.6	15,017.4	100.0%
	MEC	Related	0.0	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	100.0%
	PE	Related	0.0	0.0	0.0	0.0	534.0	534.0	2.8%
		Unrelated	0.0	2,042.3	0.0	85.0	16,620.6	18,747.9	97.2%
OVEC	OVEC	Related	0.0	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	0.0%
PPL	PPL	Related	0.0	600.0	0.0	0.0	1,661.0	2,261.0	8.6%
		Unrelated	55.0	5,862.0	51.6	0.0	17,959.7	23,928.3	91.4%
PSEG	PSEG	Related	0.0	1,988.0	51.1	0.0	9,297.0	11,336.1	38.7%
		Unrelated	0.0	806.4	0.0	0.0	17,165.5	17,971.9	61.3%
Con Ed	REC	Related	0.0	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	100.0%
Total		Related	75.0	8,763.5	51.1	0.0	28,984.8	37,874.4	13.3%
		Unrelated	6,614.7	35,625.9	3,221.6	2,765.0	198,511.8	246,739.1	86.7%

Combustion Turbine – Natural Gas Project Developer and Transmission Owner Relationships

Table 12-49 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, 2022, by transmission owner and project status. Of the 9,828.8 CT – natural gas project MW that are in service or currently under construction, 1,803.0 (18.3 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, 2022, 1,818.1 MW (61.5 percent) have been submitted by PSEG or one of their affiliated companies.

Table 12-49 Relationship between project developer and transmission owner for all CT – natural gas project MW in the queue: December 31, 2022

			MW by Project Status						
Parent Company	Transmission Owner	Related to Developer	Active	In Service	Under Construction	Suspended	Withdrawn	Total	Percent of Total
AEP	AEP	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	842.1	227.0	0.0	0.0	1,525.0	2,594.1	100.0%
AES	DAY	Related	0.0	47.0	0.0	0.0	0.0	47.0	15.1%
		Unrelated	20.0	36.5	0.0	0.0	208.0	264.5	84.9%
AMP	AMPT	Related	0.0	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	0.0%
DUQ	DUQ	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	0.0	219.4	0.0	0.0	18.5	237.9	100.0%
DOM	DOM	Related	1,138.0	824.0	0.0	0.0	83.7	2,045.7	47.9%
		Unrelated	0.0	1,182.7	0.0	0.0	1,043.1	2,225.8	52.1%
DUKE	DUKE	Related	0.0	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	0.0%
EKPC	EKPC	Related	0.0	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	100.0%
Exelon	ACEC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	0.0	404.4	0.0	230.0	173.0	807.4	100.0%
	BGE	Related	0.0	10.0	0.0	0.0	0.0	10.0	5.7%
		Unrelated	0.0	13.0	0.0	0.0	153.6	166.6	94.3%
	COMED	Related	296.0	0.0	0.0	0.0	0.0	296.0	16.2%
		Unrelated	258.2	478.0	410.0	0.0	383.0	1,529.2	83.8%
	DPL	Related	0.0	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	100.0%
	PECO	Related	0.0	5.0	0.0	0.0	0.0	5.0	0.8%
		Unrelated	0.0	596.0	0.0	0.0	0.5	596.5	99.2%
	PEPCO	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	42.3	37.0	0.0	0.0	13.0	92.3	100.0%
First Energy	APS	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	30.0	1,445.7	0.0	0.0	4.0	1,479.7	100.0%
	ATSI	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	458.7	100.0	5.0	0.0	25.0	588.7	100.0%
	JCPLC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	0.0	540.0	0.0	0.0	2.1	542.1	100.0%
	MEC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	0.0	46.1	11.5	0.0	0.0	57.6	100.0%
	PE	Related	0.0	5.0	0.0	0.0	0.0	5.0	0.3%
		Unrelated	555.0	384.9	30.5	0.0	561.8	1,532.2	99.7%
OVEC	OVEC	Related	0.0	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	0.0%
PPL	PPL	Related	0.0	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	100.0%
PSEG	PSEG	Related	0.0	912.0	0.0	0.0	906.1	1,818.1	61.5%
		Unrelated	0.0	228.9	0.0	675.0	234.0	1,137.9	38.5%
Con Ed	REC	Related	0.0	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	0.0%
Total		Related	1,434.0	1,803.0	0.0	0.0	989.8	4,226.8	21.3%
		Unrelated	2,206.3	7,568.8	457.0	905.0	4,437.5	15,574.6	78.7%

Wind Project Developer and Transmission Owner Relationships

Table 12-50 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, 2022, by transmission owner and project status. Of the 11,039.7 wind project MW that are in service or currently under construction, 12.0 MW (0.1 percent) have been developed by transmission owners building in their own service territory. DOM is the transmission owner with the highest percentage of affiliates building wind projects in their own service territory. Of the 10,732.4 MW that entered the queue in the DOM Zone during the time period of January 1, 1997, through December 31, 2022, 2,786.0 MW (26.0 percent) have been submitted by DOM or one of their affiliated companies.

Table 12-50 Relationship between project developer and transmission owner for all wind project MW in the queue: December 31, 2022

			MW by Project Status						
Parent Company	Transmission Owner	Related to Developer	Active	In Service	Under Construction	Suspended	Withdrawn	Total	Percent of Total
AEP	AEP	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	3,363.0	3,544.6	0.0	0.0	24,473.4	31,380.9	100.0%
AES	DAY	Related	0.0	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	100.0%
AMP	AMPT	Related	0.0	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	0.0%
DUQ	DUQ	Related	0.0	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	0.0%
DOM	DOM	Related	2,640.0	12.0	0.0	0.0	134.0	2,786.0	26.0%
		Unrelated	2,667.5	310.5	0.0	0.0	4,968.4	7,946.4	74.0%
DUKE	DUKE	Related	0.0	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	0.0%
EKPC	EKPC	Related	0.0	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	100.0%
Exelon	ACEC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	3,141.6	7.5	0.0	0.0	4,948.6	8,097.7	100.0%
	BGE	Related	0.0	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	0.0%
	COMED	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	9,404.1	4,302.1	200.0	0.0	26,349.5	40,255.7	100.0%
	DPL	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	7,369.5	0.0	0.0	0.0	3,270.8	10,640.3	100.0%
	PECO	Related	0.0	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	0.0%
	PEPCO	Related	0.0	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	0.0%
First Energy	APS	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	1,029.1	1,369.0	0.0	0.0	3,671.6	6,069.7	100.0%
	ATSI	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	297.7	0.0	0.0	0.0	1,814.0	2,111.7	100.0%
	JCPLC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	12,909.2	0.0	0.0	0.0	7,397.0	20,306.2	100.0%
	MEC	Related	0.0	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	0.0%
	PE	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	587.0	1,067.5	0.0	0.0	5,500.3	7,154.8	100.0%
OVEC	OVEC	Related	0.0	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	0.0%
PPL	PPL	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	174.8	226.5	0.0	0.0	3,841.2	4,242.5	100.0%
PSEG	PSEG	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	2,610.0	0.0	0.0	0.0	20.0	2,630.0	100.0%
Con Ed	REC	Related	0.0	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	0.0%
Total		Related	2,640.0	12.0	0.0	0.0	134.0	2,786.0	1.9%
		Unrelated	43,553.4	10,827.7	200.0	0.0	88,533.0	143,114.1	98.1%

Solar Project Developer and Transmission Owner Relationships

Table 12-51 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, 2022, by transmission owner and project status. Of the 8,410.4 solar project MW that are in service or currently under construction, 1,585.8 MW (18.9 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 solar projects in their own service territory. Of the 872.7 MW that entered the queue in the PSEG Zone during the time period of January 1, 1997, through December 31, 2022, 175.4 MW (20.1 percent) have been submitted by PSEG or one of their affiliated companies.

Table 12-51 Relationship between project developer and transmission owner for all solar project MW in the queue: December 31, 2022

			MW by Project Status						
Parent Company	Transmission Owner	Related to Developer	Active	In Service	Under Construction	Suspended	Withdrawn	Total	Percent of Total
AEP	AEP	Related	100.0	34.7	0.0	0.0	165.0	299.7	0.6%
		Unrelated	42,801.8	702.5	523.8	97.9	9,351.4	53,477.4	99.4%
AES	DAY	Related	0.0	0.0	0.0	0.0	21.5	21.5	0.4%
		Unrelated	2,980.4	2.5	400.0	178.0	2,323.1	5,883.9	99.6%
AMP	AMPT	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	206.0	0.0	0.0	0.0	0.0	206.0	100.0%
DUQ	DUQ	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	34.7	0.0	54.2	0.0	33.0	121.9	100.0%
DOM	DOM	Related	4,595.0	1,278.2	122.0	99.9	251.9	6,347.0	12.2%
		Unrelated	24,858.9	1,765.1	1,091.6	1,064.9	16,877.5	45,658.0	87.8%
DUKE	DUKE	Related	49.0	0.0	0.0	0.0	56.4	105.4	6.7%
		Unrelated	629.9	200.0	0.0	0.0	633.0	1,462.9	93.3%
EKPC	EKPC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	6,261.0	50.0	0.0	95.0	998.9	7,404.9	100.0%
Exelon	ACEC	Related	0.0	0.0	0.0	0.0	8.3	8.3	0.3%
		Unrelated	665.7	65.0	2.6	0.0	2,284.4	3,017.7	99.7%
	BGE	Related	0.0	0.0	0.0	0.0	20.0	20.0	7.2%
		Unrelated	154.9	1.1	0.0	0.0	101.6	257.6	92.8%
	COMED	Related	0.0	9.0	0.0	0.0	0.0	9.0	0.1%
		Unrelated	13,961.4	0.0	100.0	32.5	3,516.2	17,610.1	99.9%
	DPL	Related	0.0	7.4	0.0	0.0	0.0	7.4	0.1%
		Unrelated	2,008.1	144.0	279.6	92.0	2,686.5	5,210.2	99.9%
	PECO	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	145.4	3.3	0.0	0.0	98.2	246.9	100.0%
	PEPCO	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	210.7	2.5	27.5	0.0	443.6	684.3	100.0%
First Energy	APS	Related	71.2	0.0	0.0	0.0	0.0	71.2	0.7%
		Unrelated	6,090.0	140.5	93.8	291.5	2,940.0	9,555.8	99.3%
	ATSI	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	6,107.0	0.0	376.0	395.0	2,136.7	9,014.7	100.0%
	JCPLC	Related	0.0	0.0	0.0	0.0	12.0	12.0	0.4%
		Unrelated	685.4	412.2	19.8	11.0	1,635.4	2,763.7	99.6%
	MEC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	789.4	0.0	60.0	12.0	1,026.7	1,888.1	100.0%
	PE	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	6,020.8	13.5	140.0	60.2	2,684.2	8,918.7	100.0%
OVEC	OVEC	Related	0.0	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	100.0%
PPL	PPL	Related	124.8	0.0	0.0	0.0	0.0	124.8	3.3%
		Unrelated	2,516.2	25.0	0.0	42.8	1,070.1	3,654.1	96.7%
PSEG	PSEG	Related	0.0	129.3	5.2	0.0	40.9	175.4	20.1%
		Unrelated	37.9	112.6	16.1	0.0	530.7	697.3	79.9%
Con Ed	REC	Related	0.0	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	0.0%
Total		Related	4,939.9	1,458.6	127.2	99.9	576.0	7,201.5	3.9%
		Unrelated	117,595.6	3,639.7	3,185.0	2,372.7	51,449.1	178,242.1	96.1%

Battery Project Developer and Transmission Owner Relationships

Table 12-52 shows the relationship between the project developer and transmission owner for all battery project MW that have entered the PJM generation queue from January 1, 1997, through December 31, 2022, by transmission owner and project status. Of the 303.3 battery project MW that are in service or currently under construction, 60.0 MW (19.8 percent) have been developed by transmission owners building in their own service territory. PECO is the transmission owner with the highest percentage of affiliates building battery projects in their own service territory. Of the 65.3 MW that entered the queue in the PECO Zone during the time period of January 1, 1997, through December 31, 2022, 40.0 MW (61.3 percent) have been submitted by PECO or one of their affiliated companies.

Table 12-52 Relationship between project developer and transmission owner for all battery project MW in the queue: December 31, 2022

			MW by Project Status						
Parent Company	Transmission Owner	Related to Developer	Active	In Service	Under Construction	Suspended	Withdrawn	Total	Percent of Total
AEP	AEP	Related	100.0	6.0	0.0	0.0	10.0	116.0	0.9%
		Unrelated	11,125.9	4.0	0.0	0.0	1,711.2	12,841.1	99.1%
AES	DAY	Related	0.0	20.0	0.0	0.0	0.0	20.0	2.6%
		Unrelated	340.0	0.0	0.0	0.0	414.9	754.9	97.4%
AMP	AMPT	Related	0.0	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	0.0%
DUQ	DUQ	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	505.0	0.0	0.0	0.0	20.0	525.0	100.0%
DOM	DOM	Related	1,151.7	0.0	20.0	0.0	0.0	1,171.7	6.7%
		Unrelated	14,131.5	0.0	0.0	0.0	2,156.4	16,287.9	93.3%
DUKE	DUKE	Related	0.0	14.0	0.0	0.0	23.3	37.3	5.8%
		Unrelated	527.2	6.0	0.0	0.0	72.2	605.4	94.2%
EKPC	EKPC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	176.0	0.0	0.0	0.0	20.3	196.3	100.0%
Exelon	ACEC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	1,739.5	0.0	0.0	0.0	181.0	1,920.5	100.0%
	BGE	Related	2.5	0.0	0.0	0.0	20.0	22.5	1.3%
		Unrelated	1,455.0	0.0	0.0	0.0	240.6	1,695.6	98.7%
	COMED	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	8,296.1	87.0	0.0	0.0	2,004.0	10,387.1	100.0%
	DPL	Related	1.0	0.0	0.0	0.0	0.0	1.0	0.1%
		Unrelated	1,063.0	0.0	0.0	0.0	364.0	1,427.0	99.9%
	PECO	Related	0.0	0.0	0.0	0.0	40.0	40.0	61.3%
		Unrelated	0.0	1.0	0.0	0.0	24.3	25.3	38.7%
	PEPCO	Related	1.0	0.0	0.0	0.0	0.0	1.0	0.1%
		Unrelated	795.0	0.0	0.0	0.0	20.0	815.0	99.9%
First Energy	APS	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	3,500.8	39.9	0.0	0.0	376.0	3,916.7	100.0%
	ATSI	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	2,418.0	0.0	0.0	0.0	226.4	2,644.4	100.0%
	JCPLC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	1,070.8	40.0	14.0	2.0	859.2	1,986.0	100.0%
	MEC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	955.2	0.0	0.0	0.0	244.7	1,199.9	100.0%
	PE	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	1,267.8	28.4	0.0	0.0	401.0	1,697.2	100.0%
OVEC	OVEC	Related	0.0	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	0.0%
PPL	PPL	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	465.0	20.0	0.0	20.0	319.8	824.8	100.0%
PSEG	PSEG	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	1,775.0	3.0	0.0	7.0	9.5	1,794.5	100.0%
Con Ed	REC	Related	0.0	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	0.0%
Total		Related	1,256.2	40.0	20.0	0.0	93.3	1,409.5	2.2%
		Unrelated	51,606.8	229.3	14.0	29.0	9,665.6	61,544.7	97.8%

Renewable Hybrid Project Developer and Transmission Owner Relationships

Table 12-53 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, 2022, by transmission owner and project status. Of the 23.1 renewable hybrid project MW that are in service or currently under construction, 3.7 MW (15.9 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 59.7 MW that entered the queue in the PSEG Zone during the time period of January 1, 1997, through December 31, 2022, 3.7 MW (6.2 percent) have been submitted by PSEG or one of their affiliated companies.

Table 12-53 Relationship between project developer and transmission owner for all hybrid project MW in the queue: December 31, 2022

			MW by Project Status						
Parent Company	Transmission Owner	Related to Developer	Active	In Service	Under Construction	Suspended	Withdrawn	Total	Percent of Total
AEP	AEP	Related	180.0	0.0	0.0	0.0	0.0	180.0	0.9%
		Unrelated	15,735.1	0.0	3.2	0.0	3,460.8	19,199.1	99.1%
AES	DAY	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	650.8	0.0	0.0	0.0	0.0	650.8	100.0%
AMP	AMPT	Related	0.0	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	0.0%
DUQ	DUQ	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	107.5	0.0	0.0	0.0	0.0	107.5	100.0%
DOM	DOM	Related	17.0	0.0	0.0	0.0	0.0	17.0	0.2%
		Unrelated	8,240.2	0.0	0.0	0.0	2,289.9	10,530.1	99.8%
DUKE	DUKE	Related	0.0	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	100.0%
EKPC	EKPC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	3,214.1	0.0	0.0	0.0	1,004.0	4,218.1	100.0%
Exelon	ACEC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	221.0	0.0	0.0	0.0	14.5	235.5	100.0%
	BGE	Related	0.0	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	0.0%
	COMED	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	3,198.5	0.0	0.0	0.0	986.9	4,185.4	100.0%
	DPL	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	270.0	0.0	0.0	0.0	104.5	374.5	100.0%
	PECO	Related	0.0	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	100.0%
	PEPCO	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	1,452.0	0.0	0.0	0.0	20.0	1,472.0	100.0%
First Energy	APS	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	3,214.7	16.3	0.0	32.5	568.0	3,831.6	100.0%
	ATSI	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	891.6	0.0	0.0	0.0	334.9	1,226.5	100.0%
	JCPLC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	215.0	0.0	0.0	0.0	20.0	235.0	100.0%
	MEC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	263.3	0.0	0.0	18.9	23.7	305.9	100.0%
	PE	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	1,603.6	0.0	0.0	3.0	184.2	1,790.9	100.0%
OVEC	OVEC	Related	0.0	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	100.0%
PPL	PPL	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	700.0	0.0	0.0	140.0	201.0	1,041.0	100.0%
PSEG	PSEG	Related	0.0	1.1	2.6	0.0	0.0	3.7	6.2%
		Unrelated	20.0	0.0	0.0	0.0	36.1	56.1	93.8%
Con Ed	REC	Related	0.0	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	0.0%
Total		Related	197.0	1.1	2.6	0.0	0.0	200.7	0.4%
		Unrelated	40,230.9	16.3	3.2	194.4	9,248.5	49,693.2	99.6%

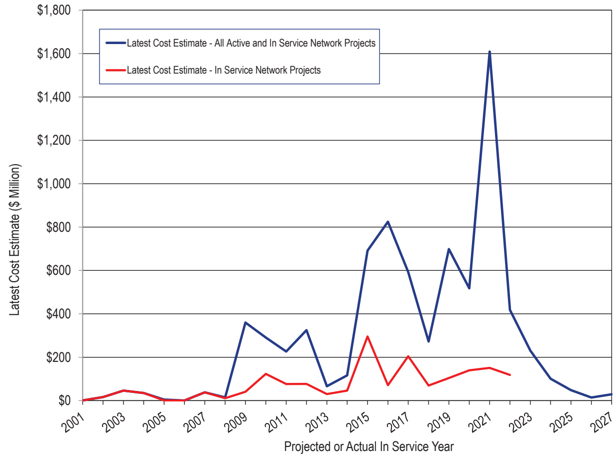
Network Transmission Project Costs

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.[60] PJM's process is designed to ensure that new generation is added in a reliable and systematic manner. 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. Transmission modifications necessary to maintain the reliability of the transmission system as a result of a new service request are identified in the facility study report. These identified modifications are known as network upgrades. While not all projects in the queue will require network upgrades to interconnect to the transmission system, the number of planned network transmission upgrades is strongly correlated with the number of active projects in the queue. The number of planned network upgrades is also strongly correlated with the number of new generation projects requesting interconnection as a capacity resource. To be a capacity resource, PJM performs deliverability studies that ensure that the energy from the proposed generator can be reliably provided to the PJM region. These studies identify additional network upgrades necessary to ensure that the transmission system is capable of delivering the aggregate system generating capacity at peak load with all firm transmission service modeled.[61] There are fewer network upgrades associated with energy only resources, as energy only resources are not required to be deliverable to the entire PJM footprint. If a project is withdrawn from the queue, the network upgrades associated with that project are no longer required.

Figure 12-5 shows the latest network transmission project cost estimates by projected or actual in service year for network projects in the status of active or in service, and for those projects already in service. The large amount of network upgrade costs in recent years is attributed to the large number of requests in the new services queue. However, as generation requests withdraw from the queue, the overall network costs decrease. Figure 12-5 also shows that there were a large number of network project costs projected based on resources expected to go in service in recent years. The projected in service dates for network projects are only updated periodically, and therefore, may not be an accurate predictor of when these projects are actually expected to go in service. PJM does not track final project costs, so the in service costs only reflect the last estimate provided by PJM before the project went in service.

60 See OATT Parts IV & VI.
61 See "PJM Manual 14B: PJM Regional Transmission Planning Process," Rev. 51 (December 15, 2021).

Figure 12-5 Cost estimates of network projects by projected or actual in service year: January 1, 2001 through December 31, 2027



Regional Transmission Expansion Plan (RTEP)[62]

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.

62 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).

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 Managers 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.[63] 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, submitted by an incumbent transmission owner, 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 28, 2015. This window accepted proposals to address historical congestion on 12 identified flowgates. PJM received 93 proposals from 19 entities. Thirteen projects, all submitted by an incumbent transmission owner, 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, all submitted by an incumbent transmission owner, 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,

63 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>.

submitted by an incumbent transmission owner, 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, submitted by an incumbent transmission owner, was approved by the PJM Board to address the historical congestion on the internal flowgate, and one project, submitted by an incumbent transmission owner, was approved by the PJM Board to address the historical congestion on one of the interregional flowgates.[64]

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. Four projects, all submitted by an incumbent transmission owner, were approved by the PJM Board.

The sixth market efficiency cycle is currently being performed for the 2022/2023 RTEP long term window. The 2022/2023 RTEP long term window is scheduled to open in January 2023. PJM is currently developing the market efficiency base case.

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.

64 No proposals effectively resolved the congestion on two of the three identified interregional market efficiency flowgates.

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.[65] Transource is appealing the decision at the state and federal level.[66]

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.[67] At the time of the suspension, $131.9 million in material, engineering, land rights and project support costs had been incurred by developers, but there was no increase in transmission capability associated with the project.[68]

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, 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

65 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.*, Pennsylvania Public Utility Commission, Opinion and Order, Docket No. A-2017-2640195 et al. (May 20, 2021).

66 See *Transource Pennsylvania, LLC et al. 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.).

67 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>.

68 Nick Dumitriu, Principal Engineer, PJM Market Simulation, Market Efficiency Update presented to the Transmission Expansion Advisory Committee (November 30, 2021) at 19 <https://www.pjm.com/-/media/committees-groups/committees/teac/2021/20211130/20211130-item-02-market-efficiency-update.ashx>.

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.[69] 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.

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 and MISO are currently performing an analysis to determine if an IMEP study will be required for the 2022/2023 IMEP cycle.

69 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>.

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.[70] [71]

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.[72] 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.

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. The 2022 TMEP study focused on 23 flowgates as potential TMEP projects. Of the 23 initial flowgates, 19 were eliminated due to their relationship with other existing reliability projects already included

70 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>.
71 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).
72 See *PJM Interconnection, L.L.C*, Docket No. ER17-729-000 (December 30, 2016).

in PJM's RTEP or MISO's MTEP plans, or the identified congestion was caused by outages.[73] Two projects were eliminated after studies showed that congestion was not persistent in October 2022, and an additional project was eliminated in December 2022 after further studies showed congestion was not persistent, leaving one TMEP project that will be recommended to the PJM and MISO Boards for implementation.[74] [75]

The PJM and MISO TMEP process for measuring the projected benefits of a TMEP transmission project 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.

Multi Driver Process

On September 12, 2014, PJM filed revisions to the tariff to include provisions allowing PJM to include multi driver projects in its regional transmission expansion plan.[76] When a transmission project addresses a combination of reliability, market efficiency and/or public policy objectives, PJM can develop a multi driver approach project by identifying a more efficient or cost effective solution. PJM may choose a solution using either the proportional multi driver method or the incremental multi driver method. The proportional method combines separate solutions that address reliability, economics and/or public policy into a single transmission enhancement or expansion that incorporates separate drivers into one Multi-Driver Project. The incremental method expands or enhances a proposed single-driver solution to include one or more additional component(s) to address a combination of reliability, economic and/or public policy drivers.[77] On February 20, 2015, the Commission approved the tariff revisions with an effective date of November 12, 2014.[78]

On June 7, 2022, PJM opened its first multi driver proposal window. The window seeks to address reliability and market efficiency needs on three identified facilities. PJM accepted proposed solutions until August 8, 2022. PJM received 14 proposals from three entities. After conducting an independent cost review, a reliability analysis and a market efficiency analysis on the 14 proposals and a combination of the proposals, PJM proposed a combination of two proposals (Project 644 + 908) as its preferred solution. The preferred solution (Project 644 + 908) has an estimated capital cost of $82.30 million ($85.50 million in present value of payments), with a PJM determined expected cost/benefit ratio of 1.99.[79] PJM has shared its recommendation with MISO for their evaluation. The cost/benefit analysis used in the multi driver review is the same flawed cost/benefit analysis that PJM uses for evaluating Market Efficiency projects. PJM's assumed benefit of the combined project was calculated as the sum of the present value of positive (energy cost reductions) effects of $169.8 million. The sum of the present value of negative effects (energy cost increases), which was ignored in the PJM calculation of benefits, was $149.1 million. The total benefit of the proposed multi driver project is therefore only $20.7 million, not the $169.8 asserted by PJM. Using the total benefits (positive and negative) to compare to the net present value of costs in the PJM's analysis, the benefit to cost ratio is 0.24, not 1.99. All $149.1 million of the increases in energy costs (negative benefits) would be paid by load in the ComEd zone.

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

73 See "Interregional Planning Update," presented at the August 9, 2022 meeting of the Transmission Expansion Advisory Committee. <https://www.pjm.com/-/media/committees-groups/committees/teac/2022/20220809/item-01---interregional-planning-update.ashx>.

74 See "Interregional Planning Update," presented at the October 4, 2022 meeting of the Transmission Expansion Advisory Committee. <https://www.pjm.com/-/media/committees-groups/committees/teac/2022/20221004/item-01----interregional-planning-update.ashx>.

75 See "PJM-MISO IPSAC," presented at the December 15, 2022 meeting of the PJM-MISO Interregional Planning Stakeholder Advisory Committee <https://www.pjm.com/-/media/committees-groups/stakeholder-meetings/ipsac/2022/20221215/ipsac-presentation.ashx>.

76 See PJM. Docket No. ER14-2864 (September 12, 2014).

77 See "PJM Manual 14B: PJM Region Transmission Planning Process," Rev. 51 (December 15, 2021).

78 150 FERC ¶ 61,117 (February 20, 2015).

79 See "2022 RTEP Multi-Driver Proposal Window No. 1," presented at the December 6, 2022 meeting of the Transmission Expansion Advisory Committee <https://www.pjm.com/-/media/committees-groups/committees/teac/2022/20221206/item-07---multi-driver-proposal-window-update.ashx>.

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

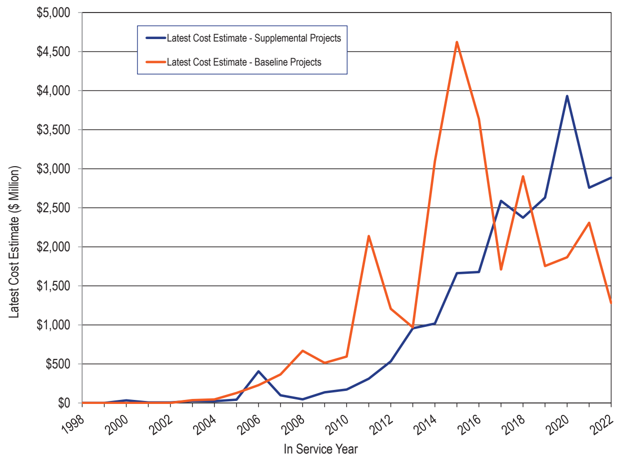
The M-3 Process requires TOs to present the criteria, assumptions and models that they will use to plan and identify Supplemental Projects on a yearly basis. The criteria identified for Supplemental Projects are very broad and include: equipment material condition, performance and risk, operational flexibility 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.[81] 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 12-6 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 12-6, Table 12-54 and Table 12-55 because PJM did not track or report such projects. There has been a significant increase in supplemental projects coincident with the implementation of Order No. 890 starting in 2008 and the competitive planning process introduced by FERC Order No. 1000 starting in 2011.

Figure 12-6 Cost estimate of baseline and supplemental projects by expected in service year: January 1, 1998 through December 31, 2022



80 See PJM. Planning. "Transmission Construction Status," (Accessed on December 31, 2022) <http://www.pjm.com/planning/rtep-upgrades-status/construct-status.aspx>.

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

Table 12-54 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 855.0 percent, from 20 for years 1998 through 2007 (pre Order No. 890) to 191 for years 2008 through 2022 (post Order No. 890). As of December 31, 2022, there are 1,603 supplemental projects with expected in service dates between 2023 and 2027.

Table 12-54 Number of supplemental projects by expected in service year and zone: 1998 through 2040

Year	ACEC	AEP	AMPT	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	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	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	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	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	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	0	10	0	0	0	0	0	0	2	0	0	0	0	15
2004	5	0	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	0	8	0	0	4	0	0	0	1	14	0	1	0	0	0	1	2	0	0	2	0	39
2006	4	2	0	5	0	0	6	0	0	0	0	9	0	1	0	0	0	0	1	0	2	1	0	31
2007	1	1	0	5	0	4	5	0	0	4	0	6	0	0	0	0	0	0	2	0	1	6	0	35
2008	3	0	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	0	6	0	1	8	0	0	3	3	5	0	0	0	0	0	5	1	0	1	2	0	39
2010	0	6	0	7	0	3	4	0	0	6	3	0	0	1	2	0	0	2	0	0	3	5	0	42
2011	0	8	0	8	0	0	2	0	0	5	2	0	0	1	0	0	0	4	0	0	6	4	0	40
2012	0	5	0	6	4	1	2	0	7	3	16	1	0	2	0	0	0	1	0	0	5	11	0	64
2013	5	21	0	4	5	0	11	0	6	4	13	1	0	1	1	0	0	1	0	1	14	19	0	107
2014	2	31	0	2	8	2	14	0	5	6	18	3	3	2	0	0	0	1	2	0	9	16	0	124
2015	4	15	0	2	9	1	37	0	8	4	17	5	3	2	0	0	0	1	0	4	7	24	0	143
2016	6	17	0	4	17	0	26	0	6	2	13	4	2	0	1	0	0	3	2	3	11	30	0	147
2017	8	107	0	3	26	1	23	0	3	8	31	11	5	0	3	0	0	0	3	1	22	43	0	298
2018	10	143	0	3	13	1	20	0	14	3	22	6	4	0	0	0	0	2	0	1	20	26	0	288
2019	3	160	0	4	30	5	14	2	16	1	33	8	5	3	14	0	0	1	15	0	15	27	0	356
2020	5	132	0	4	33	6	12	5	13	1	30	2	6	10	17	0	0	3	35	1	17	22	0	354
2021	4	152	0	6	31	7	3	7	13	2	22	0	8	15	24	0	0	23	24	0	19	22	0	382
2022	1	156	0	9	40	5	9	7	9	1	43	2	6	17	54	0	0	6	36	4	17	19	0	441
2023	9	369	1	4	24	0	6	19	8	1	30	4	7	1	32	2	5	5	32	2	15	25	0	601
2024	7	262	0	0	11	2	4	12	5	0	21	5	3	14	29	0	0	0	45	4	15	11	0	450
2025	7	225	1	1	13	3	2	12	2	1	25	3	1	0	23	0	0	1	30	1	12	14	0	377
2026	5	42	0	0	9	7	1	4	3	0	18	2	2	1	5	0	0	0	2	0	5	17	0	123
2027	1	28	0	0	4	1	0	0	2	2	2	1	2	0	1	0	0	0	0	0	6	2	0	52
2028	0	16	0	0	0	0	0	0	2	1	1	1	2	0	0	0	0	1	1	0	5	0	0	30
2029	0	0	0	0	0	3	0	0	0	0	0	0	0	0	0	0	0	0	2	0	12	0	0	17
2030	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	9	0	0	9
2031	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	9	0	0	10
2032	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	7	0	0	7
2033	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	7	0	0	7
2034	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	6	0	0	0	0	6
2035	0	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	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	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	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	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	0
Total	100	1,901	2	116	278	54	228	68	122	59	371	158	59	74	207	2	5	61	243	22	274	351	0	4,755

Table 12-55 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 2,450.1 percent, from $64.6 million for years 1998 through 2007 (pre Order No. 890) to $1.6 billion for years 2008 through 2022 (post Order No. 890). As of December 31, 2022, the 1,603 supplemental projects with expected in service dates between 2023 and 2027, have a total cost estimate of $17.9 billion.

Table 12-55 Latest cost estimate by expected in service year and zone ($ millions): 1998 through 2040

Year	ACEC	AEP	AMPT	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	$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	$0.00	$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	$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	$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	$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	$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	$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	$0.00	$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	$0.00	$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	$0.00	$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	$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	$0.00	$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	$0.00	$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	$0.00	$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	$0.00	$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	$0.00	$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	$0.00	$5.97	$58.70	$21.20	$60.37	$0.00	$2.43	$14.90	$88.61	$5.96	$0.72	$5.60	$0.00	$0.00	$0.00	$13.30	$1.30	$0.00	$33.47	$309.71	$0.00	$1,017.27
2015	$3.73	$237.45	$0.00	$3.80	$21.90	$2.00	$376.00	$0.00	$14.12	$4.53	$113.53	$13.06	$1.22	$0.30	$0.00	$0.00	$0.00	$33.80	$0.00	$42.50	$50.17	$743.91	$0.00	$1,662.02
2016	$74.54	$84.13	$0.00	$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	$0.00	$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	$816.23	$0.00	$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	$2,372.39
2019	$64.30	$1,163.04	$0.00	$11.97	$190.40	$76.55	$90.19	$0.30	$90.69	$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	$2,630.51
2020	$59.58	$920.44	$0.00	$0.30	$112.78	$62.58	$78.09	$13.66	$72.06	$6.40	$258.72	$39.50	$25.61	$2.60	$23.10	$0.00	$0.00	$2.40	$74.50	$102.70	$215.29	$1,861.58	$0.00	$3,931.89
2021	$86.54	$1,079.60	$0.00	$9.50	$184.21	$32.85	$125.70	$26.10	$117.39	$18.90	$98.40	$0.00	$25.67	$46.70	$85.89	$0.00	$0.00	$74.44	$63.48	$0.00	$197.67	$483.34	$0.00	$2,756.38
2022	$81.40	$674.66	$0.00	$11.12	$267.26	$203.30	$123.10	$36.05	$103.25	$45.00	$249.63	$9.38	$27.00	$31.50	$152.78	$0.00	$0.00	$73.68	$52.31	$2.79	$213.97	$527.63	$0.00	$2,885.81
2023	$185.45	$2,481.67	$11.25	$14.14	$169.88	$0.00	$33.10	$63.07	$63.58	$0.00	$213.16	$72.90	$43.06	$0.00	$222.76	$63.40	$4.40	$191.60	$109.60	$4.02	$176.28	$835.69	$0.00	$4,959.01
2024	$76.01	$1,917.76	$0.00	$0.00	$145.93	$118.00	$215.80	$92.20	$50.84	$0.00	$490.57	$87.80	$31.99	$103.90	$129.76	$0.00	$0.00	$0.00	$78.00	$809.47	$241.50	$347.41	$0.00	$4,936.94
2025	$173.99	$1,577.39	$5.70	$60.00	$217.60	$144.10	$104.00	$57.40	$10.76	$34.00	$540.39	$51.40	$3.80	$0.00	$136.30	$0.00	$0.00	$3.00	$72.10	$0.50	$368.90	$380.63	$0.00	$3,941.96
2026	$95.50	$498.35	$0.00	$0.00	$196.50	$687.25	$67.00	$11.90	$19.80	$0.00	$276.40	$58.78	$21.90	$16.00	$33.30	$0.00	$0.00	$0.00	$41.10	$0.00	$258.00	$404.50	$0.00	$2,686.28
2027	$17.13	$381.33	$0.00	$0.00	$404.00	$0.00	$0.00	$0.00	$30.62	$160.00	$100.00	$6.10	$28.01	$0.00	$10.00	$0.00	$0.00	$0.00	$0.00	$0.00	$83.80	$180.80	$0.00	$1,401.79
2028	$0.00	$365.44	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$29.57	$30.40	$0.00	$15.00	$30.78	$0.00	$0.00	$0.00	$0.00	$71.00	$138.00	$0.00	$112.26	$0.00	$0.00	$792.45
2029	$0.00	$0.00	$0.00	$0.00	$0.00	$276.00	$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	$136.39	$0.00	$0.00	$612.39
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	$0.00	$181.88	$0.00	$0.00	$181.88
2031	$0.00	$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	$192.80	$0.00	$0.00	$272.80
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	$154.80	$0.00	$0.00	$154.80
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	$116.28	$0.00	$0.00	$116.28
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	$0.00	$443.00	$0.00	$0.00	$0.00	$0.00	$443.00
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	$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	$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	$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	$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	$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	$0.00
Total	$1,085.83	$13,813.45	$16.95	$241.21	$2,472.46	$1,692.16	$1,968.33	$300.68	$790.34	$548.35	$3,134.99	$690.47	$276.76	$221.35	$881.94	$63.40	$4.40	$828.02	$1,371.72	$1,140.18	$3,668.72	$9,613.69	$0.00	$44,825.40

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.[82]

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.

82 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.[83] 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.[84] Some supplemental projects are in this category. In a decision issued August 19, 2022, the U.S. Court of Appeals for the D.C Circuit found that FERC reasonably approved MISO's Immediate Need Reliability Exception.[85] The Court rejected arguments challenging the MISO rule because (i) the definition of projects eligible for the exception was insufficiently limited and (ii) the rule allows for designating the incumbent developer before posting of the basis for the exception.[86] The decision was largely based on deference to FERC expertise.[87]
- **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.[88] 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.[89] 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.

Dominion Data Center Alley Immediate Need

An area in northern Virginia in the Dominion Transmission Zone, known as Data Center Alley, has experienced significant load growth due to increases in customer requests for data centers in the area. As a result, Dominion has presented 44 supplemental project requests to serve the increase in load through the summer of 2025. As part of the supplemental planning process, PJM performs a do no harm analysis. PJM has identified the need for additional baseline reinforcements to support the load growth. "Due to the pace and magnitude of load increase in the data center alley area, current operational and reliability constraints on the transmission system to serve load and consideration that a shortened competitive window will lead to delays of about 6 months, PJM has determined to designate Dominion construction responsibility to mitigate these immediate need violations."[90] [91] The proposed solution includes 500kV and 230kV lines extensions, the reconductoring of multiple 230kV lines and substation work. The initial cost estimate for the scope of work is $627.6 million.[92]

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

83 See OA Schedule 6 § 1.5.8(m).
84 169 FERC ¶ 61,054 (2019).
85 LSP Transmission Holdings II, LLC v. FERC, 45 F.4th 979.
86 *Id.* at 999.
87 *Id.*
88 See OA Schedule 6 § 1.5.8(n).
89 See OA Schedule 6 § 1.5.8(p).
90 See "Dominion Northern Virginia Area Violations," presented at the July 12, 2022 meeting of the Transmission Expansion Advisory Committee. <https://www.pjm.com/-/media/committees-groups/committees/teac/2022/20220712/item-08---dominion-northern-virginia-area-violations---need-statement.ashx>.
91 See "Dominion Northern Virginia Area Immediate Need," presented at the July 12, 2022 meeting of the Transmission Expansion Advisory Committee. <https://www.pjm.com/-/media/committees-groups/committees/teac/2022/20220712/item-08---dominion-northern-virginia---immediate-need.ashx>.
92 See "Reliability Analysis Update Immediate Need," presented at the September 6, 2022 meeting of the Transmission Expansion Advisory Committee. <https://www.pjm.com/-/media/committees-groups/committees/teac/2022/20220906/item-09a---reliability-analysis-update---immediate-need.ashx>.

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.[93]

The 2020 RTEP Window 1 was the first open window that received cost capping proposals to be evaluated under the comparative cost framework. PJM has not provided the requested data to the MMU to allow for an analysis of their financial review process. Without this analysis, the MMU cannot verify that the analysis performed under the comparative cost framework was sufficient or adequately followed the process defined in the PJM manual.[94] 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.[95]

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

On July 22, 2020, through the supplemental planning process, American Electric Power Service Corporation (AEP) filed, on behalf of Kentucky Power Company (Kentucky Power), a Petition for Declaratory Order seeking confirmation that its Middle Creek energy storage project is eligible for cost-of-service recovery through AEP's formula rates.[96] 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.[97]

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.[98]

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 2022, the PJM Board approved a net change of $2.6 billion in transmission upgrades. On February 18, 2022, the PJM Board authorized $515.4 million in transmission

93 170 FERC ¶ 61,243 (2020).
94 See "PJM Manual 14F: Competitive Planning Process," Rev. 9 (April 27, 2022).
95 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>.
96 See *AEP*, Docket No. EL20-58 (July 22, 2020).
97 173 FERC ¶ 61,264 (2020).
98 Supplemental Projects, including the end of life subset of supplemental projects, do not require PJM Board of Managers authorization.

upgrades and additions. On July 12, 2022, the PJM Board authorized $82.1 million in transmission upgrades and additions. On October 4, 2022, the PJM Board authorized $642.8 million in transmission upgrades and additions. On December 19, 2022, the PJM Board authorized $1.4 billion in transmission upgrades and additions. As of December 31, 2022, the PJM Board had approved $41.5 billion in transmission system enhancements since 1999.

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, 2022, no QTUs have cleared a BRA or IA.

Cost Allocation

In response to complaints against PJM RTEP Baseline Upgrade Filings in 2014 that included cost allocations for $1.5 billion in baseline transmission enhancements and expansions, on November 24, 2015, FERC issued an order directing investigation of "whether there is a definable category of reliability projects within PJM for which the solution-based DFAX cost allocation method may not be just and reasonable, such as projects addressing reliability violations that are not related to flow on the planned transmission facility, and whether an alternative just and reasonable *ex ante* cost allocation method could be established for any such category of projects."[99] FERC convened a technical conference on January 12, 2016, to address the complaints in multiple proceedings and to address these two core issues.[100]

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.[101] 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. On appeal, the U.S. Court of Appeals for the D.C. Circuit found that FERC had failed to explain its distinction between projects for use of the dfax method and rejected the 0.01 distribution cutoff factor as "absurd."[102] Issues concerning PJM's solution based dfax method are now pending at FERC on remand.

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 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 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.

99 153 FERC ¶ 61,245 at P 35 (2015).
100 See Docket Nos. EL15-18-000 (ConEd), EL15-67-000 (Linden), and EL15-95-000 (Artificial Island).
101 170 FERC ¶ 61,122 (2020).
102 See *Consolidated Edison v. FERC et al.*, 15-1183 et al (D.C. Cir. August 9, 2022).

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.[103]

LMP may, at times, be set by transmission penalty factors. When a transmission constraint is binding and there are no generation alternatives to resolve the constraint, system operators may allow the transmission limit to be violated. When this occurs, the shadow price of the constraint is set by transmission penalty factors. The shadow price directly affects the LMP. Transmission penalty factors are administratively determined and can be thought of as a form of locational scarcity pricing. Transmission penalty factors were fully implemented in PJM pricing effective February 1, 2019. The default transmission penalty factor is $2,000 per MWh.

103 See the *2018 State of the Market Report for PJM*, Volume II, Section 11: Congestion and Marginal Losses.

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.[104] 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.[105]

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.[106]

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.

104 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>.

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

106 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).

In PJM, transmission owners use a range of ratings by duration.[107] 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.[108]

Given the significant impact of transmission line ratings on all aspects of wholesale power markets, ensuring and improving the accuracy and transparency of line ratings is essential. Line ratings should incorporate ambient temperature conditions, wind speed and other relevant operating conditions. PJM real-time prices are calculated every five minutes for thousands of nodes. PJM prices are extremely sensitive to transmission line ratings. For consistency with the dynamic nature of wholesale power markets, line ratings should be updated in real time to reflect real time conditions and to help ensure that real-time prices are based on actual current line ratings. 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.[109] 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.[110] All line rating changes and the detailed reasons for those changes should be public and fully transparent.

The Commission recently adopted rules that enhance the ability of PJM and the MMU to understand and monitor line ratings on the PJM grid. Order No. 881, issued December 16, 2021, requires that: transmission providers implement ambient-adjusted ratings on transmission lines; RTOs/ISOs implement the systems and procedures necessary for hourly ratings updates; transmission providers use uniquely determined emergency ratings;

107 See "PJM Manual 3: Transmission Operations," Rev. 63 (Nov. 16, 2022) § 2.1.1, at p 27.
108 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.
109 *See* "Transmission Owner Ratings Development and Reporting in PJM," presented at May 3, 2018 meeting of the Planning Committee.
110 *See* the *2018 State of the Market Report for PJM*, Volume II, Section 2: Recommendations.

transmission owners share transmission line ratings and transmission line rating methods with RTOs/ISOs and market monitors; transmission providers maintain a database of transmission line ratings and transmission line rating methods on OASIS or other password-protected website.[111] [112]

On rehearing, the Commission provided clarification of market monitors' ability to take action based on information received about transmission line ratings: "We expect that market monitors may use the transmission line rating information available to them in furtherance of their existing responsibilities, which are set forth in the Commission's regulations and the relevant tariffs of each RTO/ISO."[113]

Order No. 881 enhances transparency of information on line ratings and how they are determined. Requiring ambient and hourly adjustments constitutes substantive improvement. Continued reform consistent with the MMU's recommendations is needed in order to ensure consistent and accurate transmission line ratings in PJM.

Order No. 881 did not require the use of dynamic line ratings ("DLR") based on an insufficient record.[114] But on February 17, 2022, in Docket No. AD22-5, FERC issued a notice of inquiry addressing the DLR issues.[115]

Dynamic Line Ratings (DLR) and Grid Enhancing Technology (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 (DLR) 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.

As a first step towards broader implementation of DLR by all transmission owners in PJM, PPL Electric Utilities, on its own initiative, implemented DLR for three 230 KV transmission lines in northeastern Pennsylvania on October 6, 2022, that have experienced congestion. (The two circuit Susquehanna-Harwood path and the Juniata-Cumberland line.) PPL provides streaming data from the DLR system to PJM operators.

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.[116] 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.[117] The specific timeline is shown in Table 12-57.[118]

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 2021/2022 planning period and the first seven months of 2022/2023 planning period, regardless of when they were initially submitted.[119] The outage data for the day-ahead market are for outages scheduled to occur from January 2015 through December 2022.

Transmission outages are categorized by duration: greater than 30 calendar days; less than or equal to 30

111 *Managing Transmission Line Ratings*, Order No. 881, 177 FERC ¶ 61,179 at P 39 (2021) ("Order No. 881"), *order on reh'g*, Order No. 881-A, 179 FERC ¶ 61,125 (2022) ("Order No. 881-A").
112 *See* 18 CFR § 35.28(c)(5)&(g)(13).
113 Order No. 881-A at P 91.
114 Order No. 881 at PP 25, 254
115 *Implementation of Dynamic Line Ratings*, Notice of Inquiry, 178 FERC ¶ 61,110 (2022).
116 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. 63 (November 16, 2022).
117 See PJM, "Manual 3: Transmission Operations," Rev. 63 (November 16, 2022).
118 See PJM, "Manual 3: Transmission Operations," Rev. 63 (November 16, 2022).
119 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.

calendar days; greater than five calendar days; less than or equal to five calendar days.[120] Table 12-56 shows that 74.6 percent of requested outages were planned for less than or equal to five days and 10.1 percent of requested outages were planned for greater than 30 days in the first seven months of 2022/2023 planning period. Table 12-56 also shows that 77.3 percent of the requested outages were planned for less than or equal to five days and 8.0 percent of requested outages were planned for greater than 30 days in the 2021/2022 planning period.

Table 12-56 Transmission facility outage request summary by planned duration: June 2021 through December 2022

	2021/2022 (12 months)		2022/2023 (7 months)	
Planned Duration (Days)	Outage Requests	Percent of Total	Outage Requests	Percent of Total
<=5	15,187	77.3%	8,255	74.6%
>5 & <=30	2,872	14.6%	1,691	15.3%
>30	1,579	8.0%	1,114	10.1%
Total	19,638	100.0%	11,060	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 12-57.[121]

The purpose of the rules defined in Table 12-57 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.[122]

Table 12-57 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	Before 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

120 *Id.* at 70.
121 See PJM, "Manual 3: Transmission Operations," Rev. 63 (November 16, 2022).
122 See "Report of PJM Interconnection, L.L.C. on Transmission Oversight Procedures," Docket No. EL01-122-000 (November 2, 2001).

Table 12-58 shows a summary of requests by received status. In the first seven months of 2022/2023 planning period, 40.1 percent of outage requests received were late. In the 2021/2022 planning period, 40.1 percent of outage requests received were late.

Table 12-58 Transmission facility outage requests by received status: June 2021 through December 2022

	2021/2022 (12 months)				2022/2023 (7 months)			
Planned Duration (Days)	On Time	Late	Total	Percent Late	On Time	Late	Total	Percent Late
<=5	9,607	5,580	15,187	36.7%	5,233	3,022	8,255	36.6%
>5 & <=30	1,557	1,315	2,872	45.8%	922	769	1,691	45.5%
>30	600	979	1,579	62.0%	469	645	1,114	57.9%
Total	11,764	7,874	19,638	40.1%	6,624	4,436	11,060	40.1%

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.[123]

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.[124] Table 12-59 is a summary of outage requests by emergency status. Of all outage requests scheduled to occur in the first seven months of 2022/2023 planning period, 12.6 percent were for emergency outages. Of all outage requests scheduled to occur in the 2021/2022 planning period, 12.1 percent were for emergency outages.

123 See PJM, "Manual 3: Transmission Operations," Rev. 63 (November 16, 2022). 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).
124 PJM, "Manual 3: Transmission Operations," Rev. 63 (November 16, 2022).

Table 12-59 Transmission facility outage requests by emergency: June 2021 through December 2022

	2021/2022 (12 months)				2022/2023 (7 months)			
Planned Duration (Days)	Emergency	Non Emergency	Total	Percent Emergency	Emergency	Non Emergency	Total	Percent Emergency
<=5	1,749	13,438	15,187	11.5%	986	7,269	8,255	11.9%
>5 & <=30	357	2,515	2,872	12.4%	213	1,478	1,691	12.6%
>30	267	1,312	1,579	16.9%	194	920	1,114	17.4%
Total	2,373	17,265	19,638	12.1%	1,393	9,667	11,060	12.6%

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."[125]

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 12-60 is a summary of outage requests by congestion status. Of all outage requests submitted to occur in the first seven months of 2022/2023 planning period, 8.4 percent were expected to cause congestion. Of all the outage requests that were expected to cause congestion, 4.0 percent (37 out of 929) were denied by PJM in the first seven months of 2022/2023 planning period and 20.7 percent (192 out of 929) were cancelled (Table 12-62). Of all outage requests submitted to occur in the 2021/2022 planning period, 6.3 percent were expected to cause congestion. Of all the outage requests that were expected to cause congestion, 3.8 percent (47 out of 1,236) were denied by PJM in the 2021/2022 planning period and 19.6 percent (242 out of 1,236) were cancelled (Table 12-62).

Table 12-60 Transmission facility outage requests by congestion: June 2021 through December 2022

	2021/2022 (12 months)				2022/2023 (7 months)			
Planned Duration (Days)	Congestion Expected	No Congestion Expected	Total	Percent Congestion Expected	Congestion Expected	No Congestion Expected	Total	Percent Congestion Expected
<=5	918	14,269	15,187	6.0%	666	7,589	8,255	8.1%
>5 & <=30	211	2,661	2,872	7.3%	179	1,512	1,691	10.6%
>30	107	1,472	1,579	6.8%	84	1,030	1,114	7.5%
Total	1,236	18,402	19,638	6.3%	929	10,131	11,060	8.4%

Table 12-61 shows the outage requests summary by received status, congestion status and emergency status. In the first seven months of 2022/2023 planning period, 27.7 percent of requests were submitted late and were nonemergency while 1.2 percent of requests (128 out of 11,060) were late, nonemergency, and expected to cause congestion. In the 2021/2022 planning period, 28.3 percent of request were submitted late and were nonemergency while 1.1 percent of requests (221 out of 19,638) were late, nonemergency, and expected to cause congestion.

Table 12-61 Transmission facility outage requests by received status, emergency and congestion: June 2021 through December 2022

		2021/2022 (12 months)				2022/2023 (7 months)			
Received Status		Congestion Expected	No Congestion Expected	Total	Percent of Total	Congestion Expected	No Congestion Expected	Total	Percent of Total
Late	Emergency	56	2,261	2,317	11.8%	39	1,331	1,370	12.4%
	Non Emergency	221	5,336	5,557	28.3%	128	2,938	3,066	27.7%
On Time	Emergency	8	48	56	0.3%	5	18	23	0.2%
	Non Emergency	951	10,757	11,708	59.6%	757	5,844	6,601	59.7%
Total		1,236	18,402	19,638	100.0%	929	10,131	11,060	100.0%

125 PJM added this definition to Manual 38 in February 2017. PJM, "Manual 38: Operations Planning," Rev. 16 (Jan. 25, 2023).

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.[126] Table 12-62 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 12-62. Table 12-62 shows that of all the outage requests that were expected to cause congestion, 4.0 percent (37 out of 929) were denied by PJM in the first seven months of 2022/2023 planning period, 64.4 percent were complete and 20.7 percent (192 out of 929) were cancelled. Of all the outage requests that were expected to cause congestion, 3.8 percent (47 out of 1,236) were denied by PJM in the 2021/2022 planning period, 67.6 percent were complete and 19.6 percent (242 out of 1,236) were cancelled.

The treatment by PJM and Dominion Virginia Power of the outage for the Lanexa – Dunnsville Line illustrates some of the issues with the current process. The outage was submitted and delayed more than once. It is not clear that PJM's analysis of expected congestion identified or highlighted the magnitude of the issue. Dominion Virginia Power did not stage the outage so as to minimize market disruption and congestion. After high congestion costs of Greys Point - Harmony Village constraint and market participant manipulative behavior caused by the outage were identified by the end of January, on February 11, 2022 Dominion decided to temporarily terminate the outage in March in order to work on upgrading Greys Point, Harmony Village and White Stone path. The Greys Point - Harmony Village Line has not been binding since March 14, 2022. It indicates that if the market impact of the outage was identified during PJM outage analysis process and action was taken because of the analysis result, the high congestion costs and manipulative behavior could have been prevented.

Table 12-62 Transmission facility outage requests by processed status[127]: June 2021 through December 2022

		2021/2022 (12 months)						2022/2023 (7 months)					
Received Status		Cancelled	Complete	In Process	Denied	Congestion Expected	Percent Complete	Cancelled	Complete	In Process	Denied	Congestion Expected	Percent Complete
Late	Emergency	7	47	0	1	56	83.9%	1	38	0	0	39	97.4%
	Non Emergency	36	159	3	22	221	71.9%	18	96	7	6	128	75.0%
On Time	Emergency	2	6	0	0	8	75.0%	0	5	0	0	5	100.0%
	Non Emergency	197	624	93	24	951	65.6%	173	459	88	31	757	60.6%
Total		242	836	96	47	1,236	67.6%	192	598	95	37	929	64.4%

There are clear rules defined for assigning On Time or Late status for submitted outage requests in both the PJM tariff and PJM manuals.[128] However, the On Time or Late status only affects the priority that PJM assigns for processing the outage request. Table 12-62 shows that in the 2021/2022 planning period, 221 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 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 12-63 is a summary of all the outage requests planned for the 2021/2022 planning period and the first seven months of 2022/2023 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 2022/2023 planning period, 29.2 percent of transmission outage requests were approved by PJM and then rescheduled by the TOs, and 11.5 percent of the transmission outages were approved by PJM and subsequently cancelled by

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

127 The number of denied transmission outage requests is lower than calculated by PJM the MMU includes only the transmission outage requests with "Denied" as a final status, while PJM included both transmission outage requests with "Denied" as a final status and transmission outage requests with "Denied" as an intermediate status.

128 OA Schedule 1 § 1.9.2.

the TOs. In the 2021/2022 planning period, 29.8 percent of transmission outage requests were approved by PJM and then rescheduled by the TO, and 12.5 percent of the transmission outages were approved by PJM and subsequently cancelled by the TO.

Table 12-63 Rescheduled and cancelled transmission outage requests: June 2021 through December 2022

	2021/2022 (12 months)					2022/2023 (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	15,187	3,171	20.9%	2,156	14.2%	8,255	1,690	20.5%	1,106	13.4%
>5 & <=30	2,872	1,575	54.8%	210	7.3%	1,691	888	52.5%	133	7.9%
>30	1,579	1,113	70.5%	88	5.6%	1,114	647	58.1%	35	3.1%
Total	19,638	5,859	29.8%	2,454	12.5%	11,060	3,225	29.2%	1,274	11.5%

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.[129] 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.[130] 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 12-57) define a transmission outage request as On Time or Late based on the planned outage duration and the time of submission. The rule has stricter submission requirements for transmission outage requests planned for longer than 30 days. In order to avoid the stricter submission requirement, some transmission owners divided the duration of outage requests longer than 30 days into shorter segments for the same equipment and submitted one request for each segment. The MMU recommends that PJM not permit transmission owners to divide long duration outages into smaller segments to avoid complying with the requirements for long duration outages.

More than one outage request can be submitted for the same transmission equipment. In order to accurately present the results, Table 12-64 shows equipment outages by the equipment instead of by outage request.

Table 12-64 shows that there were 7,808 transmission equipment planned outages in the first seven months of 2022/2023 planning period, of which 1,067 or 13.7 percent were longer than 30 days, and of which 92 or 1.2 percent were scheduled longer than 30 days when the duration of all the outage requests are combined for the same equipment.

129 PJM, "Manual 3: Transmission Operations," Rev. 63 (November 16, 2022).
130 *Id.*

Table 12-64 Transmission equipment outages: June 2021 through December 2022

		2021/2022 (12 months)		2022/2023 (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	1,368	11.2%	975	12.5%
	Yes	238	2.0%	92	1.2%
<= 30		10,593	86.8%	6,741	86.3%
Total		12,199	100.0%	7,808	100.0%

Table 12-65 shows the details of long duration (> 30 days) outages when combining the duration of the outage requests for the same equipment.[131] 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 2022/2023 planning period, within effective duration greater than a month and shorter than two months, there were 30 outages with a combined duration longer than 30 days.

Table 12-65 Transmission equipment outages by effective duration: June 2021 through December 2022

	2021/2022 (12 months)		2022/2023 (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	3	1.3%	1	1.1%
>31 & <=62	29	12.2%	30	32.6%
>62 & <=93	20	8.4%	13	14.1%
>93	186	78.2%	48	52.2%
Total	238	100.0%	92	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.[132]

In the first seven months of 2022/2023 planning period, 239 outage requests were included in the annual FTR market outage list and 10,821 outage requests were not included.[133] In the 2021/2022 planning period, 367 outage requests were included in the annual FTR market outage list and 19,271 outage requests were not included. Table 12-66, Table 12-67, Table 12-68 and Table 12-69 show the summary information on the modeled outage requests and Table 12-70 and Table 12-71 show the summary information on outages that were not included in the Annual FTR Market.

Table 12-56 shows that 24.3 percent of the outage requests modeled in the Annual FTR Market for the first seven months of 2022/2023 planning period had a planned duration of less than two weeks and that 15.5 percent of the outage requests (37 out of 239) modeled in the Annual FTR Market for the planning period were submitted late according to outage submission rules. It also shows that 27.0 percent of the outage requests modeled in the Annual FTR Market for the 2021/2022 planning period had a planned duration of less than two weeks and that 16.3 percent of the outage requests (60 out of 367) modeled in the Annual FTR Market for the planning period were submitted late according to outage submission rules.

131 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.

132 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.

133 PJM's treatment of transmission outages in the FTR models is discussed in the *2022 State of the Market Report for PJM*: Section 13: FTRs and ARRs: Supply and Demand.

Table 12-66 Annual FTR market modeled transmission facility outage requests by received status: June 2021 through December 2022

	2021/2022 (12 months)				2022/2023 (7 months)			
Planned Duration	On Time	Late	Total	Percent of Total	On Time	Late	Total	Percent of Total
<2 weeks	86	13	99	27.0%	55	3	58	24.3%
>=2 weeks & <2 months	128	16	144	39.2%	67	9	76	31.8%
>=2 months	93	31	124	33.8%	80	25	105	43.9%
Total	307	60	367	100.0%	202	37	239	100.0%

Table 12-67 shows the annual FTR market modeled outage requests summary by emergency status and received status. Three of the annual FTR market modeled outages expected to occur in the first seven months of 2022/2023 planning period were emergency outages. None of the modeled outages expected to occur in the 2021/2022 planning period were emergency outages.

Table 12-67 Annual FTR market modeled transmission facility outage requests by emergency: June 2021 through December 2022

		2021/2022 (12 months)				2022/2023 (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	86	86	100.0%	0	55	55	100.0%
	>=2 weeks & <2 months	0	128	128	100.0%	0	67	67	100.0%
	>=2 months	0	93	93	100.0%	0	80	80	100.0%
	Total	0	307	307	100.0%	0	202	202	100.0%
Late	<2 weeks	0	13	13	100.0%	1	2	3	66.7%
	>=2 weeks & <2 months	0	16	16	100.0%	0	9	9	100.0%
	>=2 months	0	31	31	100.0%	2	23	25	92.0%
	Total	0	60	60	100.0%	3	34	37	91.9%

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 12-68 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 2022/2023 planning period and submitted late, 8.1 (3 out of 37) was expected to cause congestion. Overall, of all the annual FTR market modeled outages expected to occur in the 2021/2022 planning period and submitted late, 20.0 percent (12 out of 60) were expected to cause congestion.

Table 12-68 Annual FTR market modeled transmission facility outage requests by congestion: June 2021 through December 2022

		2021/2022 (12 months)				2022/2023 (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	14	72	86	16.3%	15	40	55	27.3%
	>=2 weeks & <2 months	35	93	128	27.3%	11	56	67	16.4%
	>=2 months	18	75	93	19.4%	20	60	80	25.0%
	Total	67	240	307	21.8%	46	156	202	22.8%
Late	<2 weeks	2	11	13	15.4%	0	3	3	0.0%
	>=2 weeks & <2 months	6	10	16	37.5%	1	8	9	11.1%
	>=2 months	4	27	31	12.9%	2	23	25	8.0%
	Total	12	48	60	20.0%	3	34	37	8.1%

Table 12-69 shows that 26.3 percent of outage requests modeled in the annual FTR market for the first seven months of 2022/2023 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 20.1 percent for the 2021/2022 planning period. Table 12-69 also shows that 16.2 percent of outages requests modeled in the Annual FTR Market for the first seven months of 2022/2023 planning period and with a duration of two months or longer were cancelled, compared to 20.2 percent for the 2021/2022 planning period.

Table 12-69 Annual FTR market modeled transmission facility outage requests by processed status: June 2021 through December 2022

		2021/2022 (12 months)		2022/2023 (7 months)	
Planned Duration	Processed Status	Outage Requests	Percent	Outage Requests	Percent
<2 weeks	In Progress	11	11.1%	5	8.6%
	Denied	1	1.0%	0	0.0%
	Approved	0	0.0%	1	1.7%
	Cancelled	27	27.3%	22	37.9%
	Revised	0	0.0%	0	0.0%
	Active	0	0.0%	0	0.0%
	Completed	60	60.6%	30	51.7%
	Total	99	100.0%	58	100.0%
>=2 weeks & <2 months	In Progress	28	19.4%	10	13.2%
	Denied	1	0.7%	0	0.0%
	Approved	0	0.0%	0	0.0%
	Cancelled	29	20.1%	20	26.3%
	Revised	1	0.7%	0	0.0%
	Active	0	0.0%	0	0.0%
	Completed	85	59.0%	46	60.5%
	Total	144	100.0%	76	100.0%
>=2 months	In Progress	10	8.1%	16	15.2%
	Denied	0	0.0%	0	0.0%
	Approved	3	2.4%	1	1.0%
	Cancelled	25	20.2%	17	16.2%
	Revised	0	0.0%	0	0.0%
	Active	2	1.6%	29	27.6%
	Completed	84	67.7%	42	40.0%
	Total	124	100.0%	105	100.0%
Total Cancelled		81	22.1%	59	24.7%
Grand Total		367		239	

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 2022/2023 planning period, 239 outage requests were modeled and 10,821 outage requests were not modeled in the Annual FTR Market. In the 2021/2022 planning period, 367 outage requests were modeled and 19,271 outage requests were not modeled in the Annual FTR Market.

Table 12-70 shows that 8.0 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 2022/2023 planning period compared to 13.7 percent in the 2021/2022 planning period.

Table 12-70 Transmission facility outage requests not modeled in Annual FTR Auction: June 2021 through December 2022

	2021/2022 (12 months)						2022/2023 (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	1,927	8,363	81.3%	222	6,103	96.5%	1,753	3,862	68.8%	177	3,277	94.9%
>=2 weeks & <2 months	641	351	35.4%	129	796	86.1%	557	74	11.7%	117	421	78.3%
>=2 months	151	24	13.7%	191	373	66.1%	162	14	8.0%	207	200	49.1%
Total	2,719	8,738	76.3%	542	7,272	93.1%	2,472	3,950	61.5%	501	3,898	88.6%

Table 12-71 shows that 91.5 percent of late outage requests that were submitted after the Annual FTR Auction bidding opening date, were not modeled in the Annual FTR Auction, and had a duration longer than or equal to two months, were completed in the first seven months of 2022/2023 planning period. It also shows that 91.2 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 2021/2022 planning period.

Table 12-71 Late transmission facility outage requests: June 2021 through December 2022

	2021/2022 (12 months)			2022/2023 (7 months)		
Planned Duration	Completed Outages	Total	Percent Complete	Completed Outages	Total	Percent Complete
<2 weeks	5,287	6,103	86.6%	2,838	3,277	86.6%
>=2 weeks & <2 months	697	796	87.6%	363	421	86.2%
>=2 months	340	373	91.2%	183	200	91.5%
Total	6,324	7,272	87.0%	3,384	3,898	86.8%

Although the definition of late outages was developed in order to prevent outages for the planning period being submitted after the opening of bidding in the Annual FTR Auction, the rules have not functioned effectively because the rule has no direct connection to the date on which bidding opens for the Annual FTR Auction. By requiring all long-duration transmission outages to be submitted before February 1, PJM outage submission rules only prevent long-duration transmission outages from being submitted late. The rule does not address the situation in which long-duration transmission outages are submitted on time, but are rescheduled so that they are late. There is no rule to address the situation in which short-duration outages (duration <= 5 days) are submitted on time, but are changed to long-duration transmission outages after the outages are approved and active. The Annual FTR Auction model may consider transmission outages planned for longer than two weeks but less than two months. Those outages not only include long duration outages but also include outages shorter than 30 days. In those cases, PJM outage submission rules failed to prevent 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.[134] Table 12-72 and Table 12-73 show the summary information on outage requests modeled in the Monthly Balance of Planning Period FTR Auction and Table 12-74 and Table 12-75 show the summary information on outage requests not modeled in the Monthly Balance of Planning Period FTR Auction.

Table 12-72 shows that on average, 28.1 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 2022/2023 planning period. On average, 33.1 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 2021/2022 planning period.

134 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 12-72 Monthly Balance of Planning Period FTR Auction modeled transmission facility outage requests by received status: June 2021 through December 2022

	2021/2022				2022/2023			
Month	On Time	Late	Total	Percent Late	On Time	Late	Total	Percent Late
Jun	209	116	325	35.7%	246	101	347	29.1%
Jul	103	85	188	45.2%	147	87	234	37.2%
Aug	125	81	206	39.3%	160	85	245	34.7%
Sep	363	147	510	28.8%	483	156	639	24.4%
Oct	480	192	672	28.6%	635	203	838	24.2%
Nov	454	205	659	31.1%	531	164	695	23.6%
Dec	325	153	478	32.0%	407	127	534	23.8%
Jan	214	118	332	35.5%				
Feb	216	121	337	35.9%				
Mar	399	142	541	26.2%				
Apr	454	172	626	27.5%				
May	402	182	584	31.2%				
Average	312	143	455	33.1%	373	132	505	28.1%

Table 12-73 shows that on average, 18.9 percent of outage requests modeled in the Monthly Balance of Planning Period FTR Auction were cancelled in the first seven months of 2022/2023 planning period. On average, 17.4 percent of outage requests modeled in the Monthly Balance of Planning Period FTR Auction were cancelled in the 2021/2022 planning period.

Table 12-73 Monthly Balance of Planning Period FTR Auction modeled transmission facility outage requests by processed status: June 2021 through December 2022

Planning Year	Month	In Process	Denied	Approved	Cancelled	Revised	Active	Complete	Total	Percent Cancelled
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%
	Jan	41	1	19	61	0	96	114	332	18.4%
	Feb	43	1	17	54	0	105	117	337	16.0%
	Mar	64	2	15	109	0	157	194	541	20.1%
	Apr	55	2	20	117	0	163	269	626	18.7%
	May	60	8	25	106	0	122	263	584	18.2%
	Average	44	3	14	79	0	129	185	455	17.4%
2022/2023	Jun	27	16	14	57	0	78	155	347	16.4%
	Jul	20	9	7	40	0	81	77	234	17.1%
	Aug	19	7	10	37	0	81	91	245	15.1%
	Sep	65	6	24	130	1	210	203	639	20.3%
	Oct	86	7	23	180	2	213	327	838	21.5%
	Nov	57	3	16	140	1	198	280	695	20.1%
	Dec	41	5	9	116	1	79	283	534	21.7%
	Average	45	8	15	100	1	134	202	505	18.9%

Table 12-74 shows that on average, 10.7 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 2022/2023 planning period, compared to 9.3 percent in the 2021/2022 planning period. On average, 61.0 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 2022/2023 planning period, compared to 61.6 percent in the 2021/2022 planning period.

Table 12-74 Transmission facility outage requests not modeled in Monthly Balance of Planning Period FTR Auction: June 2021 through December 2022

	2021/2022						2022/2023					
	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	776	87	10.1%	323	613	65.5%	756	160	17.5%	313	557	64.0%
Jul	349	69	16.5%	272	501	64.8%	368	80	17.9%	247	465	65.3%
Aug	365	49	11.8%	262	464	63.9%	402	73	15.4%	279	466	62.6%
Sep	934	105	10.1%	318	615	65.9%	965	56	5.5%	326	504	60.7%
Oct	1,035	77	6.9%	385	663	63.3%	1,093	69	5.9%	346	543	61.1%
Nov	860	50	5.5%	411	516	55.7%	955	68	6.6%	426	495	53.7%
Dec	673	34	4.8%	340	525	60.7%	748	48	6.0%	361	531	59.5%
Jan	564	84	13.0%	308	461	59.9%						
Feb	697	68	8.9%	348	530	60.4%						
Mar	1,291	76	5.6%	331	586	63.9%						
Apr	1,525	118	7.2%	385	531	58.0%						
May	1,189	146	10.9%	420	572	57.7%						
Average	855	80	9.3%	342	548	61.6%	755	79	10.7%	328	509	61.0%

Table 12-75 shows that on average, 71.5 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 completed in the first seven months of 2022/2023 planning period, compared to 70.3 percent in the 2021/2022 planning period.

Table 12-75 Late transmission facility outage requests: June 2021 through December 2022

	2021/2022			2022/2023		
	Completed Outages	Total	Percent Complete	Completed Outages	Total	Percent Complete
Jun	419	613	68.4%	407	557	73.1%
Jul	371	501	74.1%	354	465	76.1%
Aug	307	464	66.2%	335	466	71.9%
Sep	408	615	66.3%	349	504	69.2%
Oct	470	663	70.9%	380	543	70.0%
Nov	347	516	67.2%	325	495	65.7%
Dec	402	525	76.6%	395	531	74.4%
Jan	301	461	65.3%			
Feb	370	530	69.8%			
Mar	407	586	69.5%			
Apr	383	531	72.1%			
May	439	572	76.7%			
Average	385	548	70.3%	364	509	71.5%

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.[135]

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 12-7 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;

135 PJM, "Manual 3: Transmission Operations," Rev. 63 (November 16, 2022).

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 12-7 Illustration of day-ahead market analysis: May 5, 2018

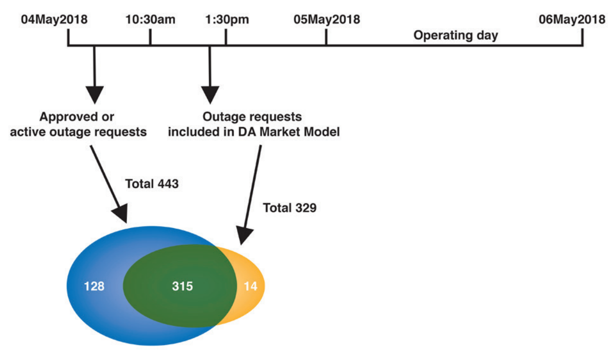


Figure 12-8 compares the weekly average number of active or approved outages available to market participants prior to the close of the day-ahead market with the outages included as inputs to the day-ahead market by PJM. Figure 12-8 shows that from the week of September 25, 2022, through the week of December 4, 2022, the number of outages included in the day-ahead market was closer to the number of outages for which information was available to market participants than previously. The average number of outages included in the day-ahead market increased from 256 outages (70.3 percent of average number of outages for which information was available to market participants) during the rest of weeks in 2022 to 449 outages (86.0 percent of average number of outages for which information was available to market participants) during the week of September 25, 2022, through the week of December 4, 2022.

Figure 12-8 Approved or active outage requests: January 2015 through December 2022

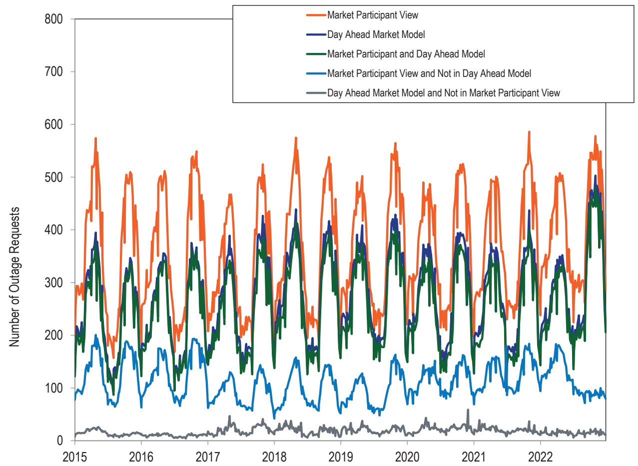


Figure 12-9 compares the weekly average number of outages included in the day-ahead market with the outages that actually occurred during the operating day. Figure 12-9 shows that for the period from the week of May 29, 2022, through the end of 2022, the average number of outages included in the day-ahead market increased from 273 (95.6 percent of the average number of outages that actually occurred) to 315 (127.5 percent of average number of outages that actually occurred). .

Figure 12-9 Day-ahead market model outages: January 2015 through December 2022

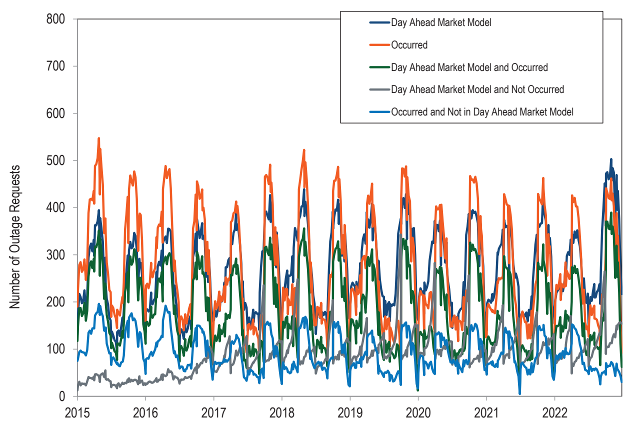


Figure 12-10 compares the weekly average number of active or approved outages for which information was available to market participants prior to the close of the day-ahead market with the outages that actually occurred during the operating day. The average number of outages that actually occurred were 74.7 percent of the average number of outages for which information was available to market participants.

Figure 12-10 Approved or active outage requests: January 2015 through December 2022

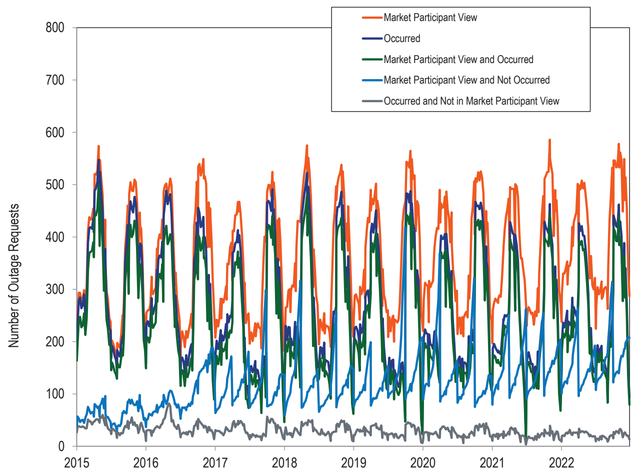


Figure 12-8, Figure 12-9, and Figure 12-10 show that on a weekly average basis, for the full year 2022, the active or approved outages for which information was available to day-ahead market participants, the outages included as inputs in the day-ahead market model and the outages that actually occurred in real time are not consistent. The average number of outages that actually occurred were 74.7 percent of the average number of outages for which information was available to market participants. The average number of outages included in the day-ahead market were 74.1 percent of the average number of outages for which information was available to market participants.

