Generation and Transmission Planning[1]

Overview

Generation Interconnection Planning

Existing Generation Mix

- As of March 31, 2025, PJM had a total installed capacity of 199,092.6 MW, of which 38,366.4 MW (19.3 percent) are coal fired steam units, 56,124.2 MW (28.2 percent) are combined cycle units and 33,452.6 MW (16.8 percent) are nuclear units. This measure of installed capacity differs from capacity market installed capacity because it includes energy only units, excludes all external units, and uses nameplate values for solar and wind resources.
- Of the 199,092.6 MW of installed capacity, 69,815.2 MW (35.1 percent) are from units older than 40 years, of which 30,814.3 MW (44.1 percent) are coal fired steam units, 191.0 MW (0.3 percent) are combined cycle units and 23,264.6 MW (33.3 percent) are nuclear units.

Generation Retirements[2]

- There are 62,810.2 MW of generation that have been, or are planned to be, retired between 2011 and 2028, of which 45,302.8 MW (72.1 percent) are coal fired steam units.
- In the first three months of 2025, 410.0 MW of generation retired. The largest generator that retired in the first three months of 2025 was the 410.0 MW Indian River 4 coal fired steam unit located in the DPL Zone. Of the 410.0 MW of generation that retired in the first three months of 2025, 410.0 MW (100.0 percent) were located in the DPL Zone.
- As of March 31, 2025, there are 7,654.9 MW of generation that have requested retirement after March 31, 2025, of which 2,700.0 MW (35.3 percent) are located in the AEP Zone. Of the generation requesting retirement in the AEP Zone, 2,620.0 MW (97.0 percent) are coal fired steam units.

1 Totals presented in this section include corrections to historical data and may not match totals presented in previous reports.
2 See PJM. Planning. "Generator Deactivations," (Accessed on March 31, 2025) <https://www.pjm.com/planning/service-requests/gen-deactivations>.

Generation Queue[3]

- On November 29, 2022, the Commission issued an order accepting PJM's tariff revisions to improve the queue process.[4] The new queue process includes modifications to implement a cluster/cycle based processing method to replace the first in/first out processing method.[5] 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 transition to the new queue process began on July 10, 2023.
- As of March 31, 2025, a total of 167,067.4 MW, on an energy basis, were in generation request queues in the status of active, under construction or suspended.[6] Based on historical completion rates, 33,489.2 MW (20.0 percent), on an energy basis, of new generation in the queue are expected to go into service. 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.
- Of the 7,664.8 MW, on an energy basis, of combined cycle projects in the queue, 4,194.3 MW (54.7 percent) are expected to go in service based on historical completion rates as of March 31, 2025.
- Of the 37,000.4 MW, on an energy basis, of battery projects in the queue, only 1,294.3 MW (3.5 percent) are expected to go in service based on historical completion rates as of March 31, 2025.
- Of the 120,350.5 MW, on an energy basis, of renewable projects in the queue, 26,775.4 MW (22.3 percent) are expected to go in service based on historical completion rates as of March 31, 2025.

3 See PJM. Planning. "New Services Queue," (Accessed on March 31, 2025) <https://www.pjm.com/planning/service-requests/serial-service-request-status>.
4 See 181 FERC ¶ 61,162 (2022).
5 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>.
6 Unless otherwise noted, the queue totals in this report are the winter net MW energy for the interconnection requests ("MW Energy") as shown in the queue.

- Of the 7,463.1 MW, on a capacity basis that requested CIRs, of combined cycle projects requested in the generation queues in the status of active, under construction or suspended, 3,987.1 MW (53.3 percent) are expected to go into service based on historical completion rates. Based on historical completion rates and the ELCC derate factors using the class ratings for the 2026/2027 Base Residual Auction,[7] the 7,463.1 MW of capacity requests currently under construction, suspended or active in the queue would be reduced to 2,943.8 MW of capacity (39.4 percent of the total requested capacity).[8]
- Of the 32,993.3 MW, on a capacity basis that requested CIRs, of battery projects requested in the generation queues in the status of active, under construction or suspended, 194.7 MW (0.6 percent) are expected to go into service based on historical completion rates. Based on historical completion rates and the ELCC derate factors using the class ratings for the 2026/2027 Base Residual Auction,[9] the 32,993.3 MW of capacity requests currently under construction, suspended or active in the queue would be reduced to 97.3 MW of capacity (0.3 percent of the total requested capacity).[10]
- Of the 65,103.4 MW, on a capacity basis that requested CIRs, of renewable projects requested in the generation queues in the status of active, under construction or suspended, 13,240.3 MW (20.3 percent) are expected to go into service based on historical completion rates. Based on historical completion rates and the ELCC derate factors using the class ratings for the 2026/2027 Base Residual Auction,[11] the 65,103.4 MW of capacity requests currently under construction, suspended or active in the queue would be reduced to 1,844.2 MW of capacity (2.8 percent of the total requested capacity).[12]
- As of March 31, 2025, 107,595.6 MW of capacity requests (requested CIRs) were in the generation queues in the status of active, under construction or suspended. Based on historical completion rates, 18,598.3 MW (17.3 percent) are expected to go into service. Based on historical completion rates and the ELCC derate factors using the class ratings for the 2026/2027 Base Residual Auction, the 107,595.6 MW of capacity requests currently under construction, suspended or active in the queue would be reduced to 5,610.6 MW of capacity (5.2 percent of the total requested capacity).
- As of March 31, 2025, 8,190 projects, representing 824,096.3 MW, have entered the queue process since its inception in 1998. Of those, 1,244 projects, representing 93,129.4 MW (11.3 percent of the MW), went into service. Of the projects that entered the queue process, 4,915 projects, representing 563,899.4 MW (68.4 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.
- In the first three months of 2025, 994.8 MW from the queue went into service. Of the 994.8 MW that went in service, 994.8 MW (100.0 percent) were solar units.
- The number of queue entries increased during the past several years, primarily renewable projects. Of the 5,538 projects that entered the queue from January 1, 2015, through March 31, 2025, 4,111 projects (74.2 percent) were renewable. Of the 467 projects that entered the queue in 2023, 414 projects (88.7 percent) were renewable. Renewable projects make up 77.5 percent of all projects in the queue and account for 72.0 percent of the nameplate MW currently active, suspended or under construction in the queue as of March 31, 2025.
- On March 31, 2025, 37,335.2 MW, on an energy basis, were in generation request queues that had reached the construction service agreement milestone or equivalent, in the status of active, suspended or under construction. Of the 37,335.2 MW, 18,572.4 MW (49.7 percent) had not begun construction, 11,219.6 MW (30.0 percent) had begun construction, but are now suspended, and 7,563.2 MW (20.3 percent) are currently under

7 *ELCC Class Ratings for 2026/2027 Base Residual Auction*, PJM Interconnection L.L.C. (February 28, 2025) <https://www.pjm.com/-/media/DotCom/planning/res-adeq/elcc/2026-27-bra-elcc-class-ratings.pdf>.

8 The 2026/2027 Base Residual Auction ELCC factors are used for the ELCC derate adjusted MW. The adjusted MW are calculated using the four hour storage ELCC derate for battery resources, tracking solar for solar resources and onshore wind for wind resources.

9 *ELCC Class Ratings for 2026/2027 Base Residual Auction*, PJM Interconnection L.L.C. (February 28, 2025) <https://www.pjm.com/-/media/DotCom/planning/res-adeq/elcc/2026-27-bra-elcc-class-ratings.pdf>.

10 The 2026/2027 Base Residual Auction ELCC factors are used for the ELCC derate adjusted MW. The adjusted MW are calculated using the four hour storage ELCC derate for battery resources, tracking solar for solar resources and onshore wind for wind resources.

11 *ELCC Class Ratings for 2026/2027 Base Residual Auction*, PJM Interconnection L.L.C. (January 23, 2025) <https://www.pjm.com/-/media/DotCom/planning/res-adeq/elcc/2026-27-bra-elcc-class-ratings.pdf>.

12 The 2026/2027 Base Residual Auction ELCC factors are used for the ELCC derate adjusted MW. The adjusted MW are calculated using the four hour storage ELCC derate for battery resources, tracking solar for solar resources and onshore wind for wind resources.

construction. Reaching the final milestone required prior to construction does not mean a project will immediately begin construction or even that it necessarily will ever begin construction.

Regional Transmission Expansion Plan (RTEP)

Market Efficiency Process

- There are significant issues with PJM's benefit/cost analysis that should be addressed prior to approval of additional projects. If done correctly and if FTRs/ARRs returned 100 percent of congestion to load, the benefit/cost analysis would include the total net change in production costs and would not include congestion. In addition, PJM's benefit/cost analysis includes only the decreases in costs to load and ignores the increases in costs to load associated with market efficiency projects.
- Through March 31, 2025, PJM has completed five market efficiency cycles under Order No. 1000.[13] PJM delayed the opening of the 2022/2023 Long-Term Window until the reliability violations for the 2022 Window 3 were addressed. In January 2024, PJM completed updating the 2022/2023 market efficiency base case to include the solution selected from the 2022 Window 3. No flowgates experienced historical congestion that required an open window. PJM will continue to analyze the congestion patterns as part of the 2024/25 Market Efficiency cycle. In February 2024, PJM completed the 2024/2025 market efficiency base case. In May 2024, PJM posted the 2024/2025 Market Efficiency planning assumptions. PJM posted an updated 2024/2025 base case in July 2024, and requested stakeholder feedback by August 31, 2024. PJM is currently preparing the final base case, sensitivity scenarios and congestion drivers. The long term market efficiency window is expected to open on April 11, 2025 and close on June 10, 2025.

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.

  The simultaneous use for joint projects of an incorrectly defined benefit/cost 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 a correctly defined benefit/cost 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.

PJM MISO Interregional Transfer Capability Study (ITCS)

- PJM and MISO developed the Interregional Transfer Capability Study (ITCS) to help identify potential transmission projects that could incrementally improve the systems' ability to mitigate constraints, improve market efficiency, respond to extreme weather and increase interregional transfer capability.

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

13 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).

criteria, as determined by PJM."[14] Supplemental projects are exempt from competition.

- The average number of supplemental projects in each expected in service year increased by 1,155.0 percent, from 20 for years 1998 through 2007 (pre Order No. 890) to 251 for years 2008 through 2025 (post Order 890).[15]

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 require competition to build the project. Under the current approach, end of life projects are excluded from the RTEP process and exempt from competition.

Board Authorized Transmission Upgrades

- The Transmission Expansion Advisory Committee (TEAC) reviews proposals to improve transmission reliability in PJM and between PJM and neighboring regions. 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.[16] In the first three months of 2025, the PJM Board approved $7.73 billion in upgrades. As of March 31, 2025, the PJM Board has approved $57.8 billion in system enhancements since 1999.

Transmission Competition

- The MMU makes several recommendations related to the competitive transmission planning process. The recommendations include improved process transparency, incorporation of competition between transmission and generation alternatives, and the removal of barriers to competition from nonincumbent transmission. These recommendations would help ensure that the process is an open and transparent process that results in the most competitive solutions.

- On May 24, 2018, the PJM Markets and Reliability Committee (MRC) approved a motion that required PJM, with input from the MMU, to develop a comparative framework to evaluate the quality and effectiveness of competitive transmission proposals with binding cost containment proposals compared to proposals from incumbent and nonincumbent transmission companies without cost containment provisions.

Qualifying Transmission Upgrades (QTU)

- A Qualifying Transmission Upgrade (QTU) is an upgrade to the transmission system, financed and built by market participants, that increases the Capacity Emergency Transfer Limit (CETL) into an LDA and can be offered into capacity auctions as capacity. Once a QTU is in service, the upgrade is eligible to continue to offer the approved incremental import capability into future RPM Auctions. As of March 31, 2025, no QTUs have cleared a Base Residual Auction or an Incremental Auction.

Transmission Facility Outages

- PJM maintains a list of reportable transmission facilities. When a reportable transmission facility needs 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.[17]

- There were 15,975 transmission outage requests submitted in the first 10 months of the 2024/2025 planning period. Of the requested outages, 73.9 percent were planned for less than or equal to five days and 10.3 percent were planned for greater than 30 days. Of the requested outages, 41.3 percent were late according to the rules in PJM's Manual 3.

14 See PJM. "Transmission Construction Status," (Accessed on March 31, 2025) <https://www.pjm.com/planning/m/project-construction>.
15 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).
16 Supplemental Projects, including the end of life subset of supplemental projects, do not require PJM Board of Managers authorization.
17 See "PJM Manual 03: Transmission Operations," Rev. 67 (November 21, 2024).

Recommendations

Generation Retirements

- The MMU recommends that CIRs should end on the date of retirement in order to help ensure competitive markets and competitive access to the grid. The rules need to ensure that incumbents cannot exploit control of CIRs to block or postpone entry of competitors or to exercise market power by requiring high payments for CIRs.[18] (Priority: Medium. First reported 2013. Status: Partially adopted, 2012.)

Generation Queue

- Given the significance of data to market participants and regulators, the MMU recommends that all queue data and supplemental, network and baseline project data, including projected in service dates and estimated and final costs, be regularly updated with accurate and verifiable data. PJM does not update this data. (Priority: High. First reported 2023. Not adopted.)
- 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 that PJM establish an expedited PJM managed queue process to identify commercially viable projects that could help eliminate or reduce the need for specific RMRs or that could address specific reliability needs and allow the identified projects to advance in the queue ahead of projects which have failed to make progress, subject to rules to prevent gaming. (Priority: High. First reported Q2, 2024. 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 an expedited 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.[19] (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.[20] (Priority: Medium. First reported 2014. Status: Partially adopted.)
- The MMU recommends outsourcing interconnection studies to an independent party to avoid potential conflicts of interest. Currently, these studies are performed by incumbent transmission owners under PJM's direction. This creates potential conflicts of interest, particularly when transmission owners are vertically integrated and the owner of transmission also owns generation. (Priority: Low. First reported 2013. Status: Not adopted.)

Market Efficiency Process

- The MMU recommends that the market efficiency process be eliminated because it is not consistent with a competitive market design. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that, if the market efficiency process is retained, PJM modify the rules governing benefit/cost analysis, the evaluation process for selecting among competing market efficiency projects and cost allocation for economic projects in order to ensure that all changes in production costs but not congestion costs, including increased costs to load 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. The MMU also recommends that, if the market efficiency process is retained, market efficiency projects that fail to meet PJM benefit/cost criteria in a Schedule 6 annual reevaluation, prior to construction commencing or prior to state

18 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>.

19 PJM Filing, FERC Docket No. ER22-2110-000 (June 14, 2022); 181 FERC ¶ 61,162 (2022).

20 Ibid.

approval, be canceled and removed from further consideration. (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 require competition to build such projects or to effectively replace the RTEP process. (Priority: Medium. First reported 2017. Status: Not adopted. Rejected by FERC.)[21]
- 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 require competition to build such projects. (Priority: Medium. First reported 2019. Status: Not adopted. Rejected by FERC.)[22]
- 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 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 require 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 require competition to provide financing for transmission projects. This competition could reduce the cost of capital for transmission projects and significantly reduce total costs to customers. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that storage resources not be includable as transmission assets for any reason. (Priority: High. First reported 2020. Status: Not adopted.)

Cost Allocation

- The MMU recommends a comprehensive review of the ways in which the solution based dfax allocation method 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

21 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).

22 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), *affirmed*, American Municipal Power, Inc., et al. v. FERC, Case No. 20-1449 (D.C. Cir. November 17, 2023), 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).

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 transmission facilities.[23] (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: Partially adopted.)
- The MMU recommends that all PJM transmission owners investigate the applicability and potential cost savings of Grid Enhancing Technology (GET) and that all PJM transmission owners implement cost effective GET, subject to NERC standards and guidelines, subject to review by NERC, PJM and the MMU, and approval by FERC. (Priority: Medium. First reported Q2, 2024. Status: Not adopted.)
- The MMU recommends that the implementation of Grid Enhancing Technology (GET) be opened to competition from third parties, subject to NERC standards and guidelines, subject to review by NERC, PJM and the MMU, and approval by FERC. (Priority: Medium. First reported Q3, 2024. 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, create options for late requests based on the reasons, and apply the modified rules for late submissions to any such outages. The MMU recommends that PJM create options for treatment of late outages. The current rules apply more stringent rules, based on controlling actions, to late outages without distinguishing among reasons for late outages. (Priority: Low. First reported 2014. Status: Not adopted.)
- The MMU recommends that PJM draft a definition of the economic and physical congestion analysis required for transmission outage requests and associated triggers, including both the extent of overloaded facilities and the level of economic congestion, to include in PJM manuals after appropriate review with appropriate rules for on time and late outage requests. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM create options for late requests based on the reasons, and modify the rules to reduce or eliminate the approval of late outage requests submitted or rescheduled after the FTR auction bidding opening date, based on those options. (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 the PJM market design should be to enhance competition and to ensure that competition is the core element of all PJM markets. 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. 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 require 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

23 See *2015 State of the Market Report for PJM*, Volume 2,, Section 12: Generation and Transmission Planning, at 463, Cost Allocation Issues.

modify those directives. It remains the recommendation of the MMU that the PJM rules for competitive transmission development through the RTEP should build upon FERC Order No. 1000 to create real competition between incumbent transmission providers and nonincumbent transmission providers. The ability of transmission owners to block competition for supplemental projects and end of life projects and the reasons for that policy should be reevaluated. PJM should enhance the transparency and queue management process for nonincumbent transmission investment. Issues related to data access and complete explanations of cost impacts should be addressed. The goal should be to remove barriers to competition from nonincumbent transmission.

Order No. 1000 removed the right of first refusal (ROFR) for transmission projects for incumbent transmission owners except for the case of supplemental projects. This created an incentive for incumbent transmission owners to designate projects as supplemental projects to avoid the Order No. 1000 competitive provisions. Two PJM states, Indiana and Michigan, have passed laws that provide ROFR to incumbent utilities/transmission owners.[24] [25]

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. All PJM Transmission Owners should be required to immediately adopt current dynamic line rating (DLR) methods for all transmission facilities, subject to NERC standards and guidelines, subject to review by NERC, PJM and the MMU, and approval by FERC.

24 See IN Code § 8-1-38-9, effective 7/1/2023. Applies to transmission facilities approved for construction through an RTO planning process. Incumbent Transmission Owner must exercise within 90 days.
25 See MCL §460.593, effective 12/17/2021. Applies to regionally cost shared transmission lines included in a plan adopted by a recognized planning authority. Must be exercised by the incumbent (s) within 90 days after plan is adopted/approved.

Given the slow pace of adoption by Transmission Owners of Grid Enhancing Technologies (GETs), PJM and the Commission should introduce rules that would allow third parties to propose adding GETs to the transmission system, subject to NERC standards and guidelines, subject to review by NERC, PJM and the MMU, and approval by FERC. The third parties would be compensated in the same way that TOs would be compensated for comparable investments.

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 require competition to build the project. If there is no defined need for 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.[26] [27] 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

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

not expected to reach commercial operation. The new process should help to reduce backlog and to remove projects that are not viable earlier to help improve the overall efficiency of the queue process.

While the changes in the queue process will clearly improve the process, the MMU's recommendations related to the queue process will remain until the new process is in place and it can be evaluated. 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.

On January 31, 2025, PJM submitted revisions to the PJM Tariff to expedite the transfer of CIRs from deactivating generating resources to new replacement resources.[28] The suggestion that generation owners should be permitted to avoid the queue process and directly transfer the generation CIRs to an affiliate or directly sell the CIRs to an unaffiliated entity should be rejected.[29][30] This proposed approach is about creating a process to maximize the value of existing CIRs to incumbent generators and not about facilitating the efficient replacement of retiring resources. In effect, this approach, if adopted by the large number of retiring units, would create a chaotic, bilateral private queue process that would create market power and facilitate the exercise of market power in the sale of CIRs by incumbent generators. In effect the proposed approach would replace a significant part of the recently redesigned PJM queue process. The proposed continuation of retention of CIRs by incumbent generators creates the potential for delays of up to a year and the proponents have proposed the option to request further delays. This approach would inappropriately delegate the authority from PJM to the incumbent generator to choose the new resource based on highest offer for CIRs rather than based on PJM defined system reliability needs. There would be no requirement to even be a capacity resource and there would be no requirement to offer the capacity into the capacity market. After the entire process, the contribution to PJM reliability could be zero. PJM's recently proposed expedited process for addressing reliability needs (RRI) is preferable and should be considered as the preferred alternative to the proposed approach from the Planning Committee stakeholder process.

The MMU recommends that PJM establish an expedited PJM managed queue process to identify commercially viable projects that could help eliminate or reduce the need for specific RMRs or that could address specific reliability needs and allow the identified projects to advance in the queue ahead of

28 See PJM Interconnection, L.L.C., Docket No. ER25-1128 (January 31, 2025).

29 See PJM. "*Enhancing Capacity Interconnection Rights (CIR) Transfer Efficiency: Problem / Opportunity Statement*," <https://www.pjm.com/-/media/committees-groups/subcommittees/ips/2023/20230731/20230731-item-08b---enhancing-capacity-interconnection-rights---cir---transfer-efficiency-problem-statement.ashx>.

30 On April 30, 2024, the CIR Transfer Efficiency issue was transferred from the Interconnection Process Subcommittee (IPS) to the Planning Committee (PC).

projects which have failed to make progress, subject to rules to prevent gaming. Rules should be developed to permit PJM to advance projects in the queue if they would resolve immediate reliability issues that result, for example, from unit retirements. The rules should be consistent with the flexibility included in the new queue process but add the option for PJM to expedite the interconnection and commercial operation of projects in the queue that would address identified reliability issues, consistent with the standing of the projects in the queue.

The PJM queue process should continue to define available and needed CIRs for all capacity queue projects. CIRs from retiring units should be made available to the next resource in the queue that can use them, on the retirement date of the retiring resource. Generation owners do not have property rights in CIRs. The value of CIRs is a result of the entire transmission system which has been paid for by customers and other generators. The value of CIRs is a result of the existence of a network and is not a result solely or even primarily of the investment that may or may not have been required in order to get CIRs. The cost of CIRs is part of project costs included in generation owners' investment decisions like any other project cost and subject to the same risk and reward structure. Open access to the transmission system by new resources should not be limited by claims to own the access rights by retiring units. In addition, the proposal to bypass the PJM interconnection process with a private, bilateral process ignores the fact that if the new resource is a renewable resource or a storage resource, the new resource does not have a capacity market must offer requirement. The PJM interconnection process could be bypassed, CIRs transferred and then the resource does not offer into the capacity market. In that case, scarce CIRs will be withheld by a generator who does not provide capacity and customers have to pay for an additional capacity resource instead.

The fundamental purpose of the queue process is to provide open access to the grid for supply resources. More specifically, the fundamental purpose of the queue process for capacity resources is to provide open access to the grid and to ensure that the energy from capacity resources is deliverable so that capacity resources can meet their must offer obligations in the energy market and provide reliable energy supply during all conditions. In order to ensure that open access, all capacity resources should be required to have a must offer obligation in the capacity market. If they do not, such resources are effectively withholding access to the grid from capacity resources that would take on a must offer obligation in the capacity market. The result creates market power for the resources with no must offer obligation, noncompetitively limits access to the grid, increases capacity market prices above the competitive level, and creates uncertainty and unpredictable volatility in the capacity market.

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

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

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

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

The benefit/cost analysis should also account for the fact that the transmission project costs are not subject to cost caps and may exceed the estimated costs by a wide margin. When actual costs exceed estimated costs, the benefit/cost 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 benefit/cost 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 and expanded definition of the congestion analysis required for transmission outage requests that is incorporated in the PJM Market Rules. PJM Manual 38 currently defines congestion resulting from a transmission outage as an overload on transmission facilities rather than using the general economic definition of congestion resulting from out of merit generation to control constraints. PJM does not currently evaluate the economic impact of congestion when reviewing proposed transmission outages.[31]

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.

As an example of the complexities of defining the benefits of transmission investments, the reduction in congestion is frequently and incorrectly cited as a metric of benefits. Congestion is frequently misunderstood. Congestion is not static. Congestion exhibits dynamic intertemporal variability and dynamic locational variability. More importantly, congestion is not the correct metric for evaluating the potential benefits of enhancing the transmission grid. The correct metric is the total net change in production costs.

There is not a secular trend towards increasing congestion in PJM. Congestion is volatile on a monthly basis. Congestion is also volatile on an hourly and daily basis. For example, higher congestion can result from changes in seasonal and daily/hourly fuel costs.

The level and distribution of congestion at a point in time is a function of the location and size of generating units, the relative costs of the fuels burned and the associated marginal costs of generating units, the location and size of load and the locational capability of the transmission grid. Each of these factors changes over time.

The geographic distribution of congestion is dynamic. The nature and location of congestion in the PJM system has changed significantly over the last 10 years and continues to change. The nature and location of congestion in PJM

31 PJM, "Manual 38: Operations Planning," Rev. 19 (January 23, 2025) at 19-20.

can also change from one day to the next as a result of changes in relative fuel costs. As a result, building transmission to address a specific pattern of congestion does not make sense, unless the technology can be easily moved to new locations as conditions change. The transmission system is only one of many reasons that congestion exists. The dynamic nature of congestion and the multiple, interactive causes of congestion make it virtually impossible to identify the standalone impacts of an individual transmission investment on future congestion. It is possible, for example, that congestion occurring during a period of a few days in the winter as a result of very high fuel prices, significantly increases the reported level of congestion for the entire year. This has occurred in PJM. It would be a mistake to consider that level of congestion to be a signal to build transmission.

At a more fundamental level, congestion is not the correct metric for evaluating the potential benefits of enhancing the transmission grid. When there are binding transmission constraints and locational price differences, load pays more for energy than generation is paid to produce that energy. The difference is congestion. Congestion is neither good nor bad, but is a direct measure of the extent to which there are multiple marginal generating units with different offers dispatched to serve load as a result of transmission constraints. Congestion occurs when available, least-cost energy cannot be delivered to all load because transmission facilities are not adequate to deliver that energy to one or more areas, and higher cost units in the constrained area(s) must be dispatched to meet the load. The result is that the price of energy in the constrained area(s) is higher than in the unconstrained area. Load in the constrained area pays the higher price for all energy including energy from low cost generation and energy from high cost generation, while only high cost generators are paid the high price at their bus and low cost generators are paid only the low price at their bus.

If FTRs worked perfectly and were assigned directly to load, FTRs would return all congestion to the load that paid the congestion. Congestion is not a cost, it is an accounting result of a market based on locational energy prices in which all load in a constrained area pays the higher single market clearing locational price, resulting in excess payments by load that are not paid to generation, which should be returned to load.

Counterintuitively, congestion actually increases when the transmission capacity between areas with lower cost generation and areas with higher cost generation increases but does not fully eliminate the need for some higher cost local generation. The smaller the amount of higher cost local generation needed to meet load, the more of the local load is met via low cost generation delivered over the transmission system and therefore the higher is the difference between what load pays and generation receives, congestion.

For all these reasons, if done correctly and if FTRs/ARRs returned 100 percent of congestion to load, the benefit/cost analysis for transmission projects would include the total net change in production costs and would not include congestion. The change in production costs correctly measures the changes in cost to load that result from a project.

The PJM Regional Transmission Expansion Plan (RTEP) successfully addresses the need for transmission investment to reliably meet load. Together with the requirement that new generation pay interconnection costs, the RTEP process has resulted in the appropriate level of new transmission investment in PJM. There is no evidence that the PJM planning process is not adequate to meet the requirements of the PJM markets. Additional transmission investment is not a panacea. Transmission investment is expensive and long lived and it is essential that transmission investments be carefully planned for clearly identified needs in order to ensure that power markets can continue to provide reliable service at a competitive price.

PJM must make out of market payments to units that want to retire (deactivate) but that PJM requires to remain in service, for limited operation, for a defined period because the unit is needed for reliability.[32] This provision has been known as Reliability Must Run (RMR) service but RMR is not defined in the PJM tariff. The correct term is Part V reliability service. The need to retain uneconomic units in service reflects a flawed market design and/or planning process problems. If a unit is needed for reliability, the market should

32 OATT Part V §114.

reflect a locational value consistent with that need which would result in the unit remaining in service or being replaced by a competitor unit. The planning process should evaluate the impact of the loss of units at risk and determine in advance whether transmission upgrades are required in order to limit the duration of Part V service for individual units. It is essential that the deactivation provisions of the tariff be evaluated and modified. It is also essential that PJM look forward and attempt to plan for foreseeable unit retirements, whether for economic or regulatory reasons. PJM should consider an expedited queue process for projects that could replace the retiring capacity including the immediate transfer of the retiring unit's CIRs to units in the queue in order to permit generation to compete as an alternative to the current transmission only approach.

An area in northern Virginia in the Dominion Transmission Zone, known as Data Center Alley, has experienced significant load growth from data centers. 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 identified the need for additional baseline reinforcements to support the load growth. These baseline reinforcements were addressed in the 2022 RTEP Window 3, when the PJM board approved $1.4 billion of necessary baseline upgrades specific to the Data Center Alley reinforcements.[33] These regional transmission costs were allocated according to Schedule 12 of PJM's Open Access Transmission Tariff (OATT), where costs are shared across all zones by a combination of load ratio share and distribution factor impacts. The transmission owners include these project costs in their base case, and all retail customers in the PJM footprint pay for those upgrade costs through increased energy bills. The cost allocation of the $1.4 billion in baseline upgrades are assigned to all retail customers and not solely to the customers requesting interconnection.

The high level of customer requests in Data Center Alley resulted in the need for significant baseline reliability upgrades. These costs were allocated per Schedule 12 of the PJM OATT. Not all customer requests result in reliability upgrades. Transmission upgrades for customer requests that are submitted through the supplemental planning process are allocated 100 percent to the zone where they are interconnecting. The transmission owner of that zone then includes those project costs in their rate base, and all retail customers in that zone pay those costs.

The main focus of PJM's planning requirements has been to ensure adequate transmission to allow for generation to reliably serve load. Historically, PJM has had enough excess generation to serve the forecasted load in the RTEP process. In recent years, due in part to the significant increase in load resulting from large load interconnection requests and an increase in thermal unit deactivations, meeting forecasted loads and reserves with existing generation has become an issue. In order to solve the RTEP study cases, PJM must make assumptions about the existing and future generation to include in the RTEP model based on the need to serve load. The RTEP analysis first includes all existing generation that is expected to remain in service for the year being studied. When the forecasted load exceeds the expected in service generation, the RTEP analysis includes future generation. Planned generators with a signed interconnection service agreement (ISA) or generation interconnection agreement (GIA), or that cleared a BRA, are included. When the PJM load in the RTEP analysis exceeds the sum of existing generation and generation with an executed final agreement, the RTEP analysis adds speculative new generation that is in its Phase 3 system impact study status to meet the load. If needed, additional generation (pre-GIA stage or with a suspended status) may be modeled consistent with the procedures noted in Manual 14B.[34] [35] The RTEP analysis is not adequately coordinated with PJM markets analysis including the energy and capacity markets.

33 See "*Transmission Expansion Advisory Committee (TEAC) Recommendations to the PJM Board*," December 2023. <https://www.pjm.com/-/media/committees-groups/committees/teac/2023/20231205/20231205-pjm-teac-board-whitepaper-december-2023.ashx>.

34 See "Review of 2025 RTEP Assumptions," presented at the January 7, 2025 meeting of the Transmission Expansion Advisory Committee. <https://www.pjm.com/-/media/DotCom/committees-groups/committees/teac/2025/20250107/20250107-item-11---2025-rtep-assumption.pdf>.

35 See "PJM Manual 14B: PJM Region Transmission Planning Process," Rev. 57 (September 25, 2024).

Generation Interconnection Planning

Existing Generation Mix

Table 12-1 shows the existing PJM capacity by control zone and unit type.[36] [37] As of March 31, 2025, PJM had an installed capacity of 199,092.6 MW, of which 38,366.4 MW (19.3 percent) are coal fired steam units, 56,124.2 MW (28.2 percent) are combined cycle units and 33,452.6 MW (16.8 percent) are nuclear units. This measure of installed capacity differs from capacity market installed capacity because it includes energy only units, external units and uses nameplate values for solar and wind resources.

The AEP Zone has the most installed capacity of any PJM zone. Of the 199,092.6 MW of PJM installed capacity, 37,354.3 MW (18.8 percent) are in the AEP Zone, of which 13,463.0 MW (36.0 percent) are coal fired steam units, 9,294.0 MW (24.9 percent) are combined cycle units and 2,071.0 MW (5.5 percent) are nuclear units.

Table 12-1 Existing capacity: March 31, 2025 (By zone and unit type (MW))[38]

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	395.5	0.0	0.0	1.6	0.0	0.0	0.0	0.0	4.0	5.4	69.7	0.0	0.0	0.0	0.0	0.0	0.0	7.5	0.0	1,265.2
AEP	0.0	9,294.0	4,108.2	16.2	4.8	0.0	66.0	420.9	2,071.0	0.0	0.0	20.4	3,650.9	0.0	0.0	13,463.0	738.0	0.0	0.0	3,500.9	0.0	37,354.3
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	60.4	2,843.7	1,223.3	0.0	2.0	0.0	0.0	129.2	0.0	22.4	0.0	18.3	381.0	0.0	0.0	5,119.0	0.0	0.0	0.0	1,040.0	0.0	10,839.3
ATSI	0.0	4,647.5	1,383.0	183.0	6.4	0.0	0.0	0.0	2,134.0	0.0	5.5	5.6	483.0	0.0	0.0	0.0	325.0	0.0	136.0	0.0	0.0	9,309.0
BGE	3.5	0.0	267.6	228.8	0.0	0.0	0.0	0.0	1,716.0	0.0	0.0	4.2	31.1	0.0	0.0	1,273.0	143.5	702.0	57.0	0.0	0.0	4,426.7
COMED	104.5	4,631.1	7,053.3	226.2	0.0	0.0	0.0	0.0	10,473.5	0.0	0.0	15.0	59.0	0.0	0.0	2,646.0	0.0	0.0	0.0	5,433.2	0.0	30,641.8
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	692.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,624.4
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	289.9	0.0	0.0	1,252.0	47.0	0.0	0.0	0.0	0.0	2,899.9
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	54.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,172.9
DOM	20.0	9,138.0	3,835.3	256.4	10.0	0.0	3,003.0	586.3	3,581.3	0.0	18.0	94.7	4,826.9	0.0	0.0	2,473.2	55.0	0.0	318.4	776.0	0.0	28,992.5
DPL	0.0	1,742.5	978.2	478.2	0.0	30.0	0.0	0.0	0.0	0.0	22.0	14.1	470.9	0.0	0.0	0.0	710.0	153.0	70.0	0.0	0.0	4,668.9
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	105.0	0.0	0.0	1,687.0	0.0	0.0	0.0	0.0	0.0	2,702.0
JCPLC	112.8	2,115.5	531.1	0.0	0.0	0.4	140.0	0.0	0.0	0.0	0.0	14.1	416.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3,330.1
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	430.0	0.0	0.0	80.0	35.0	0.0	60.0	0.0	0.0	3,650.4
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	422.1	57.0	0.0	0.0	513.0	77.8	0.0	120.1	28.0	11.0	288.6	0.0	0.0	4,169.5	610.0	0.0	42.0	1,238.0	0.0	9,505.5
PEPCO	0.0	1,736.5	770.2	150.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8.7	35.6	0.0	0.0	0.0	1,164.1	0.0	52.0	0.0	0.0	3,917.1
PPL	20.0	5,558.5	234.0	36.0	20.6	0.0	0.0	706.6	2,520.0	12.0	5.0	14.7	75.0	0.0	0.0	1,859.9	3,137.0	0.0	29.0	216.5	0.0	14,444.8
PSEG	7.7	4,223.1	963.2	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	9,113.3
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	100.0	0.0	3,865.6
Total	375.3	56,124.2	25,107.1	2,929.3	43.8	32.0	4,792.0	2,771.1	33,452.6	168.9	118.5	271.8	12,593.1	0.0	0.0	38,366.4	7,732.9	855.0	1,046.5	12,312.1	0.0	199,092.6

36 The unit type RICE refers to Reciprocating Internal Combustion Engines.
37 XIC refers to external installed capacity.
38 The capacity described in this section refers to all capacity in PJM at the summer installed capacity rating, regardless of whether the capacity entered the RPM Auction.

Table 12-2 shows the installed capacity by state for each fuel type. Pennsylvania has the most installed capacity of any PJM state. Of the 199,092.8 MW of installed capacity, 47,303.6 MW (23.8 percent) are in Pennsylvania, of which 6,109.4 MW (12.9 percent) are coal fired steam units, 18,292.2 MW (38.7 percent) are combined cycle units and 8,843.8 MW (18.7 percent) are nuclear units.

Table 12-2 Existing capacity: March 31, 2025 (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	6.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	25.5
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	50.0	0.0	0.0	0.0	710.0	0.0	70.0	0.0	0.0	2,052.4
IL	104.5	4,631.1	7,053.3	226.2	0.0	0.0	0.0	0.0	10,473.5	0.0	0.0	15.0	59.0	0.0	0.0	2,646.0	0.0	0.0	0.0	5,433.2	0.0	30,641.8
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	982.6	0.0	0.0	3,923.8	0.0	0.0	0.0	2,353.2	0.0	9,547.4
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	282.0	0.0	0.0	1,687.0	278.0	0.0	0.0	0.0	0.0	4,001.1
MD	3.5	2,717.0	1,684.5	394.7	0.0	0.0	0.0	0.0	1,716.0	0.0	10.0	18.9	536.8	0.0	0.0	1,273.0	1,307.6	855.0	191.0	349.9	0.0	11,057.9
MI	0.0	994.0	0.0	0.0	4.8	0.0	0.0	11.8	2,071.0	0.0	0.0	3.2	4.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3,089.4
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	1,181.5	0.0	0.0	0.0	0.0	0.0	0.0	397.0	0.0	2,076.5
NJ	120.5	7,120.2	1,889.8	0.0	0.0	2.0	140.0	5.0	3,493.0	0.0	4.0	28.5	716.1	0.0	0.0	0.0	3.0	0.0	179.1	7.5	0.0	13,708.6
OH	18.0	10,634.7	4,626.2	255.2	6.4	0.0	0.0	200.0	2,134.0	0.0	34.0	10.4	3,611.6	0.0	0.0	6,820.0	47.0	0.0	136.0	1,147.7	0.0	29,681.1
PA	49.9	18,292.2	1,545.5	1,334.5	20.6	0.0	1,583.0	1,445.7	8,843.8	168.9	40.5	75.8	967.6	0.0	0.0	6,109.4	4,872.3	0.0	234.0	1,719.9	0.0	47,303.6
TN	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
VA	20.0	8,973.0	4,172.3	591.4	12.0	0.0	3,069.0	460.1	3,581.3	0.0	12.0	100.7	4,081.4	0.0	0.0	1,468.2	515.0	0.0	236.4	12.0	0.0	27,304.8
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	120.0	0.0	0.0	12,484.0	0.0	0.0	0.0	791.7	0.0	14,736.8
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	100.0	0.0	3,865.6
Total	375.3	56,124.2	25,107.1	2,929.3	43.8	32.0	4,792.0	2,771.1	33,452.6	168.9	118.5	271.8	12,593.1	0.0	0.0	38,366.4	7,732.9	855.0	1,046.5	12,312.1	0.0	199,092.6

Table 12-3 and Figure 12-1 show the age of existing PJM generators, by unit type, as of March 31, 2025. Of the 199,092.6 MW of installed capacity, 69,815.2 MW (35.1 percent) are from units older than 40 years, of which 30,814.3 MW (44.1 percent) are coal fired steam units, 191.0 MW (0.3 percent) are combined cycle units and 23,264.6 MW (33.3 percent) are nuclear units.

Table 12-3 Capacity (MW) by unit type and age (years): March 31, 2025

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	375.3	36,892.9	2,349.8	0.0	43.8	32.0	0.0	293.6	0.0	134.5	2.0	151.2	12,593.1	0.0	0.0	2,440.0	82.0	0.0	47.4	12,127.6	0.0	67,565.1
20 to 40	0.0	19,040.3	22,454.8	478.0	0.0	0.0	3,003.0	280.9	10,188.0	34.4	22.0	104.8	0.0	0.0	0.0	5,112.1	73.3	0.0	736.1	184.5	0.0	61,712.2
40 to 60	0.0	191.0	302.5	2,433.6	0.0	0.0	1,789.0	219.5	23,264.6	0.0	76.5	15.8	0.0	0.0	0.0	28,309.5	5,375.1	855.0	57.0	0.0	0.0	62,889.1
Greater than 60	0.0	0.0	0.0	17.7	0.0	0.0	0.0	1,977.1	0.0	0.0	18.0	0.0	0.0	0.0	0.0	2,504.8	2,202.5	0.0	206.0	0.0	0.0	6,926.1
Total	375.3	56,124.2	25,107.1	2,929.3	43.8	32.0	4,792.0	2,771.1	33,452.6	168.9	118.5	271.8	12,593.1	0.0	0.0	38,366.4	7,732.9	855.0	1,046.5	12,312.1	0.0	199,092.6

Figure 12-1 Capacity (MW) by age (years): March 31, 2025

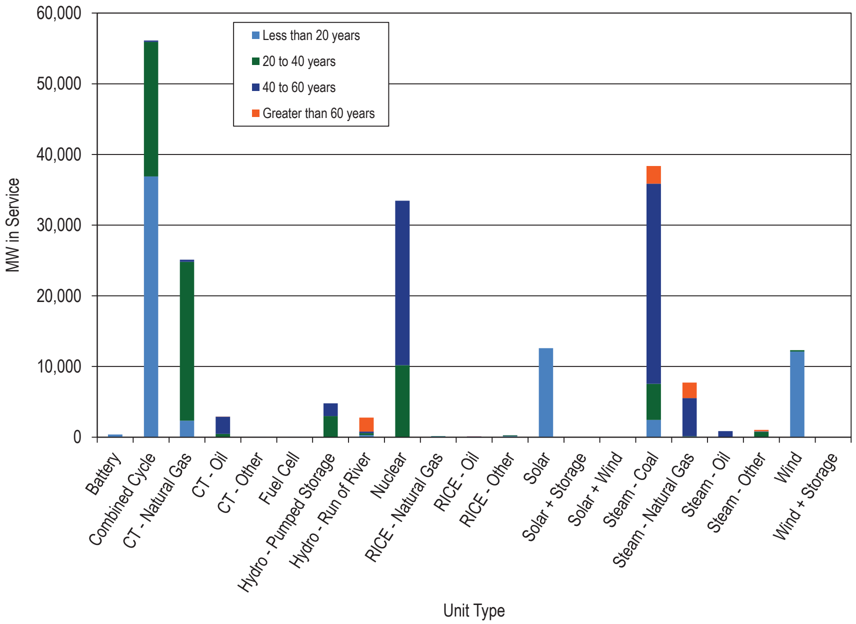


Figure 12-2 is a map of units, less than 20 MW in size that came online between January 1, 2011, and Mach 31, 2025. A mapping to these unit names is in Table 12-4.

Figure 12-2 Map of unit additions (less than 20 MW): January 1, 2011 through March 31, 2025

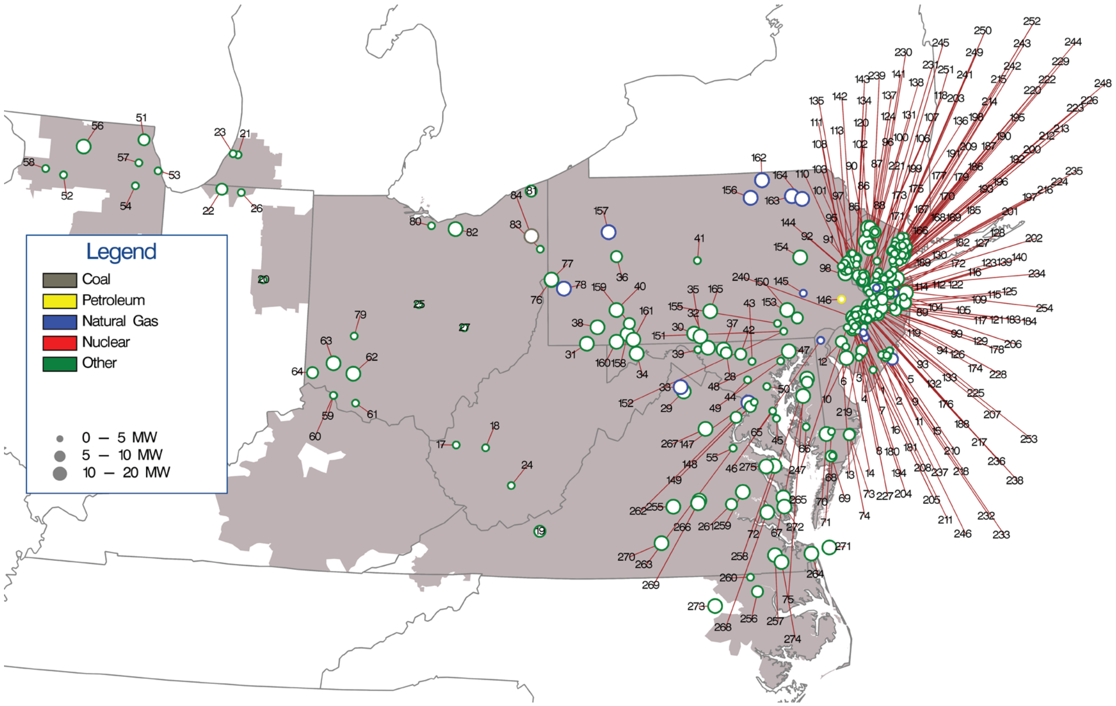


Table 12-4 Unit identification for map of unit additions (less than 20 MW): January 1, 2011 through March 31, 2025

ID	Unit	ID	Unit	ID	Unit	ID	Unit	ID	Unit
1	ACE CAPE MAY COUNTY 1 LF	56	COM ORCHARD 1 LF	111	JC HIGH STREET 6 SP	166	PS ALDENE SOLAR 1 SP	221	PS NEW ROAD 1 SP
2	ACE CATES ROAD 2 SP	57	COM SOLBERG 1 BT	112	JC HOFFMAN STATION ROAD 2 SP	167	PS ATHENIA SOLAR 1 SP	222	PS NEWARK SOLAR 1 SP
3	ACE CEDAR BRANCH 1 SP	58	COM STERLING RAIL 1 BT	113	JC HOLLAND 4 SP	168	PS BAYONNE 1 SP	223	PS NEWARK SOLAR 3 SP
4	ACE EGG HARBOR-KELLOGG 1 FC	59	DEOK BECKJORD 1 BT	114	JC HOLMDEL 9 SP	169	PS BAYONNE SOLAR 2 SP	224	PS NIXON LANE 2 SP
5	ACE GALLOWAY LANDFILL 2 SP	60	DEOK BECKJORD 2 BT	115	JC HOWELL 1 SP	170	PS BELLEVILLE SOLAR 1 SP	225	PS NORTH AMERICAN 4 SP
6	ACE GEMS LANDFILL 1 SP	61	DEOK BROWN COUNTY 1 LF	116	JC HOWELL 4 BT	171	PS BENNETTS SOLAR 1 SP	226	PS NORTH AVE SOLAR 1 SP
7	ACE KETTLE RUN 1 SP	62	DEOK CLINTON 1 BT	117	JC JACOBSTOWN 1 SP	172	PS BLACK ROCK 1 SP	227	PS OWENS CORNING 1 SP
8	ACE MAYS LANDING 1 SP	63	DEOK NICKEL - CIN ZOO 1 SP	118	JC JUNCTION ROAD 6 SP	173	PS BRIDGEWATER SOLAR 2 SP	228	PS PARKLANDS 1 SP
9	ACE MIDTOWN THERMAL 2 CT	64	DEOK WILLEY 1 BT	119	JC LAKEHURST 3 SP	174	PS BUSTLETON 2 SP	229	PS PATERSON PLANK ROAD 1 SP
10	ACE OAK FAIRTON 1 SP	65	DPL BLOOM ENERGY 1 FC	120	JC LEBANON 1 SP	175	PS CALDWELL PUMP 2 BT	230	PS PENNINGTON 3 BT
11	ACE PEAR STREET 1 SP	66	DPL BUCKTOWN 1 SP	121	JC LEGLER LANDFILL 7 SP	176	PS CAMPUS DRIVE 2 SP	231	PS PENNINGTON 4 SP
12	ACE PILESGROVE 1 SP	67	DPL CHURCH HILL 1 SP	122	JC MANALAPAN 1 SP	177	PS CEDAR GROVE SOLAR 1 SP	232	PS PENNSAUKEN 1 LF
13	ACE PILESGROVE 2 SP	68	DPL COSTEN 1 SP	123	JC MILLHURST 3 SP	178	PS CEDAR LANE FLORENCE 6 SP	233	PS PENNSAUKEN 3 SP
14	ACE PITTSGROVE 1 SP	69	DPL COSTEN 2 SP	124	JC MOUNT OLIVE 3 SP	179	PS COOK ROAD SOLAR 2 SP	234	PS PRINCETON HOSPITAL 1 CT
15	ACE SEASHORE 1 SP	70	DPL HEBRON 1 SP	125	JC MUDDY FORGE 3 SP	180	PS COOPER HOSPITAL 1 BT	235	PS RARITAN CENTER 3 SP
16	ACE TANSBORO ROAD 1 FC	71	DPL KUMQUAT 1 SP	126	JC NORTH HANOVER 4 SP	181	PS COOPER HOSPITAL 15 SP	236	PS REEVES EAST 3 SP
17	AEP BALLS GAP 1 BT	72	DPL PONDTOWN 1 SP	127	JC NORTH PARK 1 SP	182	PS CRANBURY 2 SP	237	PS REEVES SOUTH 1 SP
18	AEP CHARLESTON 1 LF	73	DPL WORCESTER NORTH 1 SP	128	JC NORTH PARK 2 SP	183	PS CROSSWIC 1 SP	238	PS REEVES WEST 4 SP
19	AEP CLOYDS MT 1 LF	74	DPL WORCESTER SOUTH 2 SP	129	JC NORTH RUN 11 SP	184	PS CROSSWIC 2 SP	239	PS RIDER UNIVERSITY 3 SP
20	AEP DEERCREEK 1 SP	75	DPL WYE MILLS 1 SP	130	JC OLD BRIDGE 1 SP	185	PS DEVILSBROOK 1 SP	240	PS RIVER ROAD 2 SP
21	AEP EAST WATERVLIET 1 SP	76	DUQ BE-PINE 1 SP	131	JC PAUCH 3 SP	186	PS DOREMUS SOLAR 1 SP	241	PS ROSELAND SOLAR 1 SP
22	AEP OLIVE 1 SP	77	DUQ BE-PINE 2 SP	132	JC PEMBERTON 1 SP	187	PS E RUTHERFORD SOLAR 1 SP	242	PS RUTGERS GENERATION 1 F
23	AEP ORCHARD HILLS 1 LF	78	DUQ PIT MICROGRID 1 CT	133	JC PEMBERTON 2 SP	188	PS EASTAMPTON 1 SP	243	PS SADDLE BROOK SOLAR 1 SP
24	AEP RALEIGH COUNTY 1 LF	79	FE DOVETAIL 1 CT	134	JC QUAKERTOWN 9 SP	189	PS EDISON 1 SP	244	PS SPRINGFIELD SOLAR 1 SP
25	AEP TRENT 1 BT	80	FE ERIE COUNTY 1 LF	135	JC RICHLINE 3 SP	190	PS ESSEX 105 CT	245	PS SUNNYMEADE SOLAR 1 SP
26	AEP TWINBRANCH 1 SP	81	FE GENEVA 1 LF	136	JC RINGOES 1 SP	191	PS FAIRLAWN SOLAR 1 SP	246	PS TAYLORS LANE 1 SP
27	AEP ZANESVILLE 2 LF	82	FE LORAIN 1 LF	137	JC ROY ROAD 5 BT	192	PS FOODBANK 1 SP	247	PS THOROFARE SOLAR 2 SP
28	AP BAKER POINT 1 SP	83	FE MAHONING 1 LF	138	JC SUSSEX 1 LF	193	PS FORTY NINTH SOLAR 1 SP	248	PS TURNPIKE 1 SP
29	AP DOUBLE TOLLGATE SP	84	FE WARREN-EVERGREEN 1 CT	139	JC TINTON FALLS 3 SP	194	PS GLOUCESTER SOLAR 1 SP	249	PS W CALDWELL SOLAR 1 SP
30	AP ELK HILL 1 SP	85	JC AUGUSTA 1 SP	140	JC UPPER FREEHOLD 1 SP	195	PS HACKENSACK 1 SP	250	PS W CALDWELL SOLAR 2 SP
31	AP GANS 5 SP	86	JC BEAVER RUN 3 SP	141	JC WANTAGE 2 SP	196	PS HIGHLAND PARK 3 BT	251	PS WALDWICK SOLAR 1 SP
32	AP HAGERSTOWN 1 SP	87	JC BERKSHIRE 2 SP	142	JC WARREN 1 SP	197	PS HIGHLAND PARK 4 SP	252	PS WEST ORANGE SOLAR 1 SP
33	AP HP HOOD 1 CT	88	JC BERNARDS TOWNSHIP 1 SP	143	JC WASHBURN AVE 4 SP	198	PS HILLSDALE SOLAR 1 SP	253	PS WEST PEMBERTON 1 SP
34	AP JADE MEADOW 1 SP	89	JC BRICKYARD 4 SP	144	ME GLENDON 1 LF	199	PS HINCHMANS SOLAR 1 SP	254	PS WEST WINDSOR 1 CT
35	AP LETZBURG - ELK HILL 2 SP	90	JC BRIGHT ROAD 2 BT	145	ME READING HOSPITAL 1 CT	200	PS HOBOKEN SOLAR 2 SP	255	VP BUCKINGHAM 1 SP
36	AP MAHONING CREEK 1 H	91	JC COPPER HILL 4 SP	146	PE MORRIS ROAD 1 D	201	PS HOPEWELL 1 SP	256	VP COLICE HALL 1 SP
37	AP MT ST MARYS PV PARK 2 SP	92	JC CYPHERS ROAD 5 SP	147	PEP CAPITAL POWER PLANT 1 CT	202	PS HOPEWELL 2 BT	257	VP GARDNER FARMS 1 SP
38	AP PECHIN 2 SP	93	JC DIXSOLAR 51 SP	148	PEP ROLLINS AVENUE 3 SP	203	PS JACKSON SOLAR 1 SP	258	VP GARDYS MILL ROAD 5 SP
39	AP PINESBURG 1 SP	94	JC DIXSOLAR 52 SP	149	PEP SPECTRUM 1 SP	204	PS KINSLEY BEAVER 2 SP	259	VP HOLLYFIELD 1 SP
40	AP SPRING LANE 1 SP	95	JC DOMIN LANE 1 SP	150	PL DART CONTAINER 1-2 LF	205	PS KINSLEY DEPTFORD 1 SP	260	VP MURPHY 1 SP
41	AP STATE COLLEGE 1 BT	96	JC DURBAN AVENUE 1 SP	151	PL HOLTWOOD 11	206	PS KUSER SOLAR 1 SP	261	VP NORTHEAST 2 LF
42	AP UNION BRIDGE 1 SP	97	JC E FLEMINGTON 5 SP	152	PL HOLTWOOD 13	207	PS LANDFILL 5 SP	262	VP OCCOQUAN 1 LF
43	BC ALPHA RIDGE 1 LF	98	JC EAST AMWELL 7 SP	153	PL KEYSTONE 1 SP	208	PS LAWNSIDE 14 BT	263	VP OCCOQUAN 2 LF
44	BC BRIGHTON DAM 1 H	99	JC EGYPT 3 SP	154	PL PA SOLAR 1 SP	209	PS LEONIA SOLAR 1 SP	264	VP OCEANA 1 SP
45	BC CHESAPEAKE BEACH 1 BT	100	JC FISCHER 8 SP	155	PL TURKEY HILL 1 WF	210	PS LUMBERTON STACY HAINES 5 SP	265	VP PULLER 1 SP
46	BC FAIRHAVEN 2 BT	101	JC FOUL RIFT ROAD 1 SP	156	PN ALPACA GLORY BARN 1 D	211	PS MANTUA CREEK 7 BT	266	VP QUILLWORT 4 SP
47	BC FAIRVIEW - OTTERPT 1SP	102	JC FRANKFORD 4 SP	157	PN CLARION BOARDS 2 CT	212	PS MARION SOLAR 1 SP	267	VP REMINGTON 1 SP
48	BC FAIRVIEW - OTTERPT 2SP	103	JC FRANKLIN 7 SP	158	PN GARRETT 1 BT	213	PS MATRIX PA SOLAR 2 SP	268	VP ROCHAMBEAU 1 SP
49	BC KINGSVILLE 1 SP	104	JC FREEMALL 1 FC	159	PN LAUREL HIGHLANDS 2 LF	214	PS MAYWOOD SOLAR 1 SP	269	VP SCOTT - POWHATAN 3 HB
50	BC MILLERSVILLE 1 LF	105	JC FRENCHES 2 SP	160	PN LISTONBURG 1 SP	215	PS METRO HQ 2 SP	270	VP TWITTYS CREEK 1 SP
51	COM COUNTRYSIDE 1 LF	106	JC FRENCHTOWN 1 SP	161	PN MEYERSDALE 2 BT	216	PS MIDDLESEX 1 SP	271	VP VIRGINIA OFFSHORE 1 WF
52	COM DIXON LEE 5 LF	107	JC FRENCHTOWN 2 SP	162	PN MILAN ENERGY 1 D	217	PS MILL CREEK 1 SP	272	VP WAN - GLOUCESTER 1 SP
53	COM GRAND RIDGE 6 BT	108	JC FRENCHTOWN 3 SP	163	PN NORTH MESHOPPEN 1 CT	218	PS MOORESTOWN 1 SP	273	VP WHITAKERS 1 SP
54	COM MAGID GLOVE 1 BT	109	JC HANOVER 2 SP	164	PN OXBOW CREEK ENERGY CENTER 1 D	219	PS MT LAUREL 1 SP	274	VP WHITE MARSH - SUFFOLK 1 SP
55	COM MORRIS 1 LF	110	JC HARMONY 1 SP	165	PN WHITETAIL 1 SP	220	PS NEW MILFORD SOLAR 1 SP	275	VP WOODBINE ROAD 1 SP

Figure 12-3 is a map of units, 20 MW or greater in size, that came online between January 1, 2011 and March 31, 2025. A mapping to these unit names is in Table 12-5.

Figure 12-3 Map of unit additions (20 MW or greater): January 1, 2011 through March 31, 2025

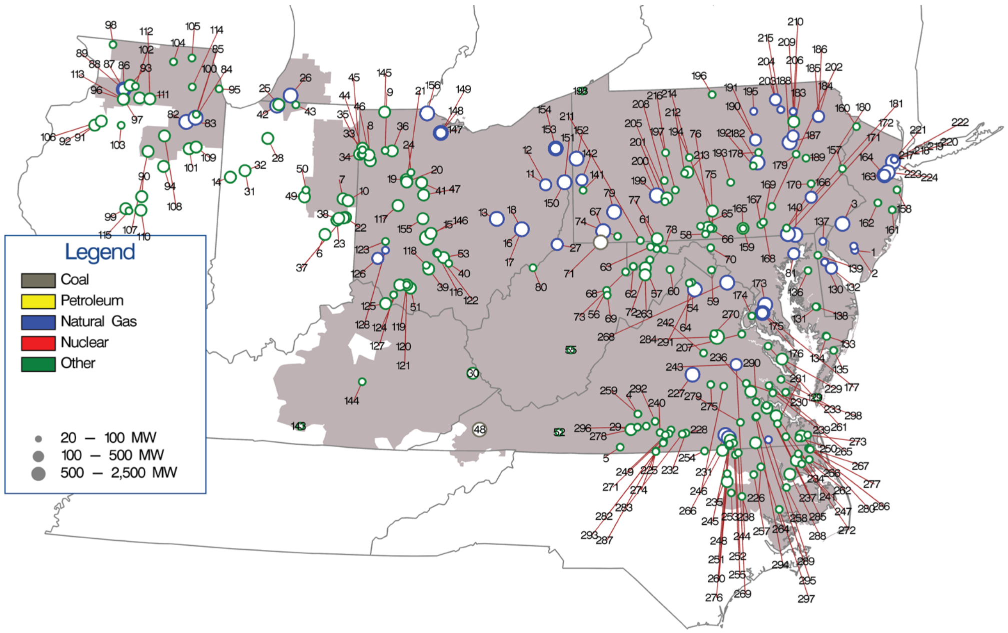


Table 12-5 Unit identification for map of unit additions (20 MW or greater): January 1, 2011 through March 31, 2025

ID	Unit	ID	Unit	ID	Unit	ID	Unit	ID	Unit	ID	Unit
1	ACE CLAYVILLE 1 CT	56	AP BEECH RIDGE 3 BT	111	COM SHADY OAKS 1 WF	166	ME BIRDSBORO 1 CC	221	PS KEARNY 141 CT	276	VP PUMPKINSEED 1 SP
2	ACE VINELAND 11 CT	57	AP BLACK ROCK 1 WF	112	COM SHADY OAKS 2 WF	167	ME COTTONTAIL 1 SP	222	PS KEARNY 142 CT	277	VP RANCHLAND 2 SP
3	ACE WEST DEPTFORD CROWN POINT 1 CC	58	AP BLAIRS VALLEY 12 SP	113	COM WALNUT RIDGE 1 WF	168	ME COTTONTAIL 2 SP	223	PS NEWARK ENERGY CENTER 10 CC	278	VP RENAN 1 SP
4	AEP ALTAVISTA 1 SP	59	AP BLAKE 1 SP	114	COM WEST CHICAGO 3 BT	169	ME COTTONTAIL 8 SP	224	PS SEWAREN 7 CC	279	VP SAPONY 1 SP
5	AEP AXTON 1 SP	60	AP CAPON BRIDGE 1 SP	115	COM WHITNEY HILL 2 WF	170	ME LYONS 1 SP	225	VP ALTON POST OFFICE 1 SP	280	VP SHILLELAGH 1 SP
6	AEP BELLFLOWER 1 SP	61	AP DANS MOUNTAIN 1 WF	116	DAY BUCKEYE PLAINS 2 SP	171	PE DELTA 1-4 CC	226	VP AULANDER HOLLOMAN 1 SP	281	VP SOLIDAGO 1 SP
7	AEP BITTER RIDGE 1 WF	62	AP FAIR WIND 2 WF	117	DAY CLEARVIEW 1 SP	172	PE DELTA 5-7 CC	227	VP BEAR GARDEN	282	VP SOUTH BOSTON 1 F
8	AEP BLUE CREEK 3 WF	63	AP FOURMILE RIDGE 1 WF	118	DAY FAYETTE 1 SP	173	PEP KEYS ENERGY CENTER 1 CC	228	VP BLUESTONE FARM 1 SP	283	VP SPANISH GROVE 1 SP
9	AEP BLUE HARVEST 1 SP	64	AP FOXGLOVE 1 SP	119	DAY HIGHLAND COUNTY 1 SP	174	PEP MILLS GROVE 1 SP	229	VP BOOKERS MILL 1 SP	284	VP SPOTSYLVANIA 1 SP
10	AEP BLUFF POINT 2 WF	65	AP GREAT COVE 1 SP	120	DAY HIGHLAND COUNTY 2 SP	175	PEP ST CHARLES - KELSON RIDGE 1 CC	230	VP BRIEL FARM 1 SP	285	VP SPRING GROVE 1 SP
11	AEP CARROLL COUNTY 1 CC	66	AP GREAT COVE 2 SP	121	DAY HIGHLAND COUNTY 3-4 SP	176	PEP ST CHARLES-KELSON RIDGE 1 CC	231	VP BRUNSWICK 1CC	286	VP SUMMIT FARMS 1 SP
12	AEP CARROLL COUNTY 2 CC	67	AP GREENE COUNTY 1 CC	122	DAY PICKAWAY COUNTY 1 SP	177	PEP ST CHARLES-KELSON RIDGE 2 CC	232	VP BUTCHER CREEK 1 SP	287	VP SUNNYBROOK FARM 1 SP
13	AEP DRESDEN 1 CC	68	AP LAUREL MOUNTAIN 1 BT	123	DAY TAIT 8 BT	178	PL EAST CHILLI 1 SP	233	VP CARVERS CREEK 1 SP	288	VP TIMBERMILL 1 WF
14	AEP FOWLER RIDGE 4 WF	69	AP LAUREL MOUNTAIN 1 WF	124	DEOK HILLCREST 1 SP	179	PL HAZEL 1 FW	234	VP CAVALIER 1 SP	289	VP UNION CAMP 9-10 F
15	AEP FOX SQUIRREL 1 SP	70	AP MARLOWE 1 SP	125	DEOK MELDAHL DAM 1 H	180	PL HOLTWOOD 18	235	VP CHESTNUT 1 SP	290	VP WARDS CREEK 1 SP
16	AEP GUERNSEY 11 CC	71	AP NORTH LONGVIEW 1 F	126	DEOK MIDDLETOWN ENERGY 1 CC	181	PL HOLTWOOD 19	236	VP CHICKAHOMINY 1 SP	291	VP WARREN COUNTY FRONT ROYAL CC
17	AEP GUERNSEY 21 CC	72	AP PINNACLE 1 WF	127	DEOK NESTLEWOOD 1 SP	182	PL HUMMEL STATION 1 CC	237	VP COLONIAL TRAIL WEST 1 SP	292	VP WATER STRIDER 1 SP
18	AEP GUERNSEY 31 CC	73	AP ROTH ROCK 1 WF	128	DEOK YANKEE 1 F	183	PL HUNLOCK CC	238	VP CONETOE 2 SP	293	VP WATLINGTON 1 SP
19	AEP HARDIN 12 SP	74	AP SOUTH CHESTNUT 1 WF	129	DPL CHERRYDALE 1 SP	184	PL LACKAWANNA COUNTY 1 CC	239	VP CORRECTIONAL 1 SP	294	VP WAVERLY 1 SP
20	AEP HARDIN 23 SP	75	AP ST THOMAS 1 SP	130	DPL DEMEC - CLAYTON 2 CT	185	PL LACKAWANNA COUNTY 2 CC	240	VP CRYSTAL HILL 1 SP	295	VP WAVERLY 2 SP
21	AEP HARDIN 34 SP	76	AP ST THOMAS 2 SP	131	DPL DORCHESTER COUNTY 1 SP	186	PL LACKAWANNA COUNTY 3 CC	241	VP DESERT 1 WF	296	VP WHITEHORN 1 SP
22	AEP HEADWATERS 1 WF	77	AP TWIN RIDGES 1 WF	132	DPL GARRISON EC 1 CC	187	PL MOXIE FREEDOM 11 CC	242	VP DESPER 1 SP	297	VP WILKINSON ENERGY CENTER 1 SP
23	AEP HEADWATERS 2 WF	78	AP WARRIOR RUN 2 BT	133	DPL GREAT BAY KINGS CREEK 1 SP	188	PL MOXIE FREEDOM 21 CC	243	VP DOSWELL 2 CT	298	VP WINTERBERRY 1 SP
24	AEP HOG CREEK 1 WF	79	AP WESTMORELAND 1 CC	134	DPL GREAT BAY KINGS CREEK 2 SP	189	PL PA SOLAR 2 SP	244	VP DOSWELL 3 CT		
25	AEP HONEYSUCKLE 1 SP	80	AP WILLOW ISLAND 1 H	135	DPL OAK HALL 1 SP	190	PL PATRIOT 1 F	245	VP DRY BREAD 1 SP		
26	AEP INDECK NILES ENERGY CENTER 1 CC	81	BC PERRYMAN 6 CT	136	DPL PONDTOWN 2 SP	191	PL PATRIOT 2 F	246	VP DRY BRIDGE EC 1 BT		
27	AEP LONG RIDGE ENERGY 1 CC	82	COM 924 THREE RIVERS EC 1 CC	137	DPL RED LION 1 FC	192	PL PENN 3 SP	247	VP ELIZABETH CITY 1 SP		
28	AEP MAMMOTH NORTH 1 SP	83	COM 924 THREE RIVERS EC 2 CC	138	DPL RICHFIELD 3 SP	193	PL WALKER 1 SP	248	VP FOUNTAIN CREEK 1 SP		
29	AEP MAPLEWOOD 1 SP	84	COM 929 JACKSON 1 CC	139	DPL TOWNSEND 1 SP	194	PN ASPEN ROAD 1 SP	249	VP FOXHOUND 1 SP		
30	AEP MARTIN COUNTY 1 SP	85	COM 929 JACKSON 2 CC	140	DPL WILDCAT POINT 1 CC	195	PN BEAVER DAM 1 D	250	VP GRASSFIELD 1 SP		
31	AEP MEADOW LAKE 5 WF	86	COM 942 NELSON 1 CC	141	DUQ GAUCHO 2 SP	196	PN BIG LEVEL 1 WF	251	VP GREENSVILLE 1 CC		
32	AEP MEADOW LAKE 6 WF	87	COM 942 NELSON 2 CC	142	DUQ MONACA-PENNCHEM 1 CC	197	PN CHESTNUT FLATS 1 WF	252	VP GUTENBERG - OCONECHE 1 SP		
33	AEP PAULDING 3 WF	88	COM 942 NELSON 3 CT	143	EKPC GLOVER CREEK 1 SP	198	PN ERIE 1 SP	253	VP HARTS MILL 1 SP		
34	AEP PAULDING 41 WF	89	COM 942 NELSON 4 CT	144	EKPC TURKEY CREEK 1 SP	199	PN FAIRVIEW 1 CC	254	VP HAWTREE CREEK 1 SP		
35	AEP PAULDING 42 WF	90	COM ALTA FARMS II 1 WF	145	FE ARCHE ENERGY 1 SP	200	PN FAIRVIEW 2 CC	255	VP IVORY LANE 1 SP		
36	AEP POWELL CREEK - LAMMER 1 SP	91	COM BISHOP HILL 1 WF	146	FE BIG PLAIN 2 SP	201	PN HIGHLAND NORTH 2 WF	256	VP IVY NECK 2 SP		
37	AEP RIVERSTART 1 SP	92	COM BISHOP HILL 2 WF	147	FE FREMONT 1 SCCT	202	PN LAUREL HILLS 1 WF	257	VP KELFORD 1 SP		
38	AEP RIVERSTART 3 SP	93	COM BLOOMING GROVE 1 WF1	148	FE FREMONT 2 SCCT	203	PN LIBERTY ASYLUM 10 F	258	VP MACKEYS ALBERMAE 1 SP		
39	AEP ROSS COUNTY 1 SP	94	COM BRIGHT STALK 1 WF	149	FE FREMONT ENERGY CENTER 3 CC	204	PN LIBERTY ASYLUM 20 F	259	VP MECHANICSVILLE 2 SP		
40	AEP SALT CITY 1 SP	95	COM GRAND RIDGE 7 BT	150	FE HIBBETS MILL SOUTHFIELD 1 CC	205	PN MAPLE HILL-FIDDLERS 1 SP	260	VP MOCCASIN CREEK - FERN 1 SP		
41	AEP SCIOTO RIDGE 1 WF	96	COM GREEN RIVER 1 WF	151	FE HIBBETS MILL SOUTHFIELD 2 CC	206	PN MEHOOPANY 1 WF	261	VP MONTROSS 1 SP		
42	AEP ST JOSEPH ENERGY CENTER 1 CC	97	COM GREEN RIVER 2 WF	152	FE HICKORY RUN 1 CC	207	PN MEHOOPANY 2 WF	262	VP MORGAN CORNER 1 SP		
43	AEP ST JOSEPH SOLAR PARK 1 SP	98	COM HIGHPOINT 11 SP	153	FE LORDSTOWN ENERGY CENTER 1 CC	208	PN PATTON 1 WF	263	VP NEW CREEK 1 WF		
44	AEP TIMBER ROAD 1 SP	99	COM HILLTOPPER 1 WF	154	FE LORDSTOWN ENERGY CENTER 2 CC	209	PN PGCOGEN 1 CT	264	VP NEWSOMS 1 SP		
45	AEP TIMBER2 1 WF	100	COM JOLIET 1 BT	155	FE MADISON FIELDS 1 SP	210	PN PGCOGEN 2 CT	265	VP NORGE 2 SP		
46	AEP TRISHE 1 WF	101	COM KELLY CREEK 1 WF	156	FE OREGON ENERGY CENTER 1 CC	211	PN RINGER HILL 1 WF	266	VP OAK 1 SP		
47	AEP UNION 1 SP	102	COM LEE DEKALB 3 BT	157	JC EDGE ROAD 5 BT	212	PN SANDY RIDGE 1 WF	267	VP OAK TRAIL 1 SP		
48	AEP VIRGINIA CITY 1 F	103	COM LONE TREE 3 WF	158	JC HAMILTON ROAD 5 SP	213	PN SANDY RIDGE 2 WF	268	VP PANDA STONEWALL 1 CC		
49	AEP WILDCAT 1A WF	104	COM MARENGO 1 BT	159	JC JUSTIN COURT 10 BT	214	PN SCHOOL HOUSE 1 SP	269	VP PECAN 1 SP		
50	AEP WILDCAT 1B WF	105	COM MCHENRY 1 BT	160	JC MONTAGUE STORAGE 3 BT	215	PN SUGAR RUN 2 CT	270	VP PINE GLADE 1 SP		
51	AEP WILLOWBROOK 1 SP	106	COM MIDLAND 1 WF	161	JC OAK RIDGE 3 SP	216	PN VIADUCT 1 SP	271	VP PINEY CREEK 1 SP		
52	AEP WYTHE COUNTY 1 SP	107	COM MINONK 1 WF	162	JC PLUMSTED ENERGY 6 BT	217	PS KEARNY 131 CT	272	VP PLEASANT HILL - SUFFOLK 2 SP		
53	AEP YELLOWBUD 1 SP	108	COM OTTER CREEK 1 WF	163	JC WOODBRIDGE 1 CC	218	PS KEARNY 132 CT	273	VP POCATY 1 SP		
54	AP BARTONSVILLE 1 SP	109	COM PILOT HILL 1 WF	164	JC WOODBRIDGE 2 CC	219	PS KEARNY 133 CT	274	VP POWELLS CREEK 1 SP		
55	AP BEECH RIDGE 2 WF	110	COM RADFORDS RUN 1 WF	165	ME ADAMS 1 SP	220	PS KEARNY 134 CT	275	VP POWHATAN 2 SP		

Generation Retirements[39] [40]

Generating units generally plan to retire when they are not economic and do not expect to be economic. Generating units may also plan to retire if environmental restrictions make it too costly to comply or impossible to comply. 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.[41] 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. The U. S. Department of Energy does have the authority to temporarily order generating plants to continue operating under section 202(c) of the Federal Power Act in the event of emergency or reliability issues.[42]

Rules that preserve ownership of the Capacity Interconnection Rights (CIRs) associated with retired units, and with the conversion from Capacity Performance (CP) to energy only status, impose significant costs on new entrants. Currently, CIRs persist for one year if unused, and that period can be further extended, at no cost, if the CIRs are assigned to a new project in the interconnection queue at the same point of interconnection.[43] 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 that terminate CIRs on the date of retirement, would make new entry appropriately more attractive. There is no good economic and policy rationale for extending ownership rights to CIRs for inactive units. Incumbent providers receive a significant advantage simply by imposing on new entrants the entire cost of system upgrades needed to accommodate new entrants. 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.[44] The MMU recognized the progress made in this rule change, but it did not fully address the issues. 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 or to exercise market power by requiring high payments for CIRs. The MMU recommends that CIRs should end on the date of retirement in order to help ensure competitive markets and competitive access to the grid.

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. The MMU recommends that all capacity resources have a must offer requirement.[45]

Generation Retirements 2011 through 2028

Table 12-6 shows that as of March 31, 2025, there are 62,810.2 MW of generation that have been, or are planned to be, retired from 2011 through 2028, of which 45,302.8 MW (72.1 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.

39 See PJM. Planning. "Generator Deactivations," (Accessed on March 31, 2025) <https://www.pjm.com/planning/service-requests/gen-deactivations>.
40 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.
41 See OATT Part V and Attachment M–Appendix § IV.
42 See 16 U.S.C. § 824a(c).
43 See OATT § 230.3.3.
44 See PJM Interconnection, L.L.C., Docket No. ER12-1177 (Feb. 29, 2012).
45 For more information, see *2025 Quarterly State of the Market Report for PJM: January through March*, Section 5: Capacity Market.

Table 12-6 Summary of unit retirements by unit type (MW): 2011 through 2028

	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	36.6	0.0	0.0	0.0	5,385.0	0.0	0.0	0.0	0.0	0.0	6,162.4
Retirements 2023	0.0	114.0	52.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	36.0	19.2	0.0	0.0	0.0	4,380.0	1,326.0	800.0	0.0	0.0	0.0	6,727.8
Retirements 2024	28.5	0.0	149.2	108.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	11.7	0.0	0.0	0.0	180.0	0.0	0.0	50.0	0.0	0.0	527.4
Retirements 2025	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	410.0	0.0	0.0	0.0	0.0	0.0	410.0
Planned Retirements (April 1, 2025 and later)	6.0	0.0	2,120.0	29.3	0.0	0.0	0.0	0.0	0.0	0.0	2.0	14.1	2.5	0.0	0.0	3,893.0	886.0	702.0	0.0	0.0	0.0	7,654.9
Total	120.5	897.5	4,705.1	2,322.5	22.0	0.0	0.5	0.0	1,419.5	0.0	82.1	162.0	2.5	0.0	0.0	45,302.8	4,300.8	3,160.0	302.0	10.4	0.0	62,810.2

Table 12-7 shows the capacity, average size, and average age of units retiring in PJM, from 2011 through 2028, while Table 12-8 shows these retirements by state. Of the 62,810.2 MW of units that has been, or are planned to be, retired from 2011 through 2028, 45,302.8 MW (72.1 percent) are coal fired steam units. These coal fired steam units have an average age of 52.0 years and an average size of 236.0 MW. Over half of the retiring coal fired steam units, 52.5 percent, are located in Ohio or Pennsylvania.

Table 12-7 Retirements by unit type: 2011 through 2028

Unit Type	Number of Units	Avg. Size (MW)	Avg. Age at Retirement (Years)	Total MW	Percent
Battery	11	11.0	7.7	120.5	0.2%
Combined Cycle	7	128.2	29.6	897.5	1.4%
Combustion Turbine	159	31.1	35.2	7,049.6	11.2%
Natural Gas	84	56.0	39.4	4,705.1	7.5%
Oil	69	33.7	47.0	2,322.5	3.7%
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	2.3%
RICE	45	5.3	26.4	244.1	0.4%
Natural Gas	0	0.0	0.0	0.0	0.0%
Oil	17	4.8	39.3	82.1	0.1%
Other	28	5.8	13.4	162.0	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	236	196.5	46.0	53,065.6	84.5%
Coal	192	236.0	52.0	45,302.8	72.1%
Natural Gas	26	165.4	57.8	4,300.8	6.8%
Oil	9	351.1	49.0	3,160.0	5.0%
Other	9	33.6	25.3	302.0	0.5%
Wind	1	10.4	15.6	10.4	0.0%
Wind + Storage	0	0	0	0	0.0%
Total	463	135.7	44.1	62,810.2	100.0%

Table 12-8 Retirements (MW) by unit type and state: 2011 through 2028

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	16.4	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	816.4
IL	45.5	0.0	2,095.9	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	6,321.2
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	3,602.0	0.0	0.0	0.0	0.0	0.0	3,602.0
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	20.0	0.0	347.5	274.9	1.6	0.0	0.0	0.0	0.0	0.0	2.0	3.2	0.0	0.0	0.0	4,521.0	297.0	702.0	0.0	0.0	0.0	6,169.2
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	579.5	2,060.3	1,066.2	6.4	0.0	0.5	0.0	614.5	0.0	8.0	36.6	2.5	0.0	0.0	2,001.9	932.5	148.0	10.0	0.0	0.0	7,466.9
OH	52.0	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	17,044.6
PA	1.0	51.0	121.4	307.3	14.0	0.0	0.0	0.0	805.0	0.0	15.9	20.5	0.0	0.0	0.0	7,180.0	1,046.3	176.0	109.0	10.4	0.0	9,857.8
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	20.1	0.0	0.0	0.0	3,897.9	563.0	1,586.0	133.0	0.0	0.0	6,650.6
WV	2.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,691.0	0.0	0.0	0.0	0.0	0.0	2,693.0
Total	120.5	897.5	4,705.1	2,322.5	22.0	0.0	0.5	0.0	1,419.5	0.0	82.1	162.0	2.5	0.0	0.0	45,302.8	4,300.8	3,160.0	302.0	10.4	0.0	62,810.2

Figure 12-4 is a map of unit retirements from 2011 through 2028, with a mapping to unit names in Table 12-9.

Figure 12-4 Map of unit retirements: 2011 through 2028

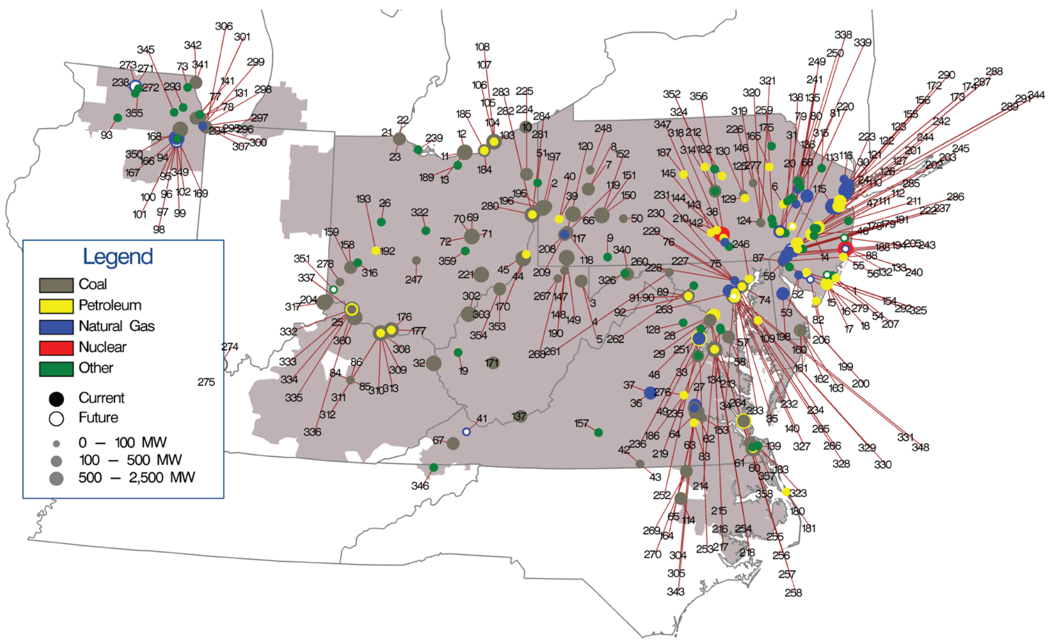


Table 12-9 Unit identification for map of unit retirements: 2011 through 2028

ID	Unit	ID	Unit	ID	Unit	ID	Unit	ID	Unit	ID	Unit
1	AC Landfill Units 1 and 2	61	Chesapeake 7-10	121	Essex 10-11	181	Kitty Hawk GT 2	241	PL MARTINS CREEK 1-4 CT	301	Southeast Chicago GT9
2	AES Beaver Valley	62	Chesterfield 3	122	Essex 12	182	Koppers Co. IPP	242	Parlin NUG	302	Sporn 1-4
3	Albright 1	63	Chesterfield 4	123	Essex 9	183	Lake Kingman	243	Pedricktown Cogen CC	303	Sporn 5
4	Albright 2	64	Chesterfield 5	124	Evergreen Power United Corstack	184	Lake Shore 18	244	Pennsbury Generator Landfill 1	304	Spruance NUG1 (Rich 1-2)
5	Albright 3	65	Chesterfield 6	125	FRACKVILLE WHEELABRATOR 1	185	Lake Shore EMD	245	Pennsbury Generator Landfill 2	305	Spruance NUG2 (Rich 3-4)
6	Allentown CT 1-4	66	Cheswick 1	126	Fairless Hills Landfill A	186	Lanier 1 CT	246	Perryman 2	306	State Line 3
7	Armstrong 1	67	Clinch River 3	127	Fairless Hills Landfill B	187	Lock Haven CT 1	247	Picway 5	307	State Line 4
8	Armstrong 2	68	Columbia Dam Hydro	128	Fauquier County Landfill	188	Logan	248	Piney Creek NUG	308	Stuart 1
9	Arnold (Green Mtn.) Wind Farm	69	Conesville 3	129	Fishbach CT 1	189	Lorain 1 LF	249	Portland 1	309	Stuart 2
10	Ashtabula 5	70	Conesville 4	130	Fishbach CT 2	190	MEA NUG (WVU)	250	Portland 2	310	Stuart 3
11	Avon Lake 10	71	Conesville 5	131	Fisk Street 19	191	MH50 Markus Hook Co-gen	251	Possum Point 3	311	Stuart 4
12	Avon Lake 7	72	Conesville 6	132	Forked River Unit 1	192	Mad River CTs A	252	Possum Point 4	312	Stuart Diesels 1-4
13	Avon Lake 9	73	Countryside Landfill	133	Forked River Unit 2	193	Mad River CTs B	253	Possum Point 5	313	Stuart Diesels 1-4
14	BC Landfill	74	Crane 1	134	GUDE Landfill	194	Manchester 1 LF	254	Potomac River 1	314	Sunbury 1-4
15	BL England 1	75	Crane 2	135	Gilbert 1-4	195	Mansfield 1	255	Potomac River 2	315	Sussex County LF
16	BL England 2	76	Crane GT1	136	Glen Gardner 1-8	196	Mansfield 2	256	Potomac River 3	316	Tait Battery
17	BL England 3	77	Crawford 7	137	Glen Lyn 5-6	197	Mansfield 3	257	Potomac River 4	317	Tanners Creek 1-4
18	BL England Diesel Units 1-4	78	Crawford 8	138	Glendon LF	198	McKee 1	258	Potomac River 5	318	Three Mile Island Unit 1
19	Balls Gap Battery Facility	79	Cromby 1	139	Gosport 1 F	199	McKee 2	259	Pottstown LF (Moser)	319	Titus 1
20	Barbados AES Battery	80	Cromby 2	140	Gould Street Generation Station	200	McKee 3	260	R Paul Smith 3	320	Titus 2
21	Bay Shore 2	81	Cromby D	141	Grand Ridge Energy IV battery component	201	Mercer 1	261	R Paul Smith 4	321	Titus 3
22	Bay Shore 3	82	Cumberland CT 1	142	Harrisburg 4 CT	202	Mercer 2	262	Reichs Ford Road Landfill Generator	322	Trent Battery Storage
23	Bay Shore 4	83	DINWIDDIE 1 CT	143	Harrisburg CT 1	203	Mercer 3	263	Riverside 4	323	VP Virginia Beach
24	Bayonne Cogen Plant (CC)	84	Dale 1-2	144	Harrisburg CT 2	204	Miami Fort 6	264	Riverside 6	324	Viking Energy NUG
25	Beckjord Battery Unit 2	85	Dale 3	145	Harrisburg CT 3	205	Mickleton CT1	265	Riverside 7	325	Vineland West CT
26	Bellefontaine Landfill Generating Station	86	Dale 4	146	Harwood 1-2	206	Middle 1-3	266	Riverside 8	326	WARRIOR RUN 2 BT
27	Bellemeade	87	Deepwater 1	147	Hatfield's Ferry 1	207	Missouri Ave B,C,D	267	Riversville 5	327	Wagner 1
28	Benning 15	88	Deepwater 6	148	Hatfield's Ferry 2	208	Mitchell 2	268	Riversville 6	328	Wagner 2
29	Benning 16	89	Dickerson CT1	149	Hatfield's Ferry 3	209	Mitchell 3	269	Roanoke Valley 1	329	Wagner 3
30	Bergen 3	90	Dickerson Unit 1	150	Homer City 1	210	Modern Power Landfill NUG	270	Roanoke Valley 2	330	Wagner 4
31	Bethlehem Renewable Energy Generator (Landfill)	91	Dickerson Unit 2	151	Homer City 2	211	Monmouth NUG landfill	271	Rockford CT11	331	Wagner CT 1
32	Big Sandy 2	92	Dickerson Unit 3	152	Homer City 3	212	Montour ATG	272	Rockford CT12	332	Walter C Beckjord 1
33	Birchwood Plant	93	Dixon Lee Landfill Generator	153	Hopewell James River Cogeneration	213	Morgantown CT 5	273	Rockford CT21	333	Walter C Beckjord 2
34	Brandon Shores 1	94	ELWOOD CT 1	154	Howard Down 10	214	Morgantown CT 6	274	Rockport Unit 1	334	Walter C Beckjord 3
35	Brandon Shores 2	95	ELWOOD CT 2	155	Hudson 1	215	Morgantown CT1	275	Rockport Unit 2	335	Walter C Beckjord 4
36	Bremo 3	96	ELWOOD CT 3	156	Hudson 2	216	Morgantown CT2	276	Rockville CT	336	Walter C Beckjord 5-6
37	Bremo 4	97	ELWOOD CT 4	157	Hurt NUG	217	Morgantown Unit 1	277	Rolling Hills Landfill Generator	337	Walter C Beckjord GT 1-4
38	Brunner Island Diesels	98	ELWOOD CT 5	158	Hutchings 1-3, 5-6	218	Morgantown Unit 2	278	SMART Paper	338	Warren County Landfill
39	Brunot Island 1B	99	ELWOOD CT 6	159	Hutchings 4	219	Morris Landfill Generator	279	Salem County LF	339	Warren County NUG
40	Brunot Island 1C	100	ELWOOD CT 7	160	Indian River CT10	220	Morris Road 1 D	280	Sammis 1-4	340	Warrior Run
41	Buchanan Units 1 and 2	101	ELWOOD CT 8	161	Indian River 1	221	Muskingum River 1-5	281	Sammis Diesel Units	341	Waukegan 7
42	Buggs Island 1 (Mecklenberg)	102	ELWOOD CT 9	162	Indian River 3	222	National Park 1	282	Sammis Unit 5	342	Waukegan 8
43	Buggs Island 2 (Mecklenberg)	103	Eastlake 1	163	Indian River 4	223	New Bay Cogen CC	283	Sammis Unit 6	343	Weakley CT
44	Burger 3	104	Eastlake 2	164	Ingenco Petersburg	224	Niles 1	284	Sammis Unit 7	344	Werner 1-4
45	Burger EMD	105	Eastlake 3	165	Jenkins CT 1-2	225	Niles 2	285	Schuylkill 1	345	West Chicago Energy Storage
46	Burlington 8,11	106	Eastlake 4	166	Joliet 6	226	Northeastern Power NEPCO	286	Schuylkill Diesel	346	West Kingsport LF
47	Burlington 9	107	Eastlake 5	167	Joliet 7	227	Notch Cliff GT1	287	Sewaren 1	347	West Shore CT 1-2
48	Buzzard Point East Banks 1,2,4-8	108	Eastlake 6	168	Joliet 8	228	Notch Cliff GT2	288	Sewaren 2	348	Westport 5
49	Buzzard Point West Banks 1-9	109	Easton Diesel Unit 8	169	Joliet Energy Storage	229	Notch Cliff GT3	289	Sewaren 3	349	Will County 3
50	Cambria CoGen	110	Eddystone 1	170	Kammer 1-3	230	Notch Cliff GT4	290	Sewaren 4	350	Will County 4
51	Carbon Limestone LF	111	Eddystone 2	171	Kanawha River 1-2	231	Notch Cliff GT5	291	Sewaren 6	351	Willey Energy Storage
52	Carlls Corner CT1	112	Eddystone Unit 3	172	Kearny 10	232	Notch Cliff GT6	292	Sherman Avenue CT1	352	Williamsport-Lycoming CT 1-2
53	Carlls Corner CT2	113	Eddystone Unit 4	173	Kearny 11	233	Notch Cliff GT7	293	Solberg 1 BT	353	Willow Island 1
54	Cates Road Solar	114	Edgecomb NUG (Rocky 1-2)	174	Kearny 9	234	Notch Cliff GT8	294	Southeast Chicago CT11	354	Willow Island 2
55	Cedar 1	115	Edison 1-3	175	Keystone Recovery (Units 1 - 7)	235	Oaks Landfill	295	Southeast Chicago CT12	355	Winnebago Landfill
56	Cedar 2	116	Elmwood Park Power	176	Killen 2	236	Occoquan 1 LF	296	Southeast Chicago CT5	356	York Generation Facility
57	Chalk Point Unit 1	117	Elrama 1	177	Killen CT	237	Ocean County LF	297	Southeast Chicago CT6	357	Yorktown 1-2
58	Chalk Point Unit 2	118	Elrama 2	178	Kimberly Clark Generator	238	Orchard Hills LF	298	Southeast Chicago CT7	358	Yorktown 3
59	Chambers CCLP	119	Elrama 3	179	Kinsley Landfill	239	Ottawa County Project	299	Southeast Chicago CT8	359	Zanesville Landfill
60	Chesapeake 1-4	120	Elrama 4	180	Kitty Hawk GT 1	240	Oyster Creek	300	Southeast Chicago GT10	360	Zimmer 1

Current Year Generation Retirements

Table 12-10 shows that in the first three months of 2025, 410.0 MW of generation retired. The largest generator that retired in the first three months of 2025 was the 410.0 MW Indian River 4 coal fired steam unit located in the DPL Zone. Of the 410.0 MW of generation that retired, 410.0 MW (100.0 percent) were located in the DPL Zone.

Table 12-10 Unit deactivations: January through March, 2025

Owner	Unit Name	ICAP (MW)	Unit Type	Zone Name	Age (Years)	Retirement Date
NRG Energy Inc	Indian River 4	410.0	Steam-Coal	DPL	44	24-Feb-25
Total		410.0				

Planned Generation Retirements

Table 12-11 shows that, as of March 31, 2025, there are 7,654.9 MW of generation that have requested retirement after March 31, 2025. Of the 7,654.9 MW requesting retirement, 3,893.0 MW (50.9 percent) are coal fired steam units. Of the 7,654.9 MW of planned retirements, 2,700.0 MW (35.3 percent) are located in the AEP Zone. Of the generation requesting retirement in the AEP Zone, 2,620.0 MW (97.0 percent) are coal fired steam units.

Table 12-11 Planned retirement of units: March 31, 2025

Owner	Unit Name	ICAP (MW)	Unit Type	Zone Name	Projected Deactivation Date
The Goldman Sachs Group Inc.	Cates Road Solar	2.5	Solar	ACEC	01-Apr-25
NextEra Energy, Inc.	Manchester 1 LF	5.0	RICE-Other	JCPLC	01-Apr-25
Constellation Energy Generation, LLC	Eddystone Unit 3	380.0	Steam-Natural Gas	PECO	31-May-25
Constellation Energy Generation, LLC	Eddystone Unit 4	380.0	Steam-Natural Gas	PECO	31-May-25
Pennoni Associates Inc	Morris Road 1 D	2.0	RICE-Oil	PECO	31-May-25
Talen Energy Corporation	Wagner 1	126.0	Steam-Natural Gas	BGE	01-Jun-25
Talen Energy Corporation	Wagner CT 1	12.9	CT-Oil	BGE	01-Jun-25
LS Power Equity Partners, L.P.	Buchanan Units 1 and 2	80.0	CT-Natural Gas	AEP	01-Jul-25
NextEra Energy, Inc.	Ocean County LF	9.1	RICE-Other	JCPLC	01-Jul-25
Sumitomo Corporation	Willey Energy Storage	6.0	Battery	DUKE	01-Sep-25
Electric Power Development Co. Ltd.	ELWOOD CT 1	150.0	CT-Natural Gas	COMED	01-Jun-26
Electric Power Development Co. Ltd.	ELWOOD CT 2	150.0	CT-Natural Gas	COMED	01-Jun-26
Electric Power Development Co. Ltd.	ELWOOD CT 3	150.0	CT-Natural Gas	COMED	01-Jun-26
Electric Power Development Co. Ltd.	ELWOOD CT 4	150.0	CT-Natural Gas	COMED	01-Jun-26
Electric Power Development Co. Ltd.	ELWOOD CT 5	150.0	CT-Natural Gas	COMED	01-Jun-26
Electric Power Development Co. Ltd.	ELWOOD CT 6	150.0	CT-Natural Gas	COMED	01-Jun-26
Electric Power Development Co. Ltd.	ELWOOD CT 7	150.0	CT-Natural Gas	COMED	01-Jun-26
Electric Power Development Co. Ltd.	ELWOOD CT 8	150.0	CT-Natural Gas	COMED	01-Jun-26
Electric Power Development Co. Ltd.	ELWOOD CT 9	150.0	CT-Natural Gas	COMED	01-Jun-26
Hull Street Energy LLC	Forked River Unit 2	31.0	CT-Natural Gas	JCPLC	01-Jun-26
NRG Energy Inc	Indian River CT10	16.4	CT-Oil	DPL	01-Jun-26
LS Power Equity Partners, L.P.	Rockford CT11	149.1	CT-Natural Gas	COMED	01-Jun-26
LS Power Equity Partners, L.P.	Rockford CT12	147.8	CT-Natural Gas	COMED	01-Jun-26
LS Power Equity Partners, L.P.	Rockford CT21	153.0	CT-Natural Gas	COMED	01-Jun-26
Bridgepoint Group PLC	Cumberland CT 1	90.8	CT-Natural Gas	ACEC	01-Jun-27
Hull Street Energy LLC	Forked River Unit 1	34.0	CT-Natural Gas	JCPLC	01-Jun-27
Bridgepoint Group PLC	Sherman Avenue CT1	84.3	CT-Natural Gas	ACEC	01-Jun-27
Talen Energy Corporation	Brandon Shores 1	635.0	Steam-Coal	BGE	31-Dec-28
Talen Energy Corporation	Brandon Shores 2	638.0	Steam-Coal	BGE	31-Dec-28
American Electric Power Company, Inc.	Rockport Unit 1	1,320.0	Steam-Coal	AEP	31-Dec-28
American Electric Power Company, Inc.	Rockport Unit 2	1,300.0	Steam-Coal	AEP	31-Dec-28
Talen Energy Corporation	Wagner 3	305.0	Steam-Oil	BGE	31-Dec-28
Talen Energy Corporation	Wagner 4	397.0	Steam-Oil	BGE	31-Dec-28
Total		7,654.9			

In addition to the 7,654.9 MW of announced unit retirements as of March 31, 2025, there are significantly more unit retirements expected as a result of environmental regulations and for economic reasons.[46]

Generation Queue[47]

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.[48] 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 AJ1 opened on April 1, 2023, and closed on July 10, 2023, coincident with the transition to the new queue process. 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.[49] This change allowed 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.[50]

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.[51] 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.[52] 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.[53] 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.[54]

46 For more information, see *2025 Quarterly State of the Market Report for PJM: January through March*, Section 7: Net Revenue.
47 Unless otherwise noted, the queue totals in this report are the winter net MW energy for the interconnection requests ("MW Energy") as shown in the queue.
48 See OATT Parts IV & VI.
49 See PJM Filing, Docket ER21-2203 (June 24, 2021).
50 176 FERC ¶ 61,117 (2021).
51 See PJM Filing, Docket ER21-2203 (June 24, 2021).
52 176 FERC ¶ 61,117 (2021).
53 See "PJM Manual 14C: Generation and Transmission Interconnection Process," Rev. 16 (July 26, 2023).
54 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.

In 2022, after a lengthy stakeholder process (Interconnection Process Reform Task Force (IPRTF)) PJM filed significant changes to improve overall queue management. On November 29, 2022, the Commission issued an order accepting PJM's tariff revisions modifying how PJM manages the new services queue.[55] The new queue process includes modifications to implement a cluster/cycle based processing method to replace the first in/first out processing method.[56] 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 new process also includes defining progress to completion through three phases, with a customer decision at the end of each. The new process 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 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 new process 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 transition to the new queue process began on July 10, 2023.

The transition to the new queue process began on July 10, 2023. The last open queue prior to July 10, 2023, was AJ1. The new process includes a transition which treats projects based on their current queue status. All projects through queue window AD2 will continue as part of the previous queue process. The transition process assigns existing queue projects in queue windows AE1 through AH1 to transition cycle 1 (TC1) and transition cycle 2 (TC2) 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. The start of the transition to the new queue process on July 10, 2023, also started the 60 day readiness review period for active projects in the AE1 through AG1 queues. During this time, project developers provided evidence of site control and provided the necessary readiness deposit.[57] Those projects in the AE1 through AG1 queues that had not yet received an interconnection service agreement or a wholesale market power agreement and also met readiness requirements were reviewed to determine if they were eligible for the fast track process, or if they will be studied as part of transition cycle 1. Of the 734 projects in queues AE1 through AG1 reviewed, 306 projects (41.7 percent) qualified for the expedited process, 312 projects (42.5 percent) were assigned to transition cycle 1 and 116 projects (15.8 percent) were withdrawn from the queue. Transition cycle 1 began in early 2024. On December 20, 2024, coincident with the start of Phase 3 of Transition cycle 1, the application submission deadline for Transition cycle 2 closed. Phase 1 of Transition cycle 2 is expected to begin in the second quarter of 2025. Projects already submitted in queue windows AH2 through AJ1 will be evaluated starting in early 2026 under the new queue process. While new applications will continue to be accepted, the transition process will delay their consideration for an unknown

55 181 FERC ¶ 61,162 (2022).

56 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>.

57 See "PJM Manual 14H: New Service Requests Cycle Process," Rev. 00 (July 26, 2023) for a complete list of all readiness requirements.

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.

The transition process must also account for the fact that PJM significantly underestimated the level of CIRs required for intermittent resources. PJM had required only CIRs equal to the ELCC rating of intermittent resources when in fact those resources required CIRs equal to the maximum output that contributed to the ELCC rating. In general, CIRs were understated by the difference between the ELCC derating factor and the maximum facility output of the intermittent resource. PJM filed revised rules and FERC approved them.[58] PJM has created a process to permit such resources to increase their CIRs to the required level through appropriate investments in interconnection facilities.

On July 28, 2023, the Commission issued Order No. 2023.[59] The rule largely aligns with the PJM approach that has been accepted by FERC.[60] The rule 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.[61]

58 183 FERC ¶61,009.
59 See *Improvements to Generator Interconnection Procedures and Agreements*, Docket No. RM22-14-000, 184 FERC ¶ 61,054.
60 181 FERC ¶ 61,162 (2022).
61 Once implemented, the approved solutions from PJM's Interconnection Process Reform Task Force (IPRTF) should result in improvements in these areas.

Interconnection Process Studies and Agreements[62]

Serial Service Process

Prior to implementation of the new Cycle Process, PJM used a Serial Service Process. 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 performs in the study stage of the interconnection process. System impact and facilities studies are often redone when a project is withdrawn in order to determine the impact on the projects remaining in the queue.

Table 12-12 Interconnection planning process: study stage

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

In 2016, the PJM Earlier Queue Submitted Task Force stakeholder group made changes to the interconnection process to address some of the issues related to delays observed in the various stages of the study phase. The changes became effective with the AC2 Queue that closed on March 31, 2017. The MMU recommends continuing analysis of the 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

62 See "PJM Manual 14A: New Services Request Process," Rev. 30 (July 26, 2023) for a complete explanation of the interconnection process studies and agreements.

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.

New Service Requests Cycle Process[63]

The transition to the new queue process began on July 10, 2023. The new queue process includes modifications to implement a cluster/cycle based processing method to replace the first in/first out processing method.[64] Each cycle consists of the: application phase, phase I, decision point I, phase II, decision point II, phase III, decision point III, and the final agreement negotiation phase.

Application Phase

The application phase includes the submission and review of a new service request. A new service request could be a request to interconnect a new generating facility, a request to increase the capability of an existing generating facility, a request to interconnect a merchant transmission facility, a request to increase the capability of an existing merchant transmission facility, a request to interconnect a generating facility to distribution facilities

63 Material in this section is based on information found in PJM Manual 14H. See "PJM Manual 14H: New Service Requests Cycle Process," Rev. 00 (July 26, 2023).

64 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>.

located in PJM that are to be used for transmission of power in interstate commerce, and to make wholesale sales or a long term firm transmission service request outside of the 18 month available transfer capability (ATC) horizon. The deadline for submitting applications for a new cycle corresponds with the completion of phase II of the previous cycle. For an application to be considered complete, and included in a cycle, PJM must receive a completed and executed application and studies agreement (ASA), required technical information, a wire transfer for the entirety of study deposit, a wire transfer or letter of credit for the entirety of Readiness Deposit No. 1 and, for generation requests, evidence of site control.

Phase I

Phase 1 of a cycle begins after the application phase of a cycle is completed and a group of valid new service requests is established. During phase I of a cycle, PJM performs a phase I system impact study (SIS). The phase I SIS is conducted on an aggregate basis within a cycle, and results are provided in a single cycle format. The phase I SIS results are posted on PJM's website. The phase I SIS evaluates each new service request on a summer peak, winter peak and light load RTEP base case. PJM only performs a load flow analysis during the phase I system impact study. In phase I of the cycle, PJM also conducts an affected system screen and provides each affected system operator with a list of new service requests within the cycle including potential impacts to their system. During phase 1, PJM creates both the short circuit and stability base cases that will be used in the phase II SIS.

Decision Point I

New service requests that are studied in phase I will enter decision point I. After reviewing the results of the phase I SIS, the project developer must decide whether or not to move forward to phase II of the process. Decision point I starts on the first business day following the end of phase I and closes 30 calendar days later. Before the close of decision point I, the project developer can choose to either remain in the cycle by meeting the decision point I requirements or to withdraw its new service request. If a project developer fails to submit all required deposits, evidence, and data before the close of decision point I, the new service request will be terminated and withdrawn.

Phase II

After the decision point I phase of a cycle is completed and a group of valid new service requests is established, phase II of a cycle will begin. During phase II of a cycle, PJM performs the phase II SIS. PJM retools the load flow results from the phase I SIS (summer peak, winter peak and light load) based on decisions made during decision point I. PJM also conducts any required voltage analyses, performs short circuit and stability analyses and coordinates with affected systems to confirm which projects in the cycle will require affected system studies. If the affected system operator indicates that an affected system study is required, PJM notifies the project developer of the need for an affected system study and the requirement to execute an affected system study agreement with the impacted affected system operator. If applicable and available, PJM includes the results of the affected system operator's affected system study in the phase II SIS results.

The phase II SIS includes a facilities study by the affected transmission owner that identifies any required network upgrades. The facilities studies will include good faith estimates of the costs to be charged to each affected new service customer for the network upgrades that are necessary to accommodate each new service request evaluated in the study, the time required to complete detailed design and construction of the facilities and upgrades and a description of any site-specific environmental issues or requirements that could reasonably be anticipated to affect the cost or time required to complete construction of such facilities and upgrades.

Decision Point II

New service requests that are studied in phase II will enter decision point II. After reviewing the results of the phase II SIS, the project developer must decide whether or not to move forward to phase III of the process. Decision point II starts on the first business day following the end of phase II and closes 30 calendar days later. Before the close of decision point II, the project developer can choose to either remain in the cycle by meeting the decision point II requirements or to withdraw its new service request. If a project developer fails to submit all required deposits, evidence, and data before the close of decision point II, the new service request will be terminated and withdrawn.

Phase III

After the decision point II phase of a cycle is completed and a group of valid new service requests is established, phase III of a cycle will begin. During phase III of a cycle, PJM performs the phase III SIS. PJM retools the load flow, short circuit and stability results from the phase II SIS based on decisions made during decision point II. PJM also coordinates with affected systems to conduct any studies required to determine the final impact of a new service request on any affected system. If applicable and available, PJM includes the results of the affected system operator's final affected system study in the phase III SIS results.

Decision Point III

New service requests that are studied in phase III will enter decision point III. After reviewing the results of the phase III SIS, the project developer must decide whether or not to move forward to the final agreement negotiation phase. Decision point III starts on the first business day following the end of phase III and runs concurrently with the final agreement negotiation phase. The project developer can choose to either remain in the cycle by meeting the decision point III requirements or to withdraw its new service request. If a project developer fails to submit all required deposits, evidence, and data before the close of decision point III, the new service request will be terminated and withdrawn.

Final Agreement Negotiation Phase

The final agreement negotiation phase starts on the first business day immediately following the end of phase III, and runs concurrently with decision point III. The purpose of the final agreement negotiation phase is to negotiate, execute and enter into the applicable final interconnection related service agreement, conduct any remaining analyses or updated analyses based on new service requests withdrawn during decision point III and adjust the security obligation based on new service requests withdrawn during decision point III and/or during the final agreement negotiation phase. PJM uses reasonable efforts to complete the final agreement negotiation phase within 60 days. Table 12-15 is an overview of the agreements used in the new service requests cycle process.

Table 12-15 Final agreements: new service requests cycle process

Agreement	Purpose
Generation Interconnection Agreement (GIA)	The GIA defines the obligations of the project developer regarding cost responsibility for any required system upgrades. The GIA also confers the rights associated with the interconnection of a generating facility as a capacity resource and any operational restrictions or other limitations on which those rights depend. For transmission project developers, the GIA confers transmission injection and withdrawal rights and applicable incremental delivery rights and incremental auction revenue rights.The GIA further identifies any changes in construction responsibility from the standard option for transmission owner interconnection facilities due to the project developer exercising the negotiated contract option or option to build.
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.The CSA is included as a schedule within a GIA; however, a stand-alone CSA may be implemented in circumstances in which network upgrades to the system of a transmission owner are required to accommodate the interconnection request of a project developer, whose facilities do not directly interconnect to the transmission owner's system. Examples include project developers who are affected system customers (external to the PJM region), that require network upgrades to be constructed by PJM transmission owners, or project developers requiring upgrades to be constructed by PJM transmission owners, other than their interconnecting transmission owner
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.
Network Upgrade Cost Responsibility Agreement (NUCRA)	The NUCRA refers to the agreement entered into by two or more project developers and PJM, relating to construction of common use upgrades (network upgrades needed for the interconnection of generating or merchant transmission facilities for more than one project developer that share cost responsibility) and coordination of the construction and interconnection of associated generating facilities. A separate NUCRA will be executed for each set of common use upgrades on the system of a specific transmission owner that is associated with the interconnection of a generating facility or merchant transmission facility. The NUCRA includes the identified common use upgrades scope and schedule of work, the cost responsibility for the project developers that share cost responsibility, as well as the terms and conditions for the agreement.
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 March 31, 2025, 167,067.4 were in generation request queues for construction through 2031. 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.[65]

There were 221,297.3 MW in generation queues, in the status of active, under construction or suspended, at the end of 2024. As projects move through the queue process, projects can be removed from the queue due to incomplete or invalid data, withdrawn by the market participant or placed in service. On March 31, 2025, there were 167,067.4 MW in generation queues, in the status of active, under construction or suspended, a decrease of 54,229.9 MW (24.5 percent) from December 31, 2024. Table 12-16 shows MW in queues by expected completion year and MW changes in the queue between December 31, 2024, and March 31, 2025, for ongoing projects, i.e. projects with the status active, under construction or suspended.[66]

Table 12-16 Queue comparison by expected completion year (MW): December 31, 2024 and March 31, 2025[67]

			Year Change	
Year	As of 12/31/2024	As of 3/31/2025	MW	Percent
2008	0.0	0.0	0.0	0.0%
2009	0.0	0.0	0.0	0.0%
2010	0.0	0.0	0.0	0.0%
2011	0.0	0.0	0.0	0.0%
2012	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	0.0	0.0	0.0	0.0%
2017	0.0	0.0	0.0	0.0%
2018	44.0	44.0	0.0	0.0%
2019	69.1	18.0	(51.1)	(74.0%)
2020	517.6	122.0	(395.6)	(76.4%)
2021	3,909.3	2,554.8	(1,354.5)	(34.6%)
2022	8,805.0	5,731.2	(3,073.8)	(34.9%)
2023	16,502.7	14,196.6	(2,306.0)	(14.0%)
2024	31,170.4	29,452.1	(1,718.3)	(5.5%)
2025	33,849.0	32,197.9	(1,651.1)	(4.9%)
2026	29,556.2	30,545.7	989.5	3.3%
2027	17,693.5	22,187.9	4,494.4	25.4%
2028	10,052.1	12,775.3	2,723.2	27.1%
2029	8,733.6	9,607.6	874.0	10.0%
2030	4,020.9	5,050.9	1,030.0	25.6%
2031	2,144.0	2,583.4	439.4	20.5%
Total	167,067.4	167,067.4	0.0	0.0%

65 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>.

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

67 Wind and solar capacity in Table 12-16 through Table 12-21 have not been adjusted to reflect derating.

Table 12-17 shows the project status changes in more detail and how scheduled queue MW have changed between December 31, 2024, and March 31, 2025. For example, of the total 198,934.9 MW marked as active on December 31, 2024, 49,209.8 MW were withdrawn, 132.0 MW were suspended, 2,200.8 MW started construction, and 0.0 MW went into service by March 31, 2025. Analysis of projects that were suspended on December 31, 2024 show that 742.3 MW came out of suspension and are now active as of March 31, 2025.

Table 12-17 Change in project status (MW): December 31, 2024, to March 31, 2025

		Status at 3/31/2025				
Status at 12/31/2024	Total at 12/31/2024	Active	In Service	Under Construction	Suspended	Withdrawn
(Entered during 2025)	0.0	0.0	0.0	0.0	0.0	0.0
Active	198,934.9	147,392.3	0.0	2,200.8	132.0	49,209.8
In Service	91,789.6	0.0	91,789.6	0.0	0.0	0.0
Under Construction	6,862.9	0.0	1,331.8	5,429.1	90.0	12.0
Suspended	12,137.9	742.3	0.0	78.2	10,997.6	319.9
Withdrawn	514,371.0	5.3	8.0	0.0	0.0	514,357.7
Total	824,096.3	148,139.8	93,129.4	7,708.0	11,219.6	563,899.4

On March 31, 2025, 167,067.4 were in generation request queues in the status of active, suspended or under construction. Table 12-18 shows each status by unit type. Of the 148,139.8 MW in the status of active on March 31, 2025, 3,576.0 MW (2.4 percent) were combined cycle projects. Of the 7,708.0 MW in the status of under construction, 2,243.8 MW (29.1 percent) were combined cycle projects and 3,410.6 MW (44.2 percent) were solar 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 148,139.8 MW in the status of active on March 31, 2025, 18,977.0 MW (12.8 percent) were renewable hybrid projects. Of the 7,708.0 MW in the status of under construction, 314.8 MW (4.1 percent) were renewable hybrid projects.

Table 12-18 Current project status (MW) by unit type: March 31, 2025

	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	36,336.5	3,576.0	1,829.7	0.0	28.0	5.0	0.0	87.1	0.0	0.0	0.0	0.0	65,180.7	18,827.0	0.0	0.0	0.0	0.0	20.1	22,099.9	150.0	148,139.8
Suspended	642.9	1,845.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7,107.5	17.5	0.0	0.0	0.0	0.0	0.0	1,606.7	0.0	11,219.6
Under Construction	21.0	2,243.8	60.0	0.0	0.0	0.0	0.0	0.0	44.0	0.0	0.0	0.0	3,410.6	314.8	0.0	65.0	0.0	0.0	0.0	1,548.9	0.0	7,708.0
Total	37,000.4	7,664.8	1,889.7	0.0	28.0	5.0	0.0	87.1	44.0	0.0	0.0	0.0	75,698.7	19,159.2	0.0	65.0	0.0	0.0	20.1	25,255.5	150.0	167,067.4

A significant shift in the distribution of unit types within the PJM footprint continues to develop as renewable, hybrid and other intermittent resources enter the queue, fewer natural gas fired units enter the queue, and coal fired steam units retire. As of March 31, 2025, of the 167,067.4 MW in the generation request queues in the status of active, suspended or under construction, 75,698.7 MW (45.3 percent) were solar projects, 25,255.5 MW (15.1 percent) were wind projects, 9,554.5 MW (5.7 percent) were natural gas fired projects (including combined cycle units, CTs, RICE units, and natural gas fired steam units), 19,309.2 MW (11.6 percent) were renewable hybrid projects (solar + storage, solar + wind and wind + storage units), and 65.0 MW (.04 percent) were coal fired steam projects.

As of March 31, 2025, there are 3,893.0 MW of coal fired steam units and 3,006.0 MW of natural gas units slated for deactivation between April 1, 2025, and December 31, 2028 (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 have increasingly significant impacts on the energy and capacity markets.

On March 31, 2025, 37,355.2 MW, on an energy basis, were in generation request queues that had reached the construction service agreement milestone or equivalent, in the status of active, suspended or under construction. Table 12-19 shows the status by unit type. Of the 37,355.2 MW, 18,572.4 MW (49.7 percent) had not begun construction, 11,219.6 MW (30.0 percent) began construction, but are now suspended and 7,563.2 MW (20.2 percent) are currently under construction. Reaching the final milestone required prior to construction does not mean a project will immediately begin construction or even that it necessarily will ever begin construction.

Table 12-19 Current status (MW) by unit type for projects that have reached the CSA Milestone: March 31, 2025

	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	1,101.0	1,164.0	618.3	0.0	0.0	0.0	0.0	16.8	0.0	0.0	0.0	0.0	9,680.5	1,409.7	0.0	0.0	0.0	0.0	0.0	4,582.1	0.0	18,572.4
Suspended	642.9	1,845.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7,107.5	17.5	0.0	0.0	0.0	0.0	0.0	1,606.7	0.0	11,219.6
Under Construction	21.0	2,243.8	60.0	0.0	0.0	0.0	0.0	0.0	44.0	0.0	0.0	0.0	3,265.8	314.8	0.0	65.0	0.0	0.0	0.0	1,548.9	0.0	7,563.2
Total	1,764.9	5,252.8	678.3	0.0	0.0	0.0	0.0	16.8	44.0	0.0	0.0	0.0	20,053.8	1,742.0	0.0	65.0	0.0	0.0	0.0	7,737.6	0.0	37,355.2

Table 12-20 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 projects in queues A-R are either in service or have been withdrawn. As of March 31, 2025, there are 167,067.4 MW in queues that are not yet in service or withdrawn, of which 11,219.6 MW (6.7 percent) are suspended, 7,708.0 MW (4.6 percent) are under construction and 148,139.8 MW (88.7 percent) have not begun construction.

Table 12-20 Queue totals by status (MW): March 31, 2025[68]

Queue	Active	In Service	Under Construction	Suspended	Withdrawn	Total
A Expired 31-Jan-98	0.0	9,102.0	0.0	0.0	17,252.0	26,354.0
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	0.0	3,543.5	54.9	0.0	12,396.5	15,994.9
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	0.0	0.0	3,641.2	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	505.5	0.0	0.0	8,695.9	9,201.4
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	1,634.5	0.0	0.0	4,605.2	6,239.6
Z1 Expired 31-Oct-13	0.0	3,283.5	0.0	0.0	4,730.0	8,013.5
Z2 Expired 30-Apr-14	0.0	3,058.6	0.0	0.0	3,037.8	6,096.5
AA1 Expired 31-Oct-14	0.0	4,868.9	228.2	0.0	6,973.4	12,070.5
AA2 Expired 30-Apr-15	550.0	3,031.6	0.0	0.0	12,484.7	16,066.3
AB1 Expired 31-Oct-15	286.8	2,800.6	2,126.0	575.0	14,665.3	20,453.7
AB2 Expired 31-Mar-16	294.0	3,614.5	266.0	0.0	10,968.3	15,142.8
AC1 Expired 30-Sep-16	592.3	5,490.2	515.8	1,038.7	12,399.0	20,035.9
AC2 Expired 30-Apr-17	923.4	1,312.8	570.8	374.9	9,387.8	12,569.6
AD1 Expired 30-Sep-17	747.0	1,295.7	1,326.7	940.0	6,927.2	11,236.6
AD2 Expired 31-Mar-18	472.0	1,703.1	697.4	1,464.8	15,801.3	20,138.6
AE1 Expired 30-Sep-18	3,997.6	784.4	207.4	3,771.8	24,782.1	33,543.2
AE2 Expired 31-Mar-19	6,228.2	1,600.6	654.9	2,255.9	22,895.4	33,635.0
AF1 Expired 30-Sep-19	10,036.9	1,021.7	772.8	554.7	16,059.1	28,445.1
AF2 Expired 31-Mar-20	10,686.9	332.7	221.0	153.8	16,357.0	27,751.3
AG1 Expired 30-Sep-20	11,598.9	36.8	66.2	90.0	24,838.6	36,630.5
AG2 Expired 31-Mar-21	25,912.6	1.0	0.0	0.0	28,125.2	54,038.7
AH1 Expired 10-Sep-21	19,237.0	0.0	0.0	0.0	30,261.7	49,498.7
AH2 Expired 10-Mar-22	24,043.7	0.0	0.0	0.0	10,301.8	34,345.5
AI1 Expired 10-Sep-22	20,260.3	0.0	0.0	0.0	3,429.7	23,690.0
AI2 Expired 10-Mar-23	7,799.4	0.0	0.0	0.0	422.0	8,221.4
AJ1 Expired 10-Sep-23	4,473.0	0.0	0.0	0.0	0.0	4,473.0
Total	148,139.8	93,129.4	7,708.0	11,219.6	563,899.4	824,096.3

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

Table 12-21 shows the projects with a status of active, suspended or under construction, by unit type, and control zone. As of March 31, 2025, 167,067.4 MW were in generation request queues for construction through 2031. Table 12-21 also shows the planned retirements for each zone.

Table 12-21 Queue totals for projects (active, suspended and under construction) by LDA, control zone and unit type (MW): March 31, 2025[69]

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	1,617.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	451.3	83.0	0.0	0.0	0.0	0.0	0.0	432.0	0.0	2,583.6	177.6
	DPL	540.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,536.6	207.3	0.0	0.0	0.0	0.0	10.0	771.9	0.0	3,065.8	16.4
	JCPLC	1,340.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	595.6	140.0	0.0	0.0	0.0	0.0	0.0	10,616.9	0.0	12,692.5	79.1
	PECO	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	44.0	0.0	0.0	0.0	49.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	93.8	762.0
	PSEG	910.0	51.1	0.0	0.0	0.0	0.0	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	1,310.0	0.0	2,287.1	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	4,407.3	51.1	0.0	0.0	0.0	0.0	0.0	0.0	44.0	0.0	0.0	0.0	2,649.2	430.3	0.0	0.0	0.0	0.0	10.0	13,130.8	0.0	20,722.7	1,035.1
SWMAAC	BGE	1,195.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	85.0	50.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,330.0	2,113.9
	PEPCO	2,117.0	45.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	175.0	670.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3,007.2	0.0
	SWMAAC Total	3,312.0	45.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	260.0	720.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4,337.2	2,113.9
WMAAC	MEC	615.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	314.6	201.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,130.9	0.0
	PE	840.0	30.0	0.0	0.0	3.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3,882.9	1,218.8	0.0	0.0	0.0	0.0	0.0	436.7	0.0	6,411.9	0.0
	PPL	170.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,399.4	366.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,935.6	0.0
	WMAAC Total	1,625.0	30.0	0.0	0.0	3.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5,596.9	1,786.3	0.0	0.0	0.0	0.0	0.0	436.7	0.0	9,478.4	0.0
Non-MAAC	AEP	7,240.5	1,150.0	772.0	0.0	14.2	0.0	0.0	51.0	0.0	0.0	0.0	0.0	28,502.5	7,509.4	0.0	65.0	0.0	0.0	10.1	1,941.2	0.0	47,255.9	2,700.0
	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	40.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	40.0	0.0
	APS	2,372.9	4,055.0	30.0	0.0	0.0	0.0	0.0	14.0	0.0	0.0	0.0	0.0	3,364.2	1,986.0	0.0	0.0	0.0	0.0	0.0	1,014.0	0.0	12,836.1	0.0
	ATSI	838.0	1,068.0	458.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3,453.7	316.6	0.0	0.0	0.0	0.0	0.0	297.7	0.0	6,432.7	0.0
	COMED	7,780.4	677.7	60.0	0.0	0.0	5.0	0.0	0.0	0.0	0.0	0.0	0.0	10,199.7	1,586.6	0.0	0.0	0.0	0.0	0.0	5,067.8	0.0	25,377.2	1,799.9
	DAY	248.0	0.0	0.0	0.0	10.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,559.5	351.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,169.5	0.0
	DUKE	302.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	149.0	800.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,251.2	6.0
	DLCO	50.0	0.0	0.0	0.0	0.0	0.0	0.0	22.1	0.0	0.0	0.0	0.0	34.7	87.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	194.3	0.0
	DOM	8,726.1	588.0	569.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	15,794.4	2,556.4	0.0	0.0	0.0	0.0	0.0	3,367.3	150.0	31,751.2	0.0
	EKPC	98.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3,696.5	1,028.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4,822.6	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	398.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	398.5	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	27,656.1	7,538.7	1,889.7	0.0	24.4	5.0	0.0	87.1	0.0	0.0	0.0	0.0	67,192.6	16,222.4	0.0	65.0	0.0	0.0	10.1	11,688.0	150.0	132,529.1	4,505.9
Total		37,000.4	7,664.8	1,889.7	0.0	28.0	5.0	0.0	87.1	44.0	0.0	0.0	0.0	75,698.7	19,159.2	0.0	65.0	0.0	0.0	20.1	25,255.5	150.0	167,067.4	7,654.9

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.[70] 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 12-22 and Table 12-23.

Table 12-22 shows the milestone status when projects were withdrawn, for all withdrawn projects. Of the 4,915 projects withdrawn as of March 31, 2025, 2,698 (54.9 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 4,915 projects withdrawn, 815 projects (16.6 percent) were withdrawn after the completion of a Construction Service Agreement as of March 31, 2025.

69 This data includes only projects with a status of active, under construction, or suspended.
70 See "PJM Manual 14B: PJM Region Transmission Planning Process," Rev. 57 (September 25, 2024).

Table 12-22 Last milestone at time of withdrawal: January 1, 1997 through March 31, 2025

Milestone Completed	Projects Withdrawn	Percent	Average Days	Maximum Days	MW Withdrawn
Never Started	1,540	31.3%	125,680	1,006	3,173.0
Feasibility Study	1,158	23.6%	208,186	390	1,967.0
System Impact Study	995	20.2%	126,060	903	3,248.0
Facilities Study	407	8.3%	56,758	1,263	4,107.0
Construction Service Agreement (CSA) or beyond	815	16.6%	47,216	1,463	7,864.0
Total	4,915	100.0%			20,359.0

Average Time in Queue

Table 12-23 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 1,234 days, or 3.4 years, between entering a queue and going into service. For withdrawn projects, there is an average time of 850 days, or 2.3 years, between entering a queue and withdrawing.

Table 12-23 Project queue times by status (days): March 31, 2025[71]

Status	Average (Days)	Standard Deviation	Maximum
Active	1,316	501	3,623
In-Service	1,234	847	5,306
Suspended	2,357	403	3,470
Under Construction	2,623	693	6,586
Withdrawn	850	737	7,864

Table 12-24 presents information on the time in the stages of the queue for those projects not yet in service or already withdrawn. Of the 2,031 projects in the queue, in the status of active, under construction or suspended, as of March 31, 2025, 31 (1.5 percent) had a completed feasibility study and 391 (19.3 percent) had a completed construction service agreement.

Table 12-24 Project queue times by milestone (days): March 31, 2025

Milestone Reached	Number of Projects	Percent of Total Projects	Average Days	Maximum Days
Under Review	1,375	67.7%	2,961	4,021
Feasibility Study	31	1.5%	1,676	1,836
System Impact Study	95	4.7%	1,882	2,404
Facilities Study	139	6.8%	1,879	2,380
Construction Service Agreement (CSA) or beyond	391	19.3%	2,354	6,586
Total	2,031	100.0%		

71 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 12-25 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 2,062 days from the time it entered the queue until it went in service, compared to 1,409 days when entering the queue in 2018.

Table 12-25 Average time in queue (days) by fuel type and year submitted (In Service Projects): March 31, 2025[72]

Unit Type	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Battery	983	609	417	710	789	2,062	941		1,409	972	1,084			
CC	1,310	1,551	1,663	1,419	1,175	1,208	1,199	1,013	1,140	1,069	1,634			
CT - Natural Gas	1,131	804	953	1,073	1,409	619	1,566	1,192	938	317	805			
CT - Oil	717		259							280	349			
CT - Other	729	634	954	1,248	718	360								
Fuel Cell						827				280				
Hydro - Pumped Storage						1,402								
Hydro - Run of River			1,325	614	332		580	426	606					
Nuclear	885	866		1,234			2,409	1,100	1,747					
RICE - Natural Gas			1,702	1,053	1,332	798		250		770				
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	1,761	1,887	1,928	1,707	1,425	915			
Solar + Storage						635	322		553		1,176			
Solar + Wind														
Steam - Coal	745		513	1,010	583	853	684	647	1,122					
Steam - Natural Gas				1,182		421	751				1,217			
Steam - Oil														
Steam - Other	256	838	643											
WInd	2,748	2,711	1,750	2,103	1,205	1,463	1,620	1,398	1,289		997			
Wind + Storage							2,680							

72 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.

Table 12-26 shows 824,096.3 MW have entered PJM generation queues from January 1, 1997, through March 31, 2025. Table 12-26 presents totals by fuel type and projected in service date as of March 31, 2025. Of the 824,096.3 MW to enter the queue, 351,914.3 MW (42.7 percent) were thermal units.

Table 12-26 Total (MW Energy) by unit type and projected in service year: March 31, 2025

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	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	4,911.0	0.0	0.0	0.0	0.0	0.0	5,686.0
1998	0.0	4,659.0	0.0	0.0	3.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4,662.1
1999	0.0	22,573.7	2.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7.0	0.0	0.0	0.0	20.4	0.0	22,603.2
2000	0.0	9,900.8	409.6	0.0	3.8	0.0	0.0	0.0	0.0	0.0	0.0	1.2	0.0	0.0	0.0	20.0	0.0	0.0	0.0	0.0	0.0	10,335.3
2001	0.0	7,088.5	432.0	315.0	29.0	0.0	0.0	0.0	165.0	0.0	0.0	0.0	0.0	0.0	0.0	110.6	2.5	0.0	0.0	0.0	0.0	8,142.6
2002	0.0	2,622.2	2,442.0	6.5	0.0	0.0	0.0	107.0	60.0	0.0	0.0	2.9	0.0	0.0	0.0	42.0	10.0	0.0	0.0	65.5	0.0	5,358.1
2003	0.0	4,072.1	638.7	0.0	59.4	0.0	0.0	198.0	46.0	0.0	0.0	17.2	0.0	0.0	0.0	2.0	0.0	0.0	0.0	263.6	0.0	5,297.0
2004	0.0	14,918.2	77.3	33.0	16.1	0.0	0.0	41.0	0.0	8.0	23.3	0.0	0.0	0.0	0.0	42.0	0.0	0.0	0.0	75.0	0.0	15,233.9
2005	0.0	17,149.1	993.0	251.0	42.1	0.0	0.0	0.0	1,693.0	29.0	5.0	7.5	0.0	0.0	0.0	1,880.0	0.0	0.0	0.0	809.9	0.0	22,859.6
2006	0.0	6,033.0	23.3	49.5	43.4	0.0	0.0	147.2	0.0	2.0	30.5	58.5	0.0	0.0	0.0	527.0	0.0	0.0	529.0	1,480.2	0.0	8,923.6
2007	0.0	3,484.6	131.0	17.0	84.0	0.0	0.0	2.5	174.0	19.5	0.0	86.6	0.0	0.0	0.0	750.0	5.0	0.0	68.0	1,087.8	0.0	5,910.0
2008	1.0	7,003.4	628.0	59.3	38.4	0.0	0.0	2.9	331.0	0.0	0.0	57.6	3.3	0.0	0.0	254.5	101.0	0.0	20.0	2,103.2	0.0	10,603.6
2009	120.0	2,717.2	257.7	108.6	118.7	0.0	340.0	252.5	0.0	0.0	0.0	41.2	28.7	0.0	0.0	1,058.0	40.0	0.0	6.0	4,351.5	0.0	9,440.2
2010	16.0	1,912.9	137.8	83.9	320.7	0.0	16.0	94.9	301.0	10.5	0.0	15.8	231.4	0.0	0.0	5,599.0	0.0	0.0	80.8	9,286.1	0.0	18,106.8
2011	52.5	10,887.5	816.4	23.0	110.0	0.0	0.0	27.0	512.0	0.0	16.0	41.8	1,818.5	0.0	0.0	9,614.0	5.5	0.0	108.9	5,355.2	0.0	29,388.2
2012	27.0	13,786.8	389.5	310.0	121.3	0.0	0.0	82.9	391.0	0.0	6.4	2.0	1,892.3	0.0	0.0	3,407.0	0.0	0.0	426.6	7,689.5	0.0	28,532.2
2013	73.0	9,252.2	62.5	730.5	78.9	0.0	0.0	219.0	238.0	0.0	10.0	113.0	674.9	0.0	0.0	1,949.0	44.0	0.0	254.1	8,057.4	0.0	21,756.5
2014	159.1	7,105.5	0.0	684.0	96.0	0.0	0.0	1,120.0	74.0	0.0	0.0	13.3	904.5	0.0	0.0	3,288.0	0.0	0.0	63.8	11,758.7	186.0	25,452.9
2015	214.6	15,591.3	417.4	42.0	21.9	0.0	0.0	378.5	147.8	19.5	9.0	3.8	1,240.1	0.0	0.0	1,271.5	0.0	0.0	81.5	4,161.6	0.0	23,600.4
2016	422.5	16,553.3	332.1	0.0	144.9	2.8	0.0	71.2	4,082.0	46.9	0.0	30.2	1,737.6	3.4	0.0	50.0	40.0	0.0	107.8	4,459.3	0.0	28,083.9
2017	134.1	17,489.5	835.0	401.0	135.0	2.0	0.0	38.2	1,640.0	283.6	0.0	18.2	2,158.3	0.0	0.0	47.0	606.5	0.0	7.2	3,010.2	0.0	26,805.7
2018	175.0	17,902.0	404.9	0.0	11.6	1.1	34.0	12.5	1,644.0	95.0	0.0	41.0	3,371.1	0.6	0.0	148.0	57.0	0.0	0.0	5,135.7	0.0	29,033.5
2019	303.0	14,752.4	1,036.8	14.0	0.0	0.0	0.0	20.5	0.0	79.7	0.0	33.6	7,221.3	629.8	0.0	1,710.0	0.0	0.0	16.0	5,377.6	16.3	31,210.9
2020	621.7	7,243.7	1,173.0	0.0	0.0	2.1	0.0	2.4	128.0	39.9	4.0	0.8	5,846.6	615.5	0.0	20.0	64.0	0.0	0.0	8,886.7	0.0	24,648.4
2021	1,356.9	17,904.2	687.3	4.0	0.0	0.0	0.0	99.0	0.0	15.7	0.0	0.0	15,931.7	2,545.0	0.0	47.0	6.0	0.0	62.5	5,249.5	90.0	43,998.7
2022	4,985.9	12,805.2	1,701.3	0.0	6.0	0.0	1,030.0	33.2	0.0	34.4	6.6	0.0	18,473.5	4,221.0	10.0	0.0	0.0	0.0	0.0	3,504.6	0.0	46,811.6
2023	12,482.6	12,674.0	1,441.6	13.0	3.6	3.0	0.0	53.8	54.2	0.0	0.0	0.0	30,083.2	9,964.1	199.0	0.0	0.0	0.0	30.1	3,024.5	0.0	70,026.7
2024	12,426.7	4,650.5	646.0	0.0	363.5	0.0	0.0	12.0	1,594.0	0.0	0.0	0.0	37,193.8	6,753.8	0.0	18.0	5.0	0.0	0.0	7,195.3	0.0	70,858.6
2025	12,838.5	1,163.7	463.0	0.0	0.0	5.0	0.0	16.8	0.0	0.0	0.0	0.0	26,918.9	6,239.1	0.0	11.0	0.0	0.0	0.0	7,301.7	0.0	54,957.7
2026	7,712.0	4,041.1	700.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	15,008.2	4,725.7	0.0	0.0	0.0	0.0	10.0	7,272.4	150.0	39,619.4
2027	8,095.2	1,775.0	735.0	0.0	0.0	0.0	200.0	0.0	0.0	0.0	0.0	0.0	9,917.0	2,783.7	0.0	0.0	0.0	0.0	0.0	9,625.7	0.0	33,131.6
2028	4,524.0	645.0	49.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6,577.9	2,457.0	0.0	0.0	0.0	0.0	0.0	2,273.1	0.0	16,526.3
2029	1,110.0	0.0	569.0	0.0	0.0	0.0	0.0	9.5	0.0	0.0	0.0	0.0	1,815.6	683.0	0.0	0.0	0.0	0.0	0.0	12,999.8	0.0	17,186.9
2030	250.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,390.0	0.0	0.0	0.0	0.0	0.0	0.0	3,480.9	0.0	5,120.9
2031	0.0	0.0	439.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	150.0	394.0	0.0	0.0	0.0	0.0	0.0	3,200.0	0.0	4,183.4
Total	68,101.1	291,132.5	19,072.0	3,145.3	1,851.3	15.9	1,620.0	3,042.4	13,275.0	683.7	110.8	586.2	190,588.5	42,015.6	209.0	36,783.6	986.5	0.0	1,872.2	148,562.3	442.3	824,096.3

Table 12-27 shows there are 167,067.4 MW in the queue in the status of active, under construction and suspended as of March 31, 2025. Table 12-27 presents totals by fuel type and projected in service date. Of the 167,067.4 MW, 9,619.5 MW (5.8 percent) are thermal units. Of the 114,948.7 MW with projected in service dates between 2025 and 2031, 8,737.5 MW (5.2 percent) are thermal units.

Table 12-27 Total (MW Energy) by unit type and projected in service year (active, under construction and suspended): March 31, 2025

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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1998	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1999	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2000	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2001	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2002	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2003	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2004	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2005	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2006	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2007	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2008	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2009	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2010	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2011	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2012	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2013	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2014	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2015	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2016	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2017	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2018	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	44.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	44.0
2019	0.0	0.0	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	0.0	0.0	0.0	0.0	18.0
2020	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	122.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	122.0
2021	120.0	0.0	0.0	0.0	0.0	0.0	0.0	51.0	0.0	0.0	0.0	0.0	1,831.2	23.2	0.0	36.0	0.0	0.0	0.0	493.4	0.0	2,554.8
2022	856.4	77.0	72.0	0.0	0.0	0.0	0.0	5.3	0.0	0.0	0.0	0.0	3,236.7	741.0	0.0	0.0	0.0	0.0	0.0	742.9	0.0	5,731.2
2023	3,299.9	569.0	0.0	0.0	3.6	0.0	0.0	14.0	0.0	0.0	0.0	0.0	7,690.4	2,109.7	0.0	0.0	0.0	0.0	10.1	500.0	0.0	14,196.6
2024	6,512.8	110.0	0.0	0.0	24.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	18,024.5	3,165.5	0.0	18.0	0.0	0.0	0.0	1,597.0	0.0	29,452.1
2025	7,787.6	1,072.7	0.0	0.0	0.0	5.0	0.0	16.8	0.0	0.0	0.0	0.0	16,275.0	3,191.4	0.0	11.0	0.0	0.0	0.0	3,838.5	0.0	32,197.9
2026	6,744.0	4,041.1	700.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10,609.0	3,784.4	0.0	0.0	0.0	0.0	10.0	4,507.2	150.0	30,545.7
2027	7,245.7	1,150.0	60.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	9,369.5	2,610.2	0.0	0.0	0.0	0.0	0.0	1,752.5	0.0	22,187.9
2028	3,374.0	645.0	49.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5,736.9	2,457.0	0.0	0.0	0.0	0.0	0.0	513.1	0.0	12,775.3
2029	810.0	0.0	569.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,315.6	683.0	0.0	0.0	0.0	0.0	0.0	6,230.0	0.0	9,607.6
2030	250.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,320.0	0.0	0.0	0.0	0.0	0.0	0.0	3,480.9	0.0	5,050.9
2031	0.0	0.0	439.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	150.0	394.0	0.0	0.0	0.0	0.0	0.0	1,600.0	0.0	2,583.4
Total	37,000.4	7,664.8	1,889.7	0.0	28.0	5.0	0.0	87.1	44.0	0.0	0.0	0.0	75,698.7	19,159.2	0.0	65.0	0.0	0.0	20.1	25,255.5	150.0	167,067.4

Table 12-28 shows there were 563,899.4 MW withdrawn from the queue from January 1, 1997, through March 31, 2025. Table 12-28 presents totals by fuel type and projected in service date. Of the 563,899.4 MW withdrawn from the queue, 279,754.1 MW (49.6 percent) were thermal units. Of the 54,874.8 MW withdrawn with projected in service dates between 2025 and 2031, 1,854.0 MW (3.4 percent) were thermal units.

Table 12-28 Total (MW Energy) by unit type and projected in service year (withdrawn): March 31, 2025

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	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	4,911.0	0.0	0.0	0.0	0.0	0.0	5,686.0
1998	0.0	4,659.0	0.0	0.0	3.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4,662.1
1999	0.0	22,573.7	2.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	22,575.8
2000	0.0	9,900.8	0.0	0.0	3.8	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	9,904.5
2001	0.0	6,988.5	0.0	0.0	5.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	51.6	0.0	0.0	0.0	0.0	0.0	7,045.1
2002	0.0	14.2	0.0	0.0	0.0	0.0	0.0	0.0	45.0	0.0	0.0	0.0	0.0	0.0	0.0	28.0	0.0	0.0	0.0	50.5	0.0	137.7
2003	0.0	1,287.1	0.0	0.0	59.4	0.0	0.0	0.0	2.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	73.6	0.0	1,422.1
2004	0.0	12,073.2	0.0	0.0	12.0	0.0	0.0	41.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	75.0	0.0	12,201.2
2005	0.0	17,134.0	0.0	1.0	42.1	0.0	0.0	0.0	0.0	0.0	5.0	0.0	0.0	0.0	0.0	1,860.0	0.0	0.0	0.0	802.4	0.0	19,844.5
2006	0.0	4,847.0	0.0	0.0	43.4	0.0	0.0	142.0	0.0	0.0	30.5	0.0	0.0	0.0	0.0	520.0	0.0	0.0	0.0	1,430.2	0.0	7,013.1
2007	0.0	3,455.0	0.0	0.0	71.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	675.0	0.0	0.0	50.0	554.5	0.0	4,805.6
2008	1.0	6,826.0	0.0	0.0	38.4	0.0	0.0	2.9	18.0	0.0	0.0	0.0	0.0	0.0	0.0	152.0	0.0	0.0	0.0	1,857.0	0.0	8,895.3
2009	120.0	2,618.2	0.0	61.0	113.7	0.0	0.0	252.0	0.0	0.0	0.0	0.0	28.7	0.0	0.0	935.0	0.0	0.0	6.0	3,129.5	0.0	7,264.1
2010	16.0	1,776.9	0.0	81.0	302.5	0.0	0.0	54.9	0.0	0.0	0.0	0.0	168.5	0.0	0.0	5,512.0	0.0	0.0	20.8	7,853.1	0.0	15,785.7
2011	25.1	8,985.5	0.0	0.0	98.6	0.0	0.0	0.0	140.0	0.0	16.0	0.0	1,747.5	0.0	0.0	8,817.0	0.0	0.0	108.0	4,781.0	0.0	24,718.7
2012	20.5	13,711.5	0.5	310.0	87.7	0.0	0.0	82.9	0.0	0.0	6.4	0.0	1,801.8	0.0	0.0	2,751.0	0.0	0.0	426.6	6,535.0	0.0	25,733.9
2013	72.0	9,168.0	0.0	730.0	38.6	0.0	0.0	79.0	34.0	0.0	10.0	0.0	651.0	0.0	0.0	1,861.0	0.0	0.0	254.1	7,686.3	0.0	20,584.1
2014	114.1	6,438.0	0.0	684.0	96.0	0.0	0.0	1,085.1	74.0	0.0	0.0	0.0	809.7	0.0	0.0	3,212.0	0.0	0.0	10.0	11,308.7	0.0	23,831.6
2015	111.6	13,216.5	12.5	42.0	10.7	0.0	0.0	218.0	0.0	0.6	9.0	0.0	1,041.4	0.0	0.0	1,251.0	0.0	0.0	81.5	3,956.6	0.0	19,951.4
2016	400.1	9,812.3	35.4	0.0	144.0	2.0	0.0	71.2	3,980.0	26.0	0.0	11.7	1,484.8	0.0	0.0	50.0	0.0	0.0	107.8	4,181.8	0.0	20,307.1
2017	134.1	13,041.4	696.0	401.0	135.0	1.3	0.0	15.0	1,640.0	263.7	0.0	17.1	1,822.2	0.0	0.0	0.0	0.0	0.0	7.2	2,375.2	0.0	20,549.1
2018	109.5	10,224.0	64.9	0.0	11.6	1.1	0.0	0.0	1,600.0	89.8	0.0	36.2	3,017.5	0.0	0.0	80.0	27.0	0.0	0.0	4,618.0	0.0	19,879.6
2019	303.0	10,771.9	922.8	14.0	0.0	0.0	0.0	15.0	0.0	39.9	0.0	33.6	6,771.8	629.8	0.0	1,710.0	0.0	0.0	16.0	4,286.6	16.3	25,530.6
2020	621.7	5,987.7	1,022.0	0.0	0.0	2.1	0.0	0.0	100.0	39.9	0.0	0.0	4,789.8	614.4	0.0	20.0	0.0	0.0	0.0	7,786.4	0.0	20,984.0
2021	1,235.4	14,345.5	330.3	0.0	0.0	0.0	0.0	48.0	0.0	1.3	0.0	0.0	12,981.0	2,521.8	0.0	0.0	6.0	0.0	0.0	4,196.1	90.0	35,755.4
2022	4,102.7	8,417.3	1,533.8	0.0	6.0	0.0	1,030.0	28.0	0.0	34.4	6.6	0.0	13,811.2	3,480.0	10.0	0.0	0.0	0.0	0.0	2,761.7	0.0	35,221.6
2023	9,127.7	10,861.0	851.5	0.0	0.0	0.0	0.0	39.8	0.0	0.0	0.0	0.0	19,422.7	7,837.5	199.0	0.0	0.0	0.0	20.0	2,242.1	0.0	50,601.3
2024	5,911.4	4,540.5	646.0	0.0	339.1	0.0	0.0	12.0	1,594.0	0.0	0.0	0.0	16,004.9	3,588.4	0.0	0.0	0.0	0.0	0.0	5,497.5	0.0	38,133.7
2025	5,030.9	91.0	463.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	9,950.3	3,047.7	0.0	0.0	0.0	0.0	0.0	3,274.2	0.0	21,857.1
2026	968.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4,399.2	941.3	0.0	0.0	0.0	0.0	0.0	2,765.2	0.0	9,073.7
2027	849.5	625.0	675.0	0.0	0.0	0.0	200.0	0.0	0.0	0.0	0.0	0.0	547.5	173.5	0.0	0.0	0.0	0.0	0.0	7,873.2	0.0	10,943.7
2028	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	841.0	0.0	0.0	0.0	0.0	0.0	0.0	1,760.0	0.0	3,751.0
2029	300.0	0.0	0.0	0.0	0.0	0.0	0.0	9.5	0.0	0.0	0.0	0.0	500.0	0.0	0.0	0.0	0.0	0.0	0.0	6,769.8	0.0	7,579.3
2030	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	70.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	70.0
2031	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,600.0	0.0	1,600.0
Total	30,724.1	235,165.6	7,255.8	2,324.0	1,661.8	6.4	1,230.0	2,196.3	9,227.0	495.6	83.5	98.6	102,662.6	22,834.3	209.0	34,396.6	33.0	0.0	1,108.0	112,080.9	106.3	563,899.4

Completion Rates

The probability of a project going into service increases as each step of the planning process is completed. Table 12-29 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.[73] 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, 5.3 percent of the queued MW have gone into service. The completion rate for battery projects increases to 19.2 percent when battery projects complete the facility study agreement and further increases to 39.3 percent when battery projects complete the construction service agreement. Of all battery projects to enter the queue, only 0.5 percent of the queued MW have gone into service.

73 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 12-29 Historic completion rates (MW energy) by unit type for projects with a completed SIS, FSA and CSA: March 31, 2025

Unit Type	Completion Rate (SIS)	Completion Rate (FSA)	Completion Rate (CSA)	Completion Rate (ALL)
Battery	5.3%	19.2%	39.3%	0.5%
CC	34.0%	49.8%	72.0%	16.4%
CT - Natural Gas	59.3%	70.4%	72.2%	47.9%
CT - Oil	35.7%	60.0%	90.9%	25.4%
CT - Other	12.1%	18.4%	29.5%	8.4%
Fuel Cell	50.6%	51.8%	51.8%	28.4%
Hydro - Pumped Storage	35.8%	35.8%	66.1%	24.1%
Hydro - Run of River	41.9%	58.8%	65.7%	20.9%
Nuclear	34.7%	41.9%	51.3%	28.5%
RICE - Natural Gas	32.4%	44.7%	49.4%	27.4%
RICE - Oil	34.0%	59.7%	59.7%	24.6%
RICE - Other	88.9%	91.3%	92.0%	77.9%
Solar	24.8%	45.7%	63.9%	6.6%
Solar + Storage	0.3%	1.4%	5.8%	0.4%
Solar + Wind	0.0%	0.0%	0.0%	0.0%
Steam - Coal	13.7%	25.5%	37.6%	6.4%
Steam - Natural Gas	90.5%	91.1%	91.1%	90.5%
Steam - Oil	0.0%	0.0%	0.0%	0.0%
Steam - Other	31.0%	40.6%	48.6%	27.4%
Wind	16.1%	32.8%	49.3%	7.4%
Wind + Storage	45.3%	45.3%	45.3%	30.0%

On March 31, 2025, 167,067.4 MW were in generation request queues in the status of active, under construction or suspended. Of the total 167,067.4 MW in the queue, 60,815.4 MW (36.4 percent) have reached at least the SIS milestone and 106,252.1 MW (63.6 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), 33,489.2 MW (20.0 percent) of new generation in the queue are expected to go into service.

Table 12-30 shows the percent of all project MW, by unit type, to go in service by year submitted to the queue. Of all battery projects that entered the queue in 2010, 65.5 percent reached the status of in service by March 31, 2025. Of all battery projects that entered the queue in 2016, only 1.3 percent have reached the status of in service as of March 31, 2025.

Table 12-30 Percent of all projects (MW energy) to go in service by unit type and year submitted to the queue: March 31, 2025

Unit Type	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Battery	65.5%	8.3%	15.1%	45.7%	21.5%	11.5%	1.3%	0.0%	3.1%	0.4%	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%
CC	14.6%	24.5%	30.8%	35.6%	53.6%	13.4%	20.7%	8.1%	4.1%	2.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
CT - Natural Gas	100.0%	98.3%	71.6%	42.2%	56.8%	0.2%	13.2%	38.9%	8.5%	5.4%	7.2%	0.0%	0.0%	NA	0.0%	0.0%
CT - Oil	100.0%	NA	1.2%	0.0%	0.0%	NA	NA	NA	0.0%	100.0%	100.0%	NA	NA	NA	0.0%	0.0%
CT - Other	28.8%	26.2%	36.1%	100.0%	0.0%	100.0%	NA	0.0%	NA	NA	NA	0.0%	NA	NA	0.0%	0.0%
Fuel Cell	NA	NA	NA	NA	NA	67.4%	0.0%	0.0%	NA	100.0%	NA	0.0%	NA	NA	0.0%	0.0%
Hydro - Pumped Storage	NA	NA	NA	NA	NA	100.0%	NA	NA	0.0%	0.0%	NA	0.0%	NA	NA	0.0%	0.0%
Hydro - Run of River	0.0%	0.0%	57.6%	49.6%	11.2%	NA	100.0%	26.8%	100.0%	0.0%	0.0%	0.0%	NA	NA	0.0%	0.0%
Nuclear	15.5%	1.6%	0.0%	100.0%	NA	NA	25.4%	100.0%	100.0%	NA	0.0%	NA	NA	NA	0.0%	0.0%
RICE - Natural Gas	NA	NA	100.0%	66.7%	5.4%	6.2%	0.0%	5.4%	NA	100.0%	NA	0.0%	NA	NA	0.0%	0.0%
RICE - Oil	0.0%	0.0%	NA	NA	NA	30.8%	NA	NA	NA	NA	NA	NA	0.0%	NA	0.0%	0.0%
RICE - Other	100.0%	100.0%	100.0%	100.0%	79.7%	25.5%	2.8%	0.0%	100.0%	NA	NA	NA	NA	NA	0.0%	0.0%
Solar	10.7%	8.1%	16.9%	24.4%	30.5%	29.3%	37.1%	13.2%	6.5%	8.0%	0.6%	0.0%	0.0%	0.0%	0.0%	0.0%
Solar + Storage	NA	NA	NA	NA	NA	100.0%	0.7%	0.0%	0.0%	0.0%	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%
Solar + Wind	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	0.0%	0.0%	NA	NA	0.0%	0.0%
Steam - Coal	100.0%	0.0%	1.4%	68.4%	1.2%	23.4%	37.5%	100.0%	22.4%	0.0%	NA	NA	NA	NA	0.0%	0.0%
Steam - Natural Gas	NA	NA	NA	100.0%	0.0%	100.0%	100.0%	100.0%	NA	NA	45.5%	NA	NA	NA	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%
Steam - Other	0.5%	61.2%	16.6%	0.0%	0.0%	NA	NA	NA	NA	NA	NA	0.0%	0.0%	NA	0.0%	0.0%
WInd	6.1%	3.4%	2.5%	20.9%	20.7%	12.5%	21.0%	2.6%	1.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Wind + Storage	NA	NA	NA	NA	NA	NA	0.0%	0.0%	NA	NA	NA	NA	0.0%	NA	0.0%	0.0%
All	11.6%	19.0%	25.9%	35.9%	42.3%	15.7%	25.8%	10.7%	3.9%	4.4%	0.5%	0.0%	0.0%	0.0%	0.0%	0.0%

Table 12-31 shows the total MW that went in service each year, by unit type, since 1999. In the first three months of 2025, 994.8 MW from the queue went in service. Of the 994.8 MW that went in service, 994.8 MW (100.0 percent) were solar units.

Table 12-31 Total (MW Energy) by unit type and year project went in service: March 31, 2025

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	2023	2024	2025
Battery	4.0	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	40.0	25.5	0.0	1.5	0.0	61.8	42.5	0.0
CC	0.0	0.0	100.0	2,608.0	2,785.0	2,845.0	15.1	1,196.0	4.0	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	2,983.0	88.0	3,424.7	1,825.9	2,644.0	0.0	0.0
CT - Natural Gas	0.0	409.6	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	156.0	314.0	153.5	532.1	0.0	0.0
CT - Oil	4.0	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	13.0	0.0	0.0	0.0	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	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	1.5	0.0	3.0	0.0	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	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	0.0	0.0	0.0
Nuclear	54.2	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	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	14.4	0.0	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	0.0	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	39.8	2.0	109.0	0.0	3.8	19.3	22.4	0.0	0.8	0.0	0.0	0.0	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	290.8	332.9	285.7	555.6	1,670.8	807.5	1,078.5	1,232.0	4,451.0	994.8
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	1.0	0.0	1.0	2.0	1.1	0.0	0.0	0.0	17.0	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	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	720.5	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	0.0	0.0	0.0
Steam - Natural Gas	5.0	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	0.0	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	0.0	0.0	0.0
Steam - Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	529.0	18.0	20.0	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	0.0	0.0	0.0
WInd	0.0	0.0	0.0	15.0	190.0	20.4	7.5	380.0	867.3	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	282.4	289.8	0.0
Wind + Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	186.0	0.0	0.0	0.0	0.0	0.0	0.0	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	79.2	430.8	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	3,826.6	3,194.2	742.7	3,001.4	4,371.8	7,133.0	5,385.5	12,412.9	4,268.0	3,009.8	4,883.1	3,057.9	4,769.3	4,783.3	994.8

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 12-32 shows the number of projects that entered the queue by year and by fuel group. The fuel groups are nuclear units, renewable units (including hydro run of river, solar and wind units (including renewable solar and wind hybrids), storage units (including battery and pumped storage hydro units), thermal units (including combined cycle, CT natural gas and oil, RICE natural gas and oil and steam coal, natural gas and oil) and other units (all other fuels). The number of queue entries has increased during the past several years, primarily by renewable projects. Of the 5,538 projects entered from January 2015 through March 2025, 4,111 projects (74.2 percent) were renewable.

Table 12-32 Number of projects entered in the queue: March 31, 2025

	Fuel Group										
Year Entered	Nuclear	Percent Nuclear	Renewable	Percent Renewable	Storage	Percent Storage	Thermal	Percent Thermal	Other	Percent Other	Total
1997	2	15.38%	0	0.00%	0	0.00%	11	84.62%	0	0.00%	13
1998	0	0.00%	0	0.00%	0	0.00%	18	100.00%	0	0.00%	18
1999	1	1.11%	5	5.56%	0	0.00%	82	91.11%	2	2.22%	90
2000	2	2.41%	3	3.61%	0	0.00%	75	90.36%	3	3.61%	83
2001	4	4.40%	6	6.59%	0	0.00%	78	85.71%	3	3.30%	91
2002	3	5.88%	15	29.41%	0	0.00%	23	45.10%	10	19.61%	51
2003	1	1.89%	34	64.15%	0	0.00%	13	24.53%	5	9.43%	53
2004	4	7.41%	17	31.48%	0	0.00%	23	42.59%	10	18.52%	54
2005	3	2.26%	74	55.64%	1	0.75%	36	27.07%	19	14.29%	133
2006	9	5.73%	67	42.68%	0	0.00%	47	29.94%	34	21.66%	157
2007	9	4.11%	64	29.22%	1	0.46%	123	56.16%	22	10.05%	219
2008	3	1.39%	102	47.22%	7	3.24%	79	36.57%	25	11.57%	216
2009	10	5.78%	107	61.85%	2	1.16%	34	19.65%	20	11.56%	173
2010	5	1.13%	370	83.90%	5	1.13%	40	9.07%	21	4.76%	441
2011	6	1.69%	264	74.37%	4	1.13%	61	17.18%	20	5.63%	355
2012	2	1.26%	59	37.11%	11	6.92%	69	43.40%	18	11.32%	159
2013	1	0.65%	54	35.06%	21	13.64%	69	44.81%	9	5.84%	154
2014	0	0.00%	100	52.08%	21	10.94%	59	30.73%	12	6.25%	192
2015	0	0.00%	130	42.07%	63	20.39%	103	33.33%	13	4.21%	309
2016	2	0.50%	284	71.18%	22	5.51%	65	16.29%	26	6.52%	399
2017	2	0.56%	280	78.87%	7	1.97%	47	13.24%	19	5.35%	355
2018	1	0.23%	341	77.50%	50	11.36%	47	10.68%	1	0.23%	440
2019	0	0.00%	546	78.34%	100	14.35%	50	7.17%	1	0.14%	697
2020	2	0.20%	780	78.23%	193	19.36%	21	2.11%	1	0.10%	997
2021	0	0.00%	966	72.36%	348	26.07%	10	0.75%	11	0.82%	1,335
2022	0	0.00%	370	68.65%	160	29.68%	8	1.48%	1	0.19%	539
2023	0	0.00%	414	88.65%	42	8.99%	11	2.36%	0	0.00%	467
2024	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0
2025	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0
Total	72	0.88%	5,452	66.57%	1,058	12.92%	1,302	15.90%	306	3.74%	8,190

As of March 31, 2025, renewable projects make up 77.5 percent of all projects in the queue and those projects account for 72.0 percent of the nameplate MW currently active, suspended or under construction in the queue as of March 31, 2025 (Table 12-33).

Table 12-33 Queue details by fuel group: March 31, 2025

Fuel Group	Number of Projects	Percent of Projects	MW	Percent MW
Nuclear	1	0.0%	44.0	0.0%
Renewable	1,575	77.5%	120,350.5	72.0%
Storage	405	19.9%	37,000.4	22.1%
Thermal	43	2.1%	9,619.5	5.8%
Other	7	0.3%	53.0	0.0%
Total	2,031	100.0%	167,067.4	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.

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.[74] 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 are determined by PJM's effective load carrying capability (ELCC) analysis. The PJM ELCC analysis will determine capacity derates by resource class for each Delivery Year. The unforced capacity derate for a specific resource will equal the product of the ELCC class rating and a resource specific performance factor. For example, the 2026/2027 Base Residual Auction ELCC class rating for onshore wind resources is 41.0 percent, for solar resources with tracking panels is 11.0 percent and for solar resources with fixed panels is 8.0 percent.[75] 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 50.0 percent for storage resources that can continuously generate energy at the nameplate capacity for four hours (four hour storage). The ELCC class rating is 58.0 percent for six hour storage and 62.0 percent for 8 hour storage and 72.0 percent for 10 hour storage.[76]

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 12-29). Table 12-34 shows the total MW of all projects in the queue as of March 31, 2025, in the status of active, suspended and under construction, by unit type. Table 12-34 also shows the total MW Energy and MW Capacity for each fuel type adjusted based on current historical completion rates and, for Capacity MW in the queue, adjusted for ELCC derates.[77] [78]

Table 12-34 shows that of the 7,664.8 MW, on an energy basis, of combined cycle projects in the queue, 4,194.3 MW (54.7 percent) are expected to go in service based on historical completion rates as of March 31, 2025.

Of the 37,000.4 MW, on an energy basis, of battery projects in the queue, 1,294.3 MW (3.5 percent) are expected to go in service based on historical completion rates as of March 31, 2025.

74 See "PJM Manual 14B: PJM Region Transmission Planning Process," Rev. 57 (September 25, 2024).

75 *ELCC Class Ratings for 2026/2027 Base Residual Auction*, PJM Interconnection L.L.C. (February 28, 2025) <https://www.pjm.com/-/media/DotCom/planning/res-adeq/elcc/2026-27-bra-elcc-class-ratings.pdf>

76 Additional information available in *PJM Manual 21A: Determination of Accredited UCAP Using Effective Load Carrying Capability Analysis*, PJM Interconnection L.L.C., Rev. 5 (June 27, 2024).

77 The 2026/2027 Base Residual Auction ELCC factors are used for the ELCC derate adjusted MW. The adjusted MW are calculated using the four hour storage ELCC derate of 50.0 percent for battery resources, 41.0 percent ELCC derate for wind resources and 11.0 percent ELCC derate for solar resources.

78 *ELCC Class Ratings for 2026/2027 Base Residual Auction*, PJM Interconnection L.L.C. (February 28, 2025) <https://www.pjm.com/-/media/DotCom/planning/res-adeq/elcc/2026-27-bra-elcc-class-ratings.pdf>.

Of the 120,350.5 MW, on an energy basis, of renewable projects in the queue, 26,775.4 MW (22.3 percent) are expected to go in service based on historical completion rates as of March 31, 2025.

Of the 7,463.1 MW, on a capacity basis that requested CIRs, of combined cycle projects requested in the generation queues in the status of active, under construction or suspended, 3,978.1 MW (53.3 percent) are expected to go into service based on historical completion rates. Based on historical completion rates and the ELCC derate factors using the class ratings for the 2026/2027 Base Residual Auction,[79] the 7,463.1 MW of capacity requests currently under construction, suspended or active in the queue would be reduced to 2,943.8 MW of capacity (39.4 percent of the total requested capacity).[80]

Of the 32,993.3 MW, on a capacity basis that requested CIRs, of battery projects requested in the generation queues in the status of active, under construction or suspended, 194.7 MW (0.6 percent) are expected to go into service based on historical completion rates. Based on historical completion rates and the ELCC derate factors using the class ratings for the 2026/2027 Base Residual Auction,[81] the 32,993.3 MW of capacity requests currently under construction, suspended or active in the queue would be reduced to 97.3 MW of capacity (0.3 percent of the total requested capacity).[82]

Of the 65,103.4 MW, on a capacity basis that requested CIRs, of renewable projects requested in the generation queues in the status of active, under construction or suspended, 13,240.3 MW (20.3 percent) are expected to go into service based on historical completion rates. Based on historical completion rates and the ELCC derate factors using the class ratings for the 2026/2027 Base Residual Auction, the 65,103.4 MW of capacity requests currently under construction, suspended or active in the queue would be reduced to 1,844.2 MW of capacity (2.8 percent of the total requested capacity).[83]

As of March 31, 2025, 107,595.6 MW of capacity requests (requested CIRs) were in the generation queues in the status of active, under construction or suspended. Based on historical completion rates, 18,598.3 MW (17.3 percent) are expected to go into service. Based on historical completion rates and the ELCC derate factors using the class ratings for the 2026/2027 Base Residual Auction, the 107,595.6 MW of capacity requests currently under construction, suspended or active in the queue would be reduced to 5,610.6 MW of capacity (5.2 percent of the total requested capacity).

Table 12-34 Queue totals for projects (active, suspended and under construction) by unit type adjusted for current historical completion rates and ELCC derates (MW): March 31, 2025[84]

	Energy (MW)		Capacity (MW)		
Unit Type	Total	Completion Rate Adjusted	Total	Completion Rate Adjusted	Completion Rate and ELCC Adjusted
Battery	37,000.4	1,294.3	32,993.3	194.7	97.3
CC	7,664.8	4,194.3	7,463.1	3,978.1	2,943.8
CT - Natural Gas	1,889.7	1,168.9	1,875.5	1,130.6	678.4
CT - Oil	0.0	0.0	0.0	0.0	0.0
CT - Other	28.0	2.3	27.3	2.3	1.4
Fuel Cell	5.0	1.4	5.0	0.5	0.4
Hydro - Pumped Storage	0.0	0.0	0.0	0.0	0.0
Hydro - Run of River	87.1	45.0	62.8	30.5	11.6
Nuclear	44.0	22.6	44.0	22.1	21.0
RICE - Natural Gas	0.0	0.0	0.0	0.0	0.0
RICE - Oil	0.0	0.0	0.0	0.0	0.0
RICE - Other	0.0	0.0	0.0	0.0	0.0
Solar	75,698.7	20,975.0	42,415.7	11,808.3	1,298.9
Solar + Storage	19,159.2	183.1	15,325.7	136.3	15.0
Solar + Wind	0.0	0.0	0.0	0.0	0.0
Steam - Coal	65.0	24.4	65.0	24.5	20.3
Steam - Natural Gas	0.0	0.0	0.0	0.0	0.0
Steam - Oil	0.0	0.0	0.0	0.0	0.0
Steam - Other	20.1	5.5	19.1	5.1	3.7
Wind	25,255.5	5,527.2	7,272.9	1,253.4	513.9
Wind + Storage	150.0	45.0	26.4	11.8	4.8
Total	167,067.4	33,489.2	107,595.6	18,598.3	5,610.6

79 *ELCC Class Ratings for 2026/2027 Base Residual Auction*, PJM Interconnection L.L.C. (February 28, 2025) <https://www.pjm.com/-/media/DotCom/planning/res-adeq/elcc/2026-27-bra-elcc-class-ratings.pdf>.

80 The 2026/2027 Base Residual Auction ELCC factors are used for the ELCC derate adjusted MW. The adjusted MW are calculated using the four hour storage ELCC derate for battery resources, tracking solar for solar resources and onshore wind for wind resources.

81 *ELCC Class Ratings for 2026/2027 Base Residual Auction*, PJM Interconnection L.L.C. (February 28, 2025) <https://www.pjm.com/-/media/DotCom/planning/res-adeq/elcc/2026-27-bra-elcc-class-ratings.pdf>.

82 The 2026/2027 Base Residual Auction ELCC factors are used for the ELCC derate adjusted MW. The adjusted MW are calculated using the four hour storage ELCC derate for battery resources, tracking solar for solar resources and onshore wind for wind resources.

83 The 2026/2027 Base Residual Auction ELCC factors are used for the ELCC derate adjusted MW. The adjusted MW are calculated using the four hour storage ELCC derate for battery resources, tracking solar for solar resources and onshore wind for wind resources.

84 The 2026/2027 Base Residual Auction ELCC factors are used for the ELCC derate adjusted MW. The adjusted MW are calculated using the four hour storage ELCC derate for battery resources, tracking solar for solar resources and onshore wind for wind resources.

Queue Analysis by Unit Type and Project Classification

Table 12-35 shows the current status of all generation queue projects by unit type and project classification from January 1, 1997, through March 31, 2025. As of March 31, 2025, 8,190 projects, representing 824,096.3 MW, have entered the queue process since its inception. Of those, 1,244 projects, representing 93,129.4 MW (11.3 percent of the MW), went into service. Of the projects that entered the queue process, 4,915 projects, representing 563,899.4 MW (68.4 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 6,169 projects have been classified as new generation and 2,021 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 6,437 projects (78.6 percent) of all 8,190 generation queue projects to enter the queue since January 1, 1997.

Table 12-35 Status of all generation queue projects: January 1, 1997 through March 31, 2025

		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	32	67	50	10	25	2	0	10	2	11	0	55	292	6	0	8	6	0	4	100	1	681
	Upgrade	8	118	137	25	5	1	3	19	45	9	2	16	81	0	0	57	10	0	8	18	1	563
Under Construction	New Generation	2	3	0	0	0	0	0	0	0	0	0	0	43	5	0	0	0	0	0	6	0	59
	Upgrade	0	2	1	0	0	0	0	0	1	0	0	0	16	2	0	3	0	0	0	1	0	26
Suspended	New Generation	9	2	0	0	0	0	0	0	0	0	0	0	91	1	0	0	0	0	0	5	0	108
	Upgrade	4	0	0	0	0	0	0	0	0	0	0	0	15	0	0	0	0	0	0	0	0	19
Withdrawn	New Generation	399	439	32	10	85	28	4	47	9	30	12	16	2,215	276	2	55	1	0	35	514	1	4,210
	Upgrade	206	111	26	13	13	1	1	5	15	0	3	3	221	27	0	15	2	0	2	40	1	705
Active	New Generation	240	5	2	0	3	0	0	3	0	0	0	0	622	189	0	0	0	0	2	44	1	1,111
	Upgrade	150	11	14	0	0	1	0	1	0	0	0	0	417	24	1	0	0	0	1	88	0	708
Total Projects	New Generation	682	516	84	20	113	30	4	60	11	41	12	71	3,263	477	2	63	7	0	41	669	3	6,169
	Upgrade	368	242	178	38	18	3	4	25	61	9	5	19	750	53	1	75	12	0	11	147	2	2,021

Table 12-36 shows the totals in Table 12-35 by share of classification as new generation or upgrade. Within a unit type the shares of upgrades add to 100 percent and the shares of new generation add to 100 percent. For example, 76.0 percent of all hydro run of river projects classified as upgrades are currently in service in PJM, 20.0 percent of hydro run of river upgrades were withdrawn and 4.0 percent of hydro run of river upgrades are active in the queue.

Table 12-36 Status of all generation queue projects as a percent of total projects by classification: January 1, 1997 through March 31, 2025

		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	4.7%	13.0%	59.5%	50.0%	22.1%	6.7%	0.0%	16.7%	18.2%	26.8%	0.0%	77.5%	8.9%	1.3%	0.0%	12.7%	85.7%	0.0%	9.8%	14.9%	33.3%	11.0%
	Upgrade	2.2%	48.8%	77.0%	65.8%	27.8%	33.3%	75.0%	76.0%	73.8%	100.0%	40.0%	84.2%	10.8%	0.0%	0.0%	76.0%	83.3%	0.0%	72.7%	12.2%	50.0%	27.9%
Under Construction	New Generation	0.3%	0.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.3%	1.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.9%	0.0%	1.0%
	Upgrade	0.0%	0.8%	0.6%	0.0%	0.0%	0.0%	0.0%	0.0%	1.6%	0.0%	0.0%	0.0%	2.1%	3.8%	0.0%	4.0%	0.0%	0.0%	0.0%	0.7%	0.0%	1.3%
Suspended	New Generation	1.3%	0.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	2.8%	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.7%	0.0%	1.8%
	Upgrade	1.1%	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%	0.0%	0.0%	0.0%	0.9%
Withdrawn	New Generation	58.5%	85.1%	38.1%	50.0%	75.2%	93.3%	100.0%	78.3%	81.8%	73.2%	100.0%	22.5%	67.9%	57.9%	100.0%	87.3%	14.3%	0.0%	85.4%	76.8%	33.3%	68.2%
	Upgrade	56.0%	45.9%	14.6%	34.2%	72.2%	33.3%	25.0%	20.0%	24.6%	0.0%	60.0%	15.8%	29.5%	50.9%	0.0%	20.0%	16.7%	0.0%	18.2%	27.2%	50.0%	34.9%
Active	New Generation	35.2%	1.0%	2.4%	0.0%	2.7%	0.0%	0.0%	5.0%	0.0%	0.0%	0.0%	0.0%	19.1%	39.6%	0.0%	0.0%	0.0%	0.0%	4.9%	6.6%	33.3%	18.0%
	Upgrade	40.8%	4.5%	7.9%	0.0%	0.0%	33.3%	0.0%	4.0%	0.0%	0.0%	0.0%	0.0%	55.6%	45.3%	100.0%	0.0%	0.0%	0.0%	9.1%	59.9%	0.0%	35.0%

Table 12-37 shows the total MW of projects in the PJM generation queue by unit type and project classification. For example, the 514 new generation wind projects that have been withdrawn from the queue as of March 31, 2025, (as shown in Table 12-35) constitute 107,211.0 MW. The 439 new generation combined cycle projects that have been withdrawn in the same time period constitute 221,312.8 MW.

Table 12-37 Status of all generation (MW) in the generation queue: January 1, 1997 through March 31, 2025

		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	324.2	39,701.9	6,734.4	676.5	149.2	1.5	0.0	371.5	1,639.0	170.8	0.0	440.1	10,864.6	22.1	0.0	1,343.0	728.0	0.0	60.9	10,901.8	186.0	74,315.5
	Upgrade	52.4	8,600.1	3,192.1	144.8	12.3	3.0	390.0	387.6	2,365.0	17.3	27.3	47.5	1,362.6	0.0	0.0	979.0	225.5	0.0	683.3	324.1	0.0	18,813.9
Under Construction	New Generation	21.0	2,090.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3,001.1	211.6	0.0	0.0	0.0	0.0	0.0	1,443.0	0.0	6,766.7
	Upgrade	0.0	153.8	60.0	0.0	0.0	0.0	0.0	0.0	44.0	0.0	0.0	0.0	409.5	103.2	0.0	65.0	0.0	0.0	0.0	105.9	0.0	941.4
Suspended	New Generation	500.7	1,845.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6,737.5	17.5	0.0	0.0	0.0	0.0	0.0	1,606.7	0.0	10,707.4
	Upgrade	142.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	370.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	512.2
Withdrawn	New Generation	25,170.9	221,312.8	5,794.3	1,735.0	1,593.1	6.4	1,200.0	2,089.1	8,161.0	495.6	63.9	88.6	95,783.3	21,717.2	209.0	33,511.6	27.0	0.0	1,070.9	107,211.0	90.0	527,330.6
	Upgrade	5,553.2	13,852.9	1,461.5	589.0	68.7	0.0	30.0	107.2	1,066.0	0.0	19.6	10.0	6,879.3	1,117.1	0.0	885.0	6.0	0.0	37.1	4,869.9	16.3	36,568.8
Active	New Generation	29,331.4	3,309.0	1,269.0	0.0	28.0	0.0	0.0	36.1	0.0	0.0	0.0	0.0	56,665.0	18,329.7	0.0	0.0	0.0	0.0	20.1	21,016.2	150.0	130,154.3
	Upgrade	7,005.1	267.0	560.7	0.0	0.0	5.0	0.0	51.0	0.0	0.0	0.0	0.0	8,515.7	497.3	0.0	0.0	0.0	0.0	0.0	1,083.8	0.0	17,985.5
Total Projects	New Generation	55,348.2	268,258.7	13,797.7	2,411.5	1,770.3	7.9	1,200.0	2,496.6	9,800.0	666.4	63.9	528.7	173,051.4	40,298.1	209.0	34,854.6	755.0	0.0	1,151.8	142,178.6	426.0	749,274.5
	Upgrade	12,752.9	22,873.8	5,274.3	733.8	81.0	8.0	420.0	545.8	3,475.0	17.3	46.9	57.5	17,537.1	1,717.6	0.0	1,929.0	231.5	0.0	720.4	6,383.7	16.3	74,821.8

Table 12-38 shows the MW totals in Table 12-37 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, 75.4 percent of wind project MW classified as new generation have been withdrawn from the queue between January 1, 1997, and March 31, 2025.

Table 12-38 Status of all generation queue projects as percent of total MW in project classification: January 1, 1997 through March 31, 2025

		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	0.6%	14.8%	48.8%	28.1%	8.4%	19.2%	0.0%	14.9%	16.7%	25.6%	0.0%	83.2%	6.3%	0.1%	0.0%	3.9%	96.4%	0.0%	5.3%	7.7%	43.7%	9.9%
	Upgrade	0.4%	37.6%	60.5%	19.7%	15.2%	37.5%	92.9%	71.0%	68.1%	100.0%	58.2%	82.6%	7.8%	0.0%	0.0%	50.8%	97.4%	0.0%	94.9%	5.1%	0.0%	25.1%
Under Construction	New Generation	0.0%	0.8%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.7%	0.5%	0.0%	0.0%	0.0%	0.0%	0.0%	1.0%	0.0%	0.9%
	Upgrade	0.0%	0.7%	1.1%	0.0%	0.0%	0.0%	0.0%	0.0%	1.3%	0.0%	0.0%	0.0%	2.3%	6.0%	0.0%	3.4%	0.0%	0.0%	0.0%	1.7%	0.0%	1.3%
Suspended	New Generation	0.9%	0.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	3.9%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.1%	0.0%	1.4%
	Upgrade	1.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	2.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.7%
Withdrawn	New Generation	45.5%	82.5%	42.0%	71.9%	90.0%	80.8%	100.0%	83.7%	83.3%	74.4%	100.0%	16.8%	55.3%	53.9%	100.0%	96.1%	3.6%	0.0%	93.0%	75.4%	21.1%	70.4%
	Upgrade	43.5%	60.6%	27.7%	80.3%	84.8%	0.0%	7.1%	19.6%	30.7%	0.0%	41.8%	17.4%	39.2%	65.0%	0.0%	45.9%	2.6%	0.0%	5.1%	76.3%	100.0%	48.9%
Active	New Generation	53.0%	1.2%	9.2%	0.0%	1.6%	0.0%	0.0%	1.4%	0.0%	0.0%	0.0%	0.0%	32.7%	45.5%	0.0%	0.0%	0.0%	0.0%	1.7%	14.8%	35.2%	17.4%
	Upgrade	54.9%	1.2%	10.6%	0.0%	0.0%	62.5%	0.0%	9.3%	0.0%	0.0%	0.0%	0.0%	48.6%	29.0%	0.0%	0.0%	0.0%	0.0%	0.0%	17.0%	0.0%	24.0%

Table 12-39 shows the project MW that entered the PJM generation queue by unit type and year of entry. Since 2016, 71.2 percent of all new projects entering the generation queue have been combined cycle (10.1 percent), wind (17.7 percent) or solar projects (43.4 percent). Prior to 2015, no renewable hybrid units (solar + storage, solar + wind and wind + storage) entered the queue. In the time period from January 1, 2015 through March 31, 2025, 42,666.9 MW of renewable hybrid units have entered the queue.

Table 12-39 Queue project MW by unit type and queue entry year: January 1, 1997 through March 31, 2025

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	2,069.1	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	32,420.2
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	1,428.7	186.0	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	13,926.6	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	68.5	18,510.5	0.0	43,685.5
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	1,200.5	0.0	0.0	189.8	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	54.6	3,672.6	0.0	0.0	64.0	0.0	0.0	173.5	9,803.4	0.0	23,888.1
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	1,585.6	0.0	0.0	1,730.5	27.0	0.0	43.1	1,691.3	0.0	19,096.3
2015	546.9	27,550.8	1,324.5	0.0	0.9	2.3	34.0	0.0	0.0	320.4	13.0	31.4	2,919.3	3.4	0.0	47.0	606.5	0.0	0.0	2,160.6	0.0	35,560.9
2016	111.1	18,802.5	1,392.0	0.0	0.0	2.9	0.0	12.5	59.0	23.5	0.0	38.9	11,538.9	85.6	0.0	80.0	77.0	0.0	0.0	3,445.7	16.3	35,685.9
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	13,686.8	324.9	0.0	14.0	17.0	0.0	0.0	5,137.0	90.0	25,660.3
2018	1,413.7	11,080.1	2,512.4	14.0	0.0	0.0	700.0	2.4	28.1	0.0	0.0	0.8	20,121.0	3,957.9	0.0	49.0	0.0	0.0	0.0	17,683.3	0.0	57,562.7
2019	5,244.5	3,901.5	1,003.7	13.0	0.0	3.0	500.0	99.0	0.0	14.4	0.0	0.0	30,275.1	6,902.0	0.0	11.0	0.0	0.0	0.0	11,233.2	0.0	59,200.3
2020	11,629.1	50.0	846.6	4.0	0.0	0.0	0.0	80.2	100.0	0.0	0.0	0.0	38,433.1	7,934.6	199.0	0.0	11.0	0.0	0.0	6,578.2	0.0	65,865.9
2021	25,767.3	2,129.0	752.0	0.0	373.1	5.0	30.0	22.5	0.0	14.4	0.0	0.0	49,062.2	11,274.2	10.0	0.0	0.0	0.0	30.1	11,160.0	0.0	100,629.7
2022	17,528.0	192.0	20.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6.6	0.0	14,992.8	9,846.5	0.0	0.0	0.0	0.0	10.0	14,214.3	150.0	56,960.2
2023	4,977.4	70.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,064.6	1,686.5	0.0	0.0	0.0	0.0	0.0	3,580.9	0.0	11,379.3
2024	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2025	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	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	68,101.1	291,132.5	19,072.0	3,145.3	1,851.3	15.9	1,620.0	3,042.4	13,275.0	683.7	110.8	586.2	190,588.5	42,015.6	209.0	36,783.6	986.5	0.0	1,872.2	148,562.3	442.3	824,096.3

Combined Cycle Project Analysis

Table 12-40 shows the status of all combined cycle projects by number of projects that entered PJM generation queues from January 1, 1997, through March 31, 2025, by zone. Of the 23 combined cycle projects classified as new generation or upgrade currently active, suspended or under construction in the PJM generation queue, six projects (26.1 percent) are located in the DOM Zone and six projects (26.1 percent) are located in the APS Zone.

Table 12-40 Status of all combined cycle queue projects by zone (number of projects): January 1, 1997 through March 31, 2025

		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	7	0	3	4	2	3	0	2	0	7	2	0	7	4	0	5	2	4	9	5	0	67
	Upgrade	3	16	0	10	5	0	6	0	0	0	16	5	0	6	5	0	13	3	4	12	14	0	118
Under Construction	New Generation	0	2	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3
	Upgrade	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	2
Suspended	New Generation	0	0	0	1	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2
	Upgrade	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Withdrawn	New Generation	24	20	0	46	14	8	16	1	1	2	18	16	3	26	25	0	44	41	35	42	55	2	439
	Upgrade	7	9	0	11	4	0	5	0	1	0	13	6	0	8	7	0	4	7	6	8	15	0	111
Active	New Generation	0	0	0	4	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	5
	Upgrade	0	0	0	1	2	0	0	0	0	0	5	0	0	0	0	0	0	1	1	0	1	0	11
Total Projects	New Generation	25	29	0	54	19	10	20	1	3	2	26	18	3	33	29	0	49	43	39	51	60	2	516
	Upgrade	10	25	0	22	11	0	12	0	1	0	34	11	0	14	12	0	17	11	11	20	31	0	242

Table 12-41 shows the status of all combined cycle projects by MW that entered PJM generation queues from January 1, 1997, through March 31, 2025, by zone. Of the 7,664.8 MW of combined cycle projects classified as new generation or upgrade currently active, suspended or under construction in the PJM generation queue, 4,055.0 MW (52.9 percent) are located in the APS Zone.

Table 12-41 Status of all combined cycle queue projects by zone (MW): January 1, 1997 through March 31, 2025

		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	5,611.0	0.0	1,970.0	3,751.0	140.0	2,960.9	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	5,892.0	1,698.5	0.0	39,701.9
	Upgrade	229.0	1,300.0	0.0	959.7	344.0	0.0	642.6	0.0	0.0	0.0	1,035.0	102.0	0.0	110.0	188.9	0.0	1,075.5	112.3	228.6	1,426.6	845.9	0.0	8,600.1
Under Construction	New Generation	0.0	1,150.0	0.0	0.0	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	2,090.0
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	102.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	51.1	0.0	153.8
Suspended	New Generation	0.0	0.0	0.0	1,270.0	0.0	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	1,845.0
	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	8,542.5	13,559.5	0.0	22,373.1	9,596.0	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	221,312.8
	Upgrade	156.9	1,031.0	0.0	1,368.0	636.0	0.0	1,735.0	0.0	36.0	0.0	804.4	1,410.0	0.0	413.0	1,742.0	0.0	245.0	1,125.6	229.1	703.0	2,217.9	0.0	13,852.9
Active	New Generation	0.0	0.0	0.0	2,740.0	0.0	0.0	0.0	0.0	0.0	0.0	569.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3,309.0
	Upgrade	0.0	0.0	0.0	45.0	128.0	0.0	0.0	0.0	0.0	0.0	19.0	0.0	0.0	0.0	0.0	0.0	0.0	30.0	45.0	0.0	0.0	0.0	267.0
Total Projects	New Generation	9,192.5	20,320.5	0.0	28,353.1	14,287.0	3,262.1	14,352.9	1,150.0	667.5	665.0	19,358.6	5,464.6	991.8	15,228.4	15,558.0	0.0	26,805.0	18,014.0	23,828.2	24,809.7	25,943.1	6.9	268,258.7
	Upgrade	385.9	2,331.0	0.0	2,372.7	1,108.0	0.0	2,480.3	0.0	36.0	0.0	1,858.4	1,512.0	0.0	523.0	1,930.9	0.0	1,320.5	1,267.9	502.7	2,129.6	3,114.9	0.0	22,873.8

Of the 23 combined cycle units in the queue as of March 31, 2025, in the status of active, under construction or suspended, eight units, representing 756.0 MW had a projected in service date prior to January 1, 2025 and 15 units, representing 6,908.8 MW had a projected in service date between January 1, 2025, and December 31, 2028.

Combustion Turbine - Natural Gas Project Analysis

Table 12-42 shows the status of all combustion turbine natural gas projects by number of projects that entered PJM generation queues from January 1, 1997, through March 31, 2025, by zone. Of the 17 combustion turbine natural gas projects classified as new generation or upgrade currently active, suspended or under construction in the PJM generation queue, eight projects (47.1 percent) are located in the DOM Zone.

Table 12-42 Status of all combustion turbine - natural gas generation queue projects by zone (number of projects): January 1, 1997 through March 31, 2025

		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	1	0	0	1	3	6	0	2	1	0	2	5	2	4	9	0	50
	Upgrade	4	11	0	10	5	0	20	6	0	0	28	8	0	5	5	0	4	8	5	4	14	0	137
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
	Upgrade	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Suspended	New Generation	0	0	0	0	0	0	0	0	0	0	0	0	0	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	2	6	0	0	0	2	1	1	0	0	4	0	1	1	0	0	1	6	0	1	6	0	32
	Upgrade	4	1	0	1	1	0	5	3	0	2	3	0	0	0	1	0	0	2	3	0	0	0	26
Active	New Generation	0	1	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	2
	Upgrade	0	2	0	1	4	0	0	0	0	0	7	0	0	0	0	0	0	0	0	0	0	0	14
Total Projects	New Generation	7	7	0	6	0	5	2	1	0	1	8	6	1	3	1	0	3	11	2	5	15	0	84
	Upgrade	8	14	0	12	10	0	26	9	0	2	38	8	0	5	6	0	4	10	8	4	14	0	178

Table 12-43 shows the status of all combustion turbine natural gas projects by MW that entered PJM generation queues from January 1, 1997, through March 31, 2025, by zone. Of the 1,889.7 MW of combustion turbine natural gas projects classified as new generation or upgrade currently active, suspended or under construction in the PJM generation queue, 772.0 MW (40.9 percent) are located in the AEP Zone.

Table 12-43 Status of all combustion turbine - natural gas queue projects by zone (MW): January 1, 1997 through March 31, 2025

		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	1,184.0	0.0	23.0	190.0	0.0	0.0	205.0	1,081.0	1,140.0	0.0	520.0	10.0	0.0	559.0	379.9	5.0	150.9	925.9	0.0	6,734.4
	Upgrade	43.7	278.1	0.0	269.7	105.0	0.0	744.0	83.5	0.0	0.0	925.7	86.0	0.0	20.0	47.6	0.0	42.0	40.5	39.0	252.3	215.0	0.0	3,192.1
Under Construction	New Generation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	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	60.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	60.0
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	237.5	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	789.8	0.0	19.9	1,815.1	0.0	5,794.3
	Upgrade	165.5	6.0	0.0	4.0	25.0	0.0	686.2	124.0	0.0	18.5	57.0	0.0	0.0	0.0	0.0	0.0	0.0	327.0	48.3	0.0	0.0	0.0	1,461.5
Active	New Generation	0.0	700.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	569.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,269.0
	Upgrade	0.0	72.0	0.0	30.0	458.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	560.7
Total Projects	New Generation	598.2	2,219.0	0.0	1,184.0	0.0	176.6	200.0	104.0	0.0	205.0	2,719.8	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	13,797.7
	Upgrade	209.2	356.1	0.0	303.7	588.7	0.0	1,490.2	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	5,274.3

Of the 17 combustion turbine natural gas units in the queue as of March 31, 2025, in the status of active, under construction or suspended, nine units, representing 72.0 MW had a projected in service date prior to January 1, 2025 and eight units, representing 1,817.7 MW had a projected in service date between January 1, 2025, and December 31, 2031.

Wind Project Analysis

Table 12-44 shows the status of all wind generation projects, by number of projects that entered PJM generation queues from January 1, 1997, through March 31, 2025, by zone. Of the 144 wind projects classified as new generation or upgrade currently active, suspended or under construction in the PJM generation queue, 54 projects (37.5 percent) are located in the COMED Zone.

Table 12-44 Status of all wind generation queue projects by zone (number of projects): January 1, 1997 through March 31, 2025

		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	17	0	0	28	0	0	0	4	0	0	0	0	0	0	23	0	8	0	0	100
	Upgrade	0	0	0	3	0	0	9	0	0	0	0	0	0	0	0	0	0	6	0	0	0	0	18
Under Construction	New Generation	0	0	0	1	0	0	3	0	0	0	1	0	0	0	0	0	0	1	0	0	0	0	6
	Upgrade	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Suspended	New Generation	1	0	0	1	0	0	2	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	5
	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	122	0	46	10	0	126	16	0	0	23	20	1	11	0	0	0	64	0	50	2	0	514
	Upgrade	2	2	0	7	0	0	10	0	0	0	3	3	0	4	0	0	0	7	0	2	0	0	40
Active	New Generation	0	10	0	5	1	0	14	0	0	0	4	2	0	6	0	0	0	1	0	0	1	0	44
	Upgrade	2	23	0	10	1	0	34	0	0	0	2	2	0	5	0	0	0	9	0	0	0	0	88
Total Projects	New Generation	25	151	0	70	11	0	173	16	0	0	32	22	1	18	0	0	0	89	0	58	3	0	669
	Upgrade	4	25	0	20	1	0	54	0	0	0	5	5	0	9	0	0	0	22	0	2	0	0	147

Table 12-45 shows the status of all wind projects by MW that entered PJM generation queues from January 1, 1997, through March 31, 2025, by zone. Of the 25,255.5 MW of wind projects classified as new generation or upgrade currently active, suspended or under construction in the PJM generation queue, 10,616.9 MW (42.0 percent) are located in the JCPLC Zone.

Table 12-45 Status of all wind generation queue projects by zone (MW): January 1, 1997 through March 31, 2025

		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	1,178.0	0.0	0.0	4,386.7	0.0	0.0	0.0	511.5	0.0	0.0	0.0	0.0	0.0	0.0	1,047.0	0.0	226.5	0.0	0.0	10,901.8
	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	105.9	0.0	0.0	0.0	0.0	324.1
Under Construction	New Generation	0.0	0.0	0.0	54.9	0.0	0.0	1,200.0	0.0	0.0	0.0	78.2	0.0	0.0	0.0	0.0	0.0	0.0	109.9	0.0	0.0	0.0	0.0	1,443.0
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	105.9	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	105.9
Suspended	New Generation	432.0	0.0	0.0	80.0	0.0	0.0	278.7	0.0	0.0	0.0	0.0	0.0	0.0	816.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,606.7
	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	7,653.2	25,331.4	0.0	3,552.2	1,814.0	0.0	29,632.7	2,228.0	0.0	0.0	6,588.6	8,958.4	150.3	10,840.2	0.0	0.0	0.0	5,307.0	0.0	3,835.2	1,320.0	0.0	107,211.0
	Upgrade	5.0	370.0	0.0	119.4	0.0	0.0	772.2	0.0	0.0	0.0	114.0	910.0	0.0	2,330.0	0.0	0.0	0.0	243.4	0.0	6.0	0.0	0.0	4,869.9
Active	New Generation	0.0	1,728.6	0.0	671.5	297.7	0.0	3,144.9	0.0	0.0	0.0	3,289.1	696.6	0.0	9,800.9	0.0	0.0	0.0	77.0	0.0	0.0	1,310.0	0.0	21,016.2
	Upgrade	0.0	212.6	0.0	207.6	0.0	0.0	338.4	0.0	0.0	0.0	0.0	75.3	0.0	0.0	0.0	0.0	0.0	249.8	0.0	0.0	0.0	0.0	1,083.8
Total Projects	New Generation	8,092.7	30,604.6	0.0	5,536.6	2,111.7	0.0	38,642.9	2,228.0	0.0	0.0	10,467.4	9,655.0	150.3	21,457.1	0.0	0.0	0.0	6,540.8	0.0	4,061.7	2,630.0	0.0	142,178.6
	Upgrade	5.0	582.6	0.0	332.0	0.0	0.0	1,429.7	0.0	0.0	0.0	114.0	985.3	0.0	2,330.0	0.0	0.0	0.0	599.1	0.0	6.0	0.0	0.0	6,383.7

Of the 144 wind units in the queue as of March 31, 2025, in the status of active, under construction or suspended, 66 units, representing 3,333.3 MW had a projected in service date prior to January 1, 2025 and 78 units, representing 21,922.2 MW had a projected in service date between January 1, 2025, and December 31, 2031.

A total of 83 offshore winds projects entered PJM generation queues from January 1, 1997, through March 31, 2025. Offshore wind projects are included in the wind generation statistics. Of the 144 wind projects classified as new generation or upgrade currently active, suspended or under construction in the PJM generation queue (Table 12-44), 24 projects (16.7 percent) are offshore wind. Of the 25,255.5 MW of wind projects classified as new generation or upgrade currently active, suspended or under construction in the PJM generation queue (Table 12-45), 16,419.9 MW (65.0 percent) are offshore wind projects. Table 12-44 shows that 554 wind projects have been withdrawn from the queue. Of those 554 wind projects, 58 projects (10.5 percent) were offshore wind. Table 12-45 shows that those 554 wind projects that have been withdrawn from the queue totaled 112,080.9 MW. Of the 112,080.9 MW of withdrawn wind projects, 29,567.9 MW (26.4 percent) were offshore wind projects.

Solar Project Analysis

Table 12-46 shows the status of all solar generation projects by number of projects that entered PJM generation queues from January 1, 1997, through March 31, 2025, by zone. Of the 1,024 solar projects classified as new generation or upgrade currently active, suspended or under construction in the PJM generation queue, 328 projects (27.2 percent) are located in the AEP Zone.

Table 12-46 Status of all solar generation queue projects by zone (number of projects): January 1, 1997 through March 31, 2025

		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	11	22	0	22	3	1	2	6	3	3	77	18	2	55	5	0	1	7	3	5	46	0	292
	Upgrade	2	9	0	6	2	0	1	3	3	1	22	12	1	12	0	0	0	1	0	3	3	0	81
Under Construction	New Generation	3	12	0	3	3	2	0	1	0	0	4	5	2	2	0	0	0	4	0	1	1	0	43
	Upgrade	0	0	0	0	0	0	0	1	0	0	10	2	1	1	0	0	0	0	0	0	1	0	16
Suspended	New Generation	1	22	1	6	5	0	3	2	1	0	19	2	0	1	3	0	0	13	2	10	0	0	91
	Upgrade	0	6	0	0	0	0	0	1	0	0	3	3	0	0	0	0	0	2	0	0	0	0	15
Withdrawn	New Generation	201	244	0	189	75	16	78	42	22	2	416	172	51	207	66	2	18	158	29	103	124	0	2,215
	Upgrade	4	43	1	17	16	0	12	8	1	0	45	5	4	9	7	3	0	21	3	19	3	0	221
Active	New Generation	9	143	0	48	37	1	50	10	1	3	132	24	38	21	2	2	3	73	2	22	1	0	622
	Upgrade	5	145	0	21	24	0	35	14	1	1	56	20	15	8	10	0	0	32	0	28	2	0	417
Total Projects	New Generation	225	443	1	268	123	20	133	61	27	8	648	221	93	286	76	4	22	255	36	141	172	0	3,263
	Upgrade	11	203	1	44	42	0	48	27	5	2	136	42	21	30	17	3	0	56	3	50	9	0	750

Table 12-47 shows the status of all solar projects by MW that entered PJM generation queues from January 1, 1997, through March 31, 2025, by zone. Of the 75,698.7 MW of solar projects classified as new generation or upgrade currently active, suspended or under construction in the PJM generation queue, 28,502.5 MW (37.7 percent) are located in the AEP Zone.

Table 12-47 Status of all solar generation queue projects by zone (MW): January 1, 1997 through March 31, 2025

		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	67.6	2,692.0	0.0	697.1	423.0	1.1	59.0	649.3	214.9	45.9	4,411.8	296.5	85.0	417.1	160.0	0.0	3.3	288.6	35.6	75.0	241.9	0.0	10,864.6
	Upgrade	0.0	557.0	0.0	60.0	60.0	0.0	50.0	144.8	85.0	8.3	312.8	39.8	20.0	13.1	0.0	0.0	0.0	0.0	0.0	10.0	1.8	0.0	1,362.6
Under Construction	New Generation	13.6	1,310.8	0.0	206.8	275.0	30.0	0.0	49.9	0.0	0.0	334.0	330.9	150.0	35.2	0.0	0.0	0.0	178.9	0.0	80.0	6.0	0.0	3,001.1
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	339.9	40.0	20.0	7.6	0.0	0.0	0.0	0.0	0.0	0.0	2.0	0.0	409.5
Suspended	New Generation	49.7	2,351.1	40.0	199.5	567.9	0.0	140.0	227.9	100.0	0.0	2,086.0	93.0	0.0	10.0	195.0	0.0	0.0	359.4	40.0	278.0	0.0	0.0	6,737.5
	Upgrade	0.0	183.0	0.0	0.0	0.0	0.0	0.0	20.0	0.0	0.0	85.0	52.0	0.0	0.0	0.0	0.0	0.0	30.0	0.0	0.0	0.0	0.0	370.0
Withdrawn	New Generation	2,296.6	21,941.7	0.0	5,515.7	4,136.3	131.5	7,932.4	3,487.0	1,099.4	33.0	30,252.8	3,282.0	4,636.1	1,735.5	1,335.5	198.0	193.8	4,312.9	470.1	2,182.6	610.3	0.0	95,783.3
	Upgrade	172.5	2,351.2	65.0	280.4	662.7	0.0	248.0	192.0	20.0	0.0	1,787.6	0.0	94.0	23.8	158.0	90.0	0.0	405.0	3.6	324.2	1.3	0.0	6,879.3
Active	New Generation	373.0	21,778.0	0.0	2,748.7	2,334.9	55.0	7,705.6	1,016.6	49.0	34.7	11,318.5	856.2	3,236.7	531.8	99.6	398.5	49.8	3,050.0	135.0	885.5	8.0	0.0	56,665.0
	Upgrade	15.0	2,879.6	0.0	209.2	276.0	0.0	2,354.1	245.1	0.0	0.0	1,631.0	164.5	289.8	11.0	20.0	0.0	0.0	264.5	0.0	155.9	0.0	0.0	8,515.7
Total Projects	New Generation	2,800.5	50,073.6	40.0	9,367.8	7,737.0	217.6	15,837.0	5,430.6	1,463.3	113.6	48,403.1	4,858.6	8,107.8	2,729.6	1,790.1	596.5	246.9	8,189.9	680.6	3,501.1	866.2	0.0	173,051.4
	Upgrade	187.5	5,970.8	65.0	549.6	998.7	0.0	2,652.1	601.9	105.0	8.3	4,156.3	296.3	423.8	55.5	178.0	90.0	0.0	699.5	3.6	490.1	5.1	0.0	17,537.1

Of the 1,204 solar units in the queue as of March 31, 2025, in the status of active, under construction or suspended, 545 units, representing 30,922.8 MW had a projected in service date prior to January 1, 2025 and 659 units, representing 44,775.9 MW had a projected in service date between January 1, 2025, and December 31, 2031.

Battery Project Analysis

Table 12-48 shows the status of all battery generation projects by number of projects that entered PJM generation queues from January 1, 1997, through March 31, 2025, by zone. Of the 405 battery projects currently active, suspended or under construction in the PJM generation queue, 122 projects (30.1 percent) are located in the DOM Zone.

Table 12-48 Status of all battery generation queue projects by zone (number of projects): January 1, 1997 through March 31, 2025

		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	3	0	3	0	2	7	1	4	0	1	0	0	7	0	0	1	0	0	1	2	0	32
	Upgrade	0	1	0	0	0	0	0	1	1	0	0	0	0	3	0	0	0	2	0	0	0	0	8
Under Construction	New Generation	0	0	0	0	0	0	0	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	2
	Upgrade	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Suspended	New Generation	0	2	0	0	0	0	0	0	0	0	2	0	0	0	0	0	0	1	0	2	2	0	9
	Upgrade	0	1	0	0	0	0	1	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0	4
Withdrawn	New Generation	12	57	0	11	16	28	38	4	5	4	105	27	2	43	6	0	4	9	4	13	11	0	399
	Upgrade	8	38	0	20	6	1	19	3	1	0	65	5	3	7	6	0	3	16	0	5	0	0	206
Active	New Generation	13	50	0	14	3	6	30	1	1	2	84	5	3	10	3	0	0	5	5	0	5	0	240
	Upgrade	2	26	1	9	8	1	40	3	0	0	35	6	1	5	3	0	0	8	0	1	1	0	150
Total Projects	New Generation	25	112	0	28	19	36	75	6	10	6	192	33	5	61	9	0	5	15	9	16	20	0	682
	Upgrade	10	66	1	29	14	2	60	7	3	0	101	11	4	15	9	0	3	26	0	6	1	0	368

Table 12-49 shows the status of all battery projects by MW that entered PJM generation queues from January 1, 1997, through March 31, 2025, by zone. Of the 37,000.4 MW of battery generation currently active, suspended or under construction in the PJM generation queue, 8,726.1 MW (23.6 percent) are located in the DOM Zone.

Table 12-49 Status of all battery generation queue projects by zone (MW): January 1, 1997 through March 31, 2025

		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	10.0	0.0	39.9	0.0	3.5	86.0	12.0	16.0	0.0	20.0	0.0	0.0	112.8	0.0	0.0	1.0	0.0	0.0	20.0	3.0	0.0	324.2
	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	8.0	0.0	0.0	0.0	28.4	0.0	0.0	0.0	0.0	52.4
Under Construction	New Generation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.0	0.0	20.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	21.0
	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	100.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	55.7	0.0	0.0	0.0	0.0	0.0	0.0	160.0	0.0	170.0	15.0	0.0	500.7
	Upgrade	0.0	40.0	0.0	0.0	0.0	0.0	10.0	0.0	52.2	0.0	40.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	142.2
Withdrawn	New Generation	519.0	4,079.4	0.0	834.2	1,566.1	705.6	3,197.8	419.9	300.5	475.0	8,584.7	814.0	70.3	1,036.1	395.9	0.0	4.3	705.8	321.0	529.8	611.5	0.0	25,170.9
	Upgrade	20.0	1,787.2	0.0	717.3	40.3	115.0	755.3	137.0	20.0	0.0	1,322.0	74.0	28.0	55.1	189.0	0.0	60.0	193.0	0.0	40.0	0.0	0.0	5,553.2
Active	New Generation	1,617.3	5,934.7	0.0	1,525.6	350.0	895.0	5,149.4	85.0	250.0	50.0	7,920.4	429.0	98.0	1,230.0	330.0	0.0	0.0	470.0	2,117.0	0.0	880.0	0.0	29,331.4
	Upgrade	0.0	1,165.8	0.0	847.3	488.0	300.0	2,621.0	163.0	0.0	0.0	710.0	110.0	0.0	90.0	285.0	0.0	0.0	210.0	0.0	0.0	15.0	0.0	7,005.1
Total Projects	New Generation	2,136.3	10,124.1	0.0	2,399.7	1,916.1	1,604.1	8,433.2	516.9	566.5	525.0	16,580.8	1,244.0	168.3	2,398.9	725.9	0.0	5.3	1,335.8	2,438.0	719.8	1,509.5	0.0	55,348.2
	Upgrade	20.0	2,997.0	0.0	1,564.6	528.3	415.0	3,386.3	308.0	76.2	0.0	2,072.0	184.0	28.0	153.1	474.0	0.0	60.0	431.4	0.0	40.0	15.0	0.0	12,752.9

Of the 405 battery units in the queue as of March 31, 2025, in the status of active, under construction or suspended, 158 units, representing 10,789.1 MW had a projected in service date prior to January 1, 2025 and 247 units, representing 26,211.3 MW had a projected in service date between January 1, 2025, and December 31, 2030.

Renewable Hybrid Project Analysis

Table 12-50 shows the status of all renewable hybrid generation projects (solar + storage, solar + wind and wind + storage) by number of projects that entered PJM generation queues from January 1, 1997, through March 31, 2025, by zone.[85] Of the 223 renewable hybrid projects currently active, suspended or under construction in the PJM generation queue, 66 projects (29.6 percent) are located in the AEP Zone.

Table 12-50 Status of all renewable hybrid generation queue projects by zone (number of projects): January 1, 1997 through March 31, 2025

		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	1	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	5	0	7
	Upgrade	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Under Construction	New Generation	0	1	0	0	3	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	5
	Upgrade	0	2	0	0	0	0	0	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	1	0	0	0	0	0	0	0	0	0	0	0	0	1
	Upgrade	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Withdrawn	New Generation	7	42	0	27	9	0	11	6	2	1	76	4	15	4	9	0	1	18	2	34	11	0	279
	Upgrade	2	3	0	4	2	0	1	2	0	0	5	0	1	0	1	0	0	1	0	6	0	0	28
Active	New Generation	2	61	0	13	4	1	12	6	1	1	28	6	14	3	16	0	0	13	1	8	0	0	190
	Upgrade	0	2	0	4	1	0	2	1	0	0	5	0	1	0	0	0	0	6	0	3	0	0	25
Total Projects	New Generation	9	104	0	41	16	1	23	12	3	3	105	11	29	7	25	0	1	31	3	42	16	0	482
	Upgrade	2	7	0	8	3	0	4	3	0	0	10	0	2	0	1	0	0	7	0	9	0	0	56

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

Table 12-51 shows the status of all renewable hybrid projects by MW that entered PJM generation queues from January 1, 1997, through March 31, 2025, by zone. Of the 19,309.2 MW of renewable hybrid generation currently active, suspended or under construction in the PJM generation queue, 7,509.4 MW (38.9 percent) are located in the AEP Zone.

Table 12-51 Status of all renewable hybrid generation queue projects by zone (MW): January 1, 1997 through March 31, 2025

		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	186.0	0.0	0.0	0.0	0.0	0.0	0.0	17.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.1	0.0	208.1
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Under Construction	New Generation	0.0	150.0	0.0	0.0	57.7	0.0	0.0	0.0	0.0	0.0	0.0	3.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	211.6
	Upgrade	0.0	103.2	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	103.2
Suspended	New Generation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	17.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	17.5
	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	77.5	7,405.7	0.0	1,088.9	859.9	0.0	1,388.8	258.9	50.0	20.0	7,168.2	264.5	1,629.0	95.0	40.9	0.0	5.0	920.9	120.0	567.0	56.1	0.0	22,016.2
	Upgrade	93.0	440.0	0.0	218.7	30.0	0.0	20.0	40.0	0.0	0.0	60.0	0.0	35.0	0.0	3.7	0.0	0.0	38.2	0.0	154.8	0.0	0.0	1,133.4
Active	New Generation	83.0	7,211.2	0.0	1,986.0	228.8	50.0	1,586.6	351.9	800.0	70.0	2,567.4	203.4	998.1	140.0	201.3	0.0	0.0	1,101.8	670.2	230.0	0.0	0.0	18,479.7
	Upgrade	0.0	45.0	0.0	0.0	30.1	0.0	0.0	0.0	0.0	0.0	139.0	0.0	30.0	0.0	0.0	0.0	0.0	117.0	0.0	136.2	0.0	0.0	497.3
Total Projects	New Generation	160.5	14,766.9	0.0	3,260.9	1,146.4	50.0	2,975.4	610.8	850.0	107.5	9,752.6	471.8	2,627.1	235.0	242.2	0.0	5.0	2,022.7	790.2	797.0	61.1	0.0	40,933.1
	Upgrade	93.0	588.2	0.0	218.7	60.1	0.0	20.0	40.0	0.0	0.0	199.0	0.0	65.0	0.0	3.7	0.0	0.0	155.2	0.0	291.0	0.0	0.0	1,733.9

Of the 223 renewable hybrid units in the queue as of March 31, 2025, in the status of active, under construction or suspended, 89 units, representing 6,039.2 MW had a projected in service date prior to January 1, 2025 and 134 units, representing 13,270.0 MW had a projected in service date between January 1, 2025, and December 31, 2031.

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."[86] 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 12-52 shows the relationship between the project developer and transmission owner for all project MW that have entered the PJM generation queue from January 1, 1997, through March 31, 2025, by transmission owner and unit type. A project where the developer is affiliated with the transmission owner is classified as related. A project where the developer is not affiliated with the transmission owner is classified as unrelated. For example, 36.0 MW of combined cycle generation projects that have entered the PJM generation queue in the DUKE Zone were projects developed by Duke Energy or subsidiaries of Duke Energy, the transmission owner for the DUKE Zone. These project MW are classified as related. There have been 667.5 MW of combined cycle projects that have entered the PJM generation queue in the DUKE Zone by developers not affiliated with Duke Energy. These project MW are classified as unrelated.

86 See OATT § 1 (Transmission Owner).

Of the 824,096.3 MW that have entered the queue during the time period of January 1, 1997, through March 31, 2025, 67,145.1 MW (8.1 percent) have been submitted by transmission owners building in their own service territory. PSEG is the transmission owner with the highest percentage of affiliates building in their own service territory. Of the 39,266.7 MW that entered the queue in the PSEG Zone during the time period of January 1, 1997, through March 31, 2025, 13,480.8 MW (34.3 percent) were submitted by PSEG or one of their affiliated companies.

Table 12-52 Relationship between project developer and transmission owner for all interconnection queue projects MW by unit type: March 31, 2025

				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	50	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	0.0	0.0	3,918.0	90.0	0.0	0.0	0.0	0.0	5,352.1	3.4%
		Unrelated	1,260	13,005.1	21,973.5	2,575.1	7.5	486.7	0.0	0.0	453.6	0.0	12.0	0.0	75.4	55,744.7	15,355.1	0.0	10,399.0	0.0	0.0	462.0	31,187.2	0.0	151,736.8	96.6%
AES	DAY	Related	15	40.0	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	1,456.0	11.6%
		Unrelated	137	784.9	1,150.0	264.5	0.0	12.0	0.0	0.0	0.0	0.0	0.0	0.0	10.0	6,011.0	650.8	0.0	0.0	0.0	0.0	0.0	2,228.0	0.0	11,111.2	88.4%
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	105.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	105.0	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	49	525.0	665.0	223.5	40.0	19.2	0.0	0.0	194.6	1,879.0	14.4	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	207	896.7	11,397.5	1,476.7	100.0	0.0	0.0	340.0	0.0	1,944.0	0.0	0.0	60.0	5,199.2	17.0	0.0	301.0	0.0	0.0	4.0	946.1	0.0	22,682.2	18.9%
		Unrelated	1,201	17,756.1	9,819.5	2,225.8	0.5	227.3	0.0	0.0	35.0	0.0	0.0	10.0	116.2	47,360.3	9,784.6	0.0	20.0	0.0	0.0	334.3	9,635.3	150.0	97,474.9	81.1%
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	4.5%
		Unrelated	45	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	840.0	10.0	120.0	0.0	0.0	0.0	0.0	0.0	3,822.6	95.5%
EKPC	EKPC	Related	3	0.0	821.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	40.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	861.8	6.8%
		Unrelated	156	196.3	170.0	73.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8,491.6	2,692.1	0.0	0.0	0.0	0.0	0.0	150.3	0.0	11,773.2	93.2%
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	391	2,156.3	9,048.4	807.4	388.0	20.7	2.8	0.0	0.0	0.0	2.0	5.0	10.3	2,979.7	253.5	0.0	15.0	5.5	0.0	10.0	8,097.7	0.0	23,802.3	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	5.7%
		Unrelated	78	1,996.6	3,012.1	166.6	18.0	133.0	0.0	0.0	0.4	3,280.0	1.3	0.0	0.0	197.6	50.0	0.0	0.0	2.5	0.0	25.0	0.0	0.0	8,883.1	94.3%
	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	667	11,819.5	16,833.2	1,394.2	42.0	65.2	5.0	0.0	22.7	0.0	35.0	0.0	67.7	18,480.1	2,796.4	199.0	1,926.0	91.0	0.0	90.0	40,072.6	0.0	93,939.6	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	0.2%
		Unrelated	426	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	5,147.6	471.8	0.0	653.0	15.0	0.0	75.0	10,640.3	0.0	27,298.3	99.8%
	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	120	2,437.0	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	790.2	0.0	0.0	6.0	0.0	0.0	0.0	0.0	29,552.2	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	675	3,964.3	29,272.8	1,487.7	0.0	84.4	0.0	0.0	637.3	0.0	154.4	53.8	25.4	9,846.2	3,277.3	0.0	4,092.0	0.0	0.0	184.4	5,868.6	202.3	59,150.9	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	5.5%
		Unrelated	283	2,444.4	13,717.0	588.7	10.5	166.4	0.0	0.0	0.0	0.0	59.7	6.6	6.9	8,735.7	1,206.5	0.0	0.0	16.5	0.0	0.0	2,111.7	0.0	29,070.5	94.5%
	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	490	2,552.0	15,751.4	542.1	0.0	4.8	0.2	30.0	1.6	0.0	0.6	0.0	12.8	2,773.1	235.0	0.0	0.0	0.0	0.0	30.0	23,787.1	0.0	45,720.6	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	220	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	1,968.1	245.9	0.0	0.0	0.0	0.0	84.0	0.0	0.0	22,425.1	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	5.3%
		Unrelated	628	1,767.2	18,747.9	1,532.2	0.0	218.0	3.0	16.0	46.3	0.0	341.8	8.0	14.8	8,889.4	2,177.9	0.0	561.0	590.0	0.0	525.0	7,139.9	0.0	42,578.1	94.7%
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	7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	686.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	686.5	100.0%
PPL	PPL	Related	25	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	146.8	0.0	0.0	111.0	0.0	0.0	0.0	0.0	0.0	4,277.8	8.9%
		Unrelated	454	759.8	24,678.3	423.1	8.0	234.5	0.0	1,200.0	142.6	438.0	19.9	2.4	44.7	3,844.5	998.0	0.0	6,899.1	0.0	0.0	28.5	4,067.7	90.0	43,879.1	91.1%
PSEG	PSEG	Related	105	0.0	11,035.0	1,818.1	0.0	0.0	0.0	0.0	0.0	381.0	0.0	0.0	0.0	174.0	4.7	0.0	24.0	44.0	0.0	0.0	0.0	0.0	13,480.8	34.3%
		Unrelated	282	1,524.5	18,023.0	1,137.9	600.0	62.5	4.9	0.0	1,000.0	0.0	10.6	0.0	13.7	697.3	56.5	0.0	0.0	25.0	0.0	0.0	2,630.0	0.0	25,785.9	65.7%
Con Ed	REC	Related	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	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	518	1,154.5	38,752.3	3,657.8	183.0	4.0	0.0	374.0	396.4	5,945.0	0.0	0.0	68.5	6,114.3	21.7	0.0	9,288.5	235.0	0.0	4.0	946.1	0.0	67,145.1	8.1%
		Unrelated	7,672	66,946.7	252,380.2	15,414.2	2,962.3	1,847.3	15.9	1,246.0	2,646.0	7,330.0	683.7	110.8	517.7	184,474.2	41,993.9	209.0	27,495.1	751.5	0.0	1,868.2	147,616.2	442.3	756,951.2	91.9%

Combined Cycle Project Developer and Transmission Owner Relationships

Table 12-53 shows the relationship between the project developer and transmission owner for all combined cycle project MW that have entered the PJM generation queue from January 1, 1997, through March 31, 2025, by transmission owner and project status. Of the 50,545.8 combined cycle project MW that are in service or currently under construction, 8,648.5 MW (17.1 percent) have been developed by transmission owners building in their own service territory. EKPC is the transmission owner with the highest percentage of affiliates building combined cycle projects in their own service territory. Of the 991.8 MW that entered the queue in the EKPC Zone during the time period of January 1, 1997, through March 31, 2025, 821.8 MW (82.9 percent) have been submitted by EKPC or one of their affiliated companies.

Table 12-53 Relationship between project developer and transmission owner for all combined cycle project MW in the queue: March 31, 2025

			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	0.0	6,233.0	1,150.0	0.0	14,590.5	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	19.0	4,837.5	0.0	0.0	6,541.0	11,397.5	53.7%
		Unrelated	569.0	2,026.1	0.0	0.0	7,224.4	9,819.5	46.3%
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	5.5%
		Unrelated	0.0	879.0	0.0	0.0	8,169.4	9,048.4	94.5%
	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	0.0	3,603.5	102.7	575.0	12,552.0	16,833.2	100.0%
	DPL	Related	0.0	60.0	0.0	0.0	0.0	60.0	0.9%
		Unrelated	0.0	361.2	0.0	0.0	6,555.4	6,916.6	99.1%
	PECO	Related	0.0	0.0	0.0	0.0	7,515.0	7,515.0	26.7%
		Unrelated	0.0	3,740.5	0.0	0.0	16,870.0	20,610.5	73.3%
	PEPCO	Related	0.0	80.0	0.0	0.0	423.0	503.0	2.1%
		Unrelated	45.0	1,708.6	0.0	0.0	22,074.3	23,827.9	97.9%
First Energy	APS	Related	0.0	525.0	0.0	0.0	928.0	1,453.0	4.7%
		Unrelated	2,785.0	2,404.7	0.0	1,270.0	22,813.1	29,272.8	95.3%
	ATSI	Related	0.0	0.0	0.0	0.0	1,678.0	1,678.0	10.9%
		Unrelated	128.0	4,095.0	940.0	0.0	8,554.0	13,717.0	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	13,975.6	15,751.4	100.0%
	MEC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	0.0	2,745.9	0.0	0.0	14,743.0	17,488.9	100.0%
	PE	Related	0.0	0.0	0.0	0.0	534.0	534.0	2.8%
		Unrelated	30.0	2,012.3	0.0	0.0	16,705.6	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	8.4%
		Unrelated	0.0	6,718.6	0.0	0.0	17,959.7	24,678.3	91.6%
PSEG	PSEG	Related	0.0	1,738.0	0.0	0.0	9,297.0	11,035.0	38.0%
		Unrelated	0.0	806.4	51.1	0.0	17,165.5	18,023.0	62.0%
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	6.9	6.9	100.0%
Total		Related	19.0	8,648.5	0.0	0.0	30,084.8	38,752.3	13.3%
		Unrelated	3,557.0	39,653.5	2,243.8	1,845.0	205,080.8	252,380.2	86.7%

Combustion Turbine – Natural Gas Project Developer and Transmission Owner Relationships

Table 12-54 shows the relationship between the project developer and transmission owner for all CT – natural gas project MW that have entered the PJM generation queue from January 1, 1997, through March 31, 2025, by transmission owner and project status. Of the 9,986.5 CT – natural gas project MW that are in service or currently under construction, 1,803.0 (18.1 percent) have been developed by Transmission Owners building in their own service territory. PSEG is the transmission owner with the highest percentage of affiliates building CT – natural gas projects in their own service territory. Of the 2,956.0 MW that entered the queue in the PSEG Zone during the time period of January 1, 1997, through March 31, 2025, 1,818.1 MW (61.5 percent) have been submitted by PSEG or one of their affiliated companies.

Table 12-54 Relationship between project developer and transmission owner for all CT – natural gas project MW in the queue: March 31, 2025

			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	772.0	278.1	0.0	0.0	1,525.0	2,575.1	100.0%
AES	DAY	Related	0.0	47.0	0.0	0.0	0.0	47.0	15.1%
		Unrelated	0.0	36.5	0.0	0.0	228.0	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	205.0	0.0	0.0	18.5	223.5	100.0%
DOM	DOM	Related	569.0	824.0	0.0	0.0	83.7	1,476.7	39.9%
		Unrelated	0.0	1,182.7	0.0	0.0	1,043.1	2,225.8	60.1%
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	0.0	403.0	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	0.0	0.0	0.0	0.0	296.0	296.0	17.5%
		Unrelated	0.0	934.0	60.0	0.0	400.2	1,394.2	82.5%
	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	0.0	44.0	0.0	0.0	48.3	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	1,453.7	0.0	0.0	4.0	1,487.7	100.0%
	ATSI	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	458.7	105.0	0.0	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	57.6	0.0	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	0.0	415.4	0.0	0.0	1,116.8	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	0.0	909.0	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	569.0	1,803.0	0.0	0.0	1,285.8	3,657.8	19.2%
		Unrelated	1,260.7	8,123.5	60.0	0.0	5,970.0	15,414.2	80.8%

Wind Project Developer and Transmission Owner Relationships

Table 12-55 shows the relationship between the project developer and transmission owner for all wind project MW that have entered the PJM generation queue from January 1, 1997, through March 31, 2025, by transmission owner and project status. Of the 12,774.8 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 10,581.4 MW that entered the queue in the DOM Zone during the time period of January 1, 1997, through March 31, 2025, 946.1 MW (8.9 percent) have been submitted by DOM or one of their affiliated companies.

Table 12-55 Relationship between project developer and transmission owner for all wind project MW in the queue: March 31, 2025

			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	1,941.2	3,544.6	0.0	0.0	25,701.4	31,187.2	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	2,228.0	2,228.0	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	800.1	12.0	0.0	0.0	134.0	946.1	8.9%
		Unrelated	2,489.0	499.5	78.2	0.0	6,568.6	9,635.3	91.1%
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	150.3	150.3	100.0%
Exelon	ACEC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	0.0	7.5	0.0	432.0	7,658.2	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	3,483.3	4,599.9	1,305.9	278.7	30,404.8	40,072.6	100.0%
	DPL	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	771.9	0.0	0.0	0.0	9,868.4	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	879.1	1,183.0	54.9	80.0	3,671.6	5,868.6	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	9,800.9	0.0	0.0	816.0	13,170.2	23,787.1	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	326.8	1,152.9	109.9	0.0	5,550.3	7,139.9	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	0.0	226.5	0.0	0.0	3,841.2	4,067.7	100.0%
PSEG	PSEG	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	1,310.0	0.0	0.0	0.0	1,320.0	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	800.1	12.0	0.0	0.0	134.0	946.1	0.6%
		Unrelated	21,299.8	11,213.9	1,548.9	1,606.7	111,946.9	147,616.2	99.4%

Solar Project Developer and Transmission Owner Relationships

Table 12-56 shows the relationship between the project developer and transmission owner for all solar project MW that have entered the PJM generation queue from January 1, 1997, through March 31, 2025, by transmission owner and project status. Of the 15,637.8 solar project MW that are in service or currently under construction, 2,163.2 MW (13.8 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 871.3 MW that entered the queue in the PSEG Zone during the time period of January 1, 1997, through March 31, 2025, 174.0 MW (20.0 percent) have been submitted by PSEG or one of their affiliated companies.

Table 12-56 Relationship between project developer and transmission owner for all solar project MW in the queue: March 31, 2025

			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	0.5%
		Unrelated	24,557.6	3,214.3	1,310.8	2,534.1	24,127.9	55,744.7	99.5%
AES	DAY	Related	0.0	0.0	0.0	0.0	21.5	21.5	0.4%
		Unrelated	1,261.7	794.1	49.9	247.9	3,657.5	6,011.0	99.6%
AMP	AMPT	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	0.0	0.0	0.0	40.0	65.0	105.0	100.0%
DUQ	DUQ	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	34.7	54.2	0.0	0.0	33.0	121.9	100.0%
DOM	DOM	Related	1,253.8	1,755.1	223.9	20.0	1,946.4	5,199.2	9.9%
		Unrelated	11,695.7	2,969.5	450.0	2,151.0	30,094.1	47,360.3	90.1%
DUKE	DUKE	Related	49.0	0.0	0.0	0.0	56.4	105.4	6.7%
		Unrelated	0.0	299.9	0.0	100.0	1,063.0	1,462.9	93.3%
EKPC	EKPC	Related	40.0	0.0	0.0	0.0	0.0	40.0	0.5%
		Unrelated	3,486.5	105.0	170.0	0.0	4,730.1	8,491.6	99.5%
Exelon	ACEC	Related	0.0	0.0	0.0	0.0	8.3	8.3	0.3%
		Unrelated	388.0	67.6	13.6	49.7	2,460.9	2,979.7	99.7%
	BGE	Related	0.0	0.0	0.0	0.0	20.0	20.0	9.2%
		Unrelated	55.0	1.1	30.0	0.0	111.5	197.6	90.8%
	COMED	Related	0.0	9.0	0.0	0.0	0.0	9.0	0.0%
		Unrelated	10,059.7	100.0	0.0	140.0	8,180.4	18,480.1	100.0%
	DPL	Related	0.0	7.4	0.0	0.0	0.0	7.4	0.1%
		Unrelated	1,020.7	328.9	370.9	145.0	3,282.0	5,147.6	99.9%
	PECO	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	49.8	3.3	0.0	0.0	193.8	246.9	100.0%
	PEPCO	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	135.0	35.6	0.0	40.0	473.7	684.2	100.0%
First Energy	APS	Related	52.4	0.0	0.0	0.0	18.8	71.2	0.7%
		Unrelated	2,905.5	757.1	206.8	199.5	5,777.3	9,846.2	99.3%
	ATSI	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	2,610.9	483.0	275.0	567.9	4,798.9	8,735.7	100.0%
	JCPLC	Related	0.0	0.0	0.0	0.0	12.0	12.0	0.4%
		Unrelated	542.8	430.2	42.8	10.0	1,747.3	2,773.1	99.6%
	MEC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	119.6	160.0	0.0	195.0	1,493.5	1,968.1	100.0%
	PE	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	3,314.5	288.6	178.9	389.4	4,717.9	8,889.4	100.0%
OVEC	OVEC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	398.5	0.0	0.0	0.0	288.0	686.5	100.0%
PPL	PPL	Related	0.0	0.0	0.0	0.0	146.8	146.8	3.7%
		Unrelated	1,041.4	85.0	80.0	278.0	2,360.0	3,844.5	96.3%
PSEG	PSEG	Related	0.0	131.1	2.0	0.0	40.9	174.0	20.0%
		Unrelated	8.0	112.6	6.0	0.0	570.7	697.3	80.0%
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	1,495.2	1,937.3	225.9	20.0	2,436.0	6,114.3	3.2%
		Unrelated	63,685.5	10,289.9	3,184.7	7,087.5	100,226.6	184,474.2	96.8%

Battery Project Developer and Transmission Owner Relationships

Table 12-57 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 March 31, 2025, by transmission owner and project status. Of the 397.6 battery project MW that are in service or currently under construction, 63.5 MW (16.0 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 March 31, 2025, 40.0 MW (61.3 percent) have been submitted by PECO or one of their affiliated companies.

Table 12-57 Relationship between project developer and transmission owner for all battery project MW in the queue: March 31, 2025

			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	7,000.5	8.0	0.0	140.0	5,856.6	13,005.1	99.1%
AES	DAY	Related	0.0	20.0	0.0	0.0	20.0	40.0	4.8%
		Unrelated	248.0	0.0	0.0	0.0	536.9	784.9	95.2%
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	50.0	0.0	0.0	0.0	475.0	525.0	100.0%
DOM	DOM	Related	750.0	20.0	0.0	95.7	31.0	896.7	4.8%
		Unrelated	7,880.4	0.0	0.0	0.0	9,875.7	17,756.1	95.2%
DUKE	DUKE	Related	0.0	14.0	0.0	0.0	23.3	37.3	5.8%
		Unrelated	250.0	6.0	0.0	52.2	297.2	605.4	94.2%
EKPC	EKPC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	98.0	0.0	0.0	0.0	98.3	196.3	100.0%
Exelon	ACEC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	1,617.3	0.0	0.0	0.0	539.0	2,156.3	100.0%
	BGE	Related	0.0	2.5	0.0	0.0	20.0	22.5	1.1%
		Unrelated	1,195.0	1.0	0.0	0.0	800.6	1,996.6	98.9%
	COMED	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	7,770.4	86.0	0.0	10.0	3,953.2	11,819.5	100.0%
	DPL	Related	0.0	0.0	1.0	0.0	0.0	1.0	0.1%
		Unrelated	539.0	0.0	0.0	0.0	888.0	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	0.0	0.0	0.0	0.0	1.0	1.0	0.0%
		Unrelated	2,117.0	0.0	0.0	0.0	320.0	2,437.0	100.0%
First Energy	APS	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	2,372.9	39.9	0.0	0.0	1,551.5	3,964.3	100.0%
	ATSI	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	838.0	0.0	0.0	0.0	1,606.4	2,444.4	100.0%
	JCPLC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	1,320.0	120.8	20.0	0.0	1,091.2	2,552.0	100.0%
	MEC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	615.0	0.0	0.0	0.0	584.9	1,199.9	100.0%
	PE	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	680.0	28.4	0.0	160.0	898.8	1,767.2	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	0.0	20.0	0.0	170.0	569.8	759.8	100.0%
PSEG	PSEG	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	895.0	3.0	0.0	15.0	611.5	1,524.5	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	850.0	62.5	1.0	95.7	145.3	1,154.5	1.7%
		Unrelated	35,486.5	314.1	20.0	547.2	30,578.9	66,946.7	98.3%

Renewable Hybrid Project Developer and Transmission Owner Relationships

Table 12-58 shows the relationship between the project developer and transmission owner for all renewable hybrid project MW that have entered the PJM generation queue from January 1, 1997, through March 31, 2025, by transmission owner and project status. Of the 522.8 renewable hybrid project MW that are in service or currently under construction, 21.7 MW (4.1 percent) have been developed by transmission owners building in their own service territory. PSEG is the transmission owner with the highest percentage of affiliates building hybrid projects in their own service territory. Of the 61.1 MW that entered the queue in the PSEG Zone during the time period of January 1, 1997, through March 31, 2025, 4.7 MW (7.7 percent) have been submitted by PSEG or one of their affiliated companies.

Table 12-58 Relationship between project developer and transmission owner for all hybrid project MW in the queue: March 31, 2025

			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	7,256.2	0.0	253.2	0.0	7,845.7	15,355.1	100.0%
AES	DAY	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	351.9	0.0	0.0	0.0	298.9	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	70.0	0.0	0.0	17.5	20.0	107.5	100.0%
DOM	DOM	Related	0.0	17.0	0.0	0.0	0.0	17.0	0.2%
		Unrelated	2,706.4	0.0	0.0	0.0	7,228.2	9,934.6	99.8%
DUKE	DUKE	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	800.0	0.0	0.0	0.0	50.0	850.0	100.0%
EKPC	EKPC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	1,028.1	0.0	0.0	0.0	1,664.0	2,692.1	100.0%
Exelon	ACEC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	83.0	0.0	0.0	0.0	170.5	253.5	100.0%
	BGE	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%
	COMED	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	1,586.6	0.0	0.0	0.0	1,408.8	2,995.4	100.0%
	DPL	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	203.4	0.0	3.9	0.0	264.5	471.8	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	5.0	5.0	100.0%
	PEPCO	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	670.2	0.0	0.0	0.0	120.0	790.2	100.0%
First Energy	APS	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	1,986.0	186.0	0.0	0.0	1,307.6	3,479.6	100.0%
	ATSI	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	258.9	0.0	57.7	0.0	889.9	1,206.5	100.0%
	JCPLC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	140.0	0.0	0.0	0.0	95.0	235.0	100.0%
	MEC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	201.3	0.0	0.0	0.0	44.6	245.9	100.0%
	PE	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	1,218.8	0.0	0.0	0.0	959.1	2,177.9	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	366.2	0.0	0.0	0.0	721.8	1,088.0	100.0%
PSEG	PSEG	Related	0.0	4.7	0.0	0.0	0.0	4.7	7.7%
		Unrelated	0.0	0.4	0.0	0.0	56.1	56.5	92.3%
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	0.0	0.0	0.0%
Total		Related	0.0	21.7	0.0	0.0	0.0	21.7	0.1%
		Unrelated	18,977.0	186.4	314.8	17.5	23,149.6	42,645.2	99.9%

Transition Cycle 1

On November 29, 2022, the Commission issued an order accepting PJM's tariff revisions to improve the queue process.[87] The new queue process includes modifications to implement a cluster/cycle based processing method to replace the first in/first out processing method.[88] 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 transition to the new queue process began on July 10, 2023.

Transition cycle 1 (TC1) is comprised of 312 proposed generation projects. Those projects make up 40,650.2 MW. On March 31, 2025, all projects in TC1 were either in the status of active or were withdrawn from the cycle. Table 12-59 shows each status by unit type. Of the 40,650.2 MW in TC1, 17,873.8 MW (44.0 percent) were active and 22,776.3 MW (56.0 percent) were withdrawn. Of the 17,873.8 MW in the status of active, 9,762.3 MW (54.6 percent) were solar projects, 4,377.3 MW (24.5 percent) were wind projects, and 2,254.2 MW (12.6 percent) were battery projects.

Table 12-59 Transition Cycle 1 project status (MW) by unit type: March 31, 2025

	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	2,254.2	569.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	9,762.3	911.0	0.0	0.0	0.0	0.0	0.0	4,377.3	0.0	17,873.8
Withdrawn	4,028.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	11,342.5	3,197.2	199.0	0.0	0.0	0.0	0.0	4,009.5	0.0	22,776.3
Total	6,282.4	569.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	21,104.8	4,108.2	199.0	0.0	0.0	0.0	0.0	8,386.8	0.0	40,650.2

On May 20, 2024, PJM completed the phase 1 system impact study for transition cycle 1. Developers had 30 days (until June 20, 2024) to decide whether to proceed with their new service requests into the next study phase of TC1 or to withdraw their projects. Continuing with phase 2 required developers to meet the decision point 1 requirements (including additional readiness deposits and proof of site control).[89]

On December 20, 2024, PJM completed the phase 2 system impact study for transition cycle 1. Developers had 30 days (until January 19, 2025) to decide whether to proceed with their new service requests into the next study phase of TC1 or to withdraw their projects. Continuing with phase 3 requires developers to meet the decision point 2 requirements, (including additional readiness deposits and proof of site control).[90]

Table 12-60 shows the status of all TC1 projects as they have progressed through the cycle process. Of the 312 projects included in TC1, 122 projects (39.1 percent of all projects) were withdrawn during phase 1 or decision point 1. Those 122 projects made up 15,971.8 MW (39.3 percent of all MW in TC1). Sixty projects (19.2 percent of all projects) were withdrawn during phase 2 or decision point 2. Those 60 projects made up 6,804.5 MW (16.7 percent of all MW in TC1).

Table 12-60 Transition Cycle 1 status: March 31, 2025

	Number of Projects	Percent of Projects	MW Energy	Percent of MW Energy
Transition Cycle 1 Approved Projects	312	100.0%	40,650.2	100.0%
Withdrawn During Phase 1 or Decision Point 1	122	39.1%	15,971.8	39.3%
Withdrawn During Phase 2 or Decision Point 2	60	19.2%	6,804.5	16.7%
Active As of March 31, 2025	128	41.0%	17,353.8	42.7%
In Final Agreement Stage as of March 31, 2025	2	0.6%	520.0	1.3%

87 181 FERC ¶ 61,162 (2022).
88 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>.
89 See "PJM Manual 14H: New Service Requests Cycle Process," Rev. 00 (July 26, 2023) for a complete list of all readiness requirements.
90 See "PJM Manual 14H: New Service Requests Cycle Process," Rev. 00 (July 26, 2023) for a complete list of all readiness requirements.

Transition Cycle 2

The application phase for transition cycle 2 (TC2) opened on June 20, 2024, coincident with the close of phase 1 of transition cycle 1. The application phase required all active projects in queues AG2 and AH1 to reapply under the new rules. The application phase of TC2 was open for 180 days, and closed on December 17, 2024. A total of 547 projects, representing 54,703 MW were submitted in TC2. The TC2 application review stage began at the close of the application phase. PJM will review the submissions for required data and deposits and build the models required for the TC2 system impact studies. The TC2 application review stage is expected to be completed early in the second quarter of 2025.

Reliability Resource Initiative (RRI)

On December 13, 2024, PJM submitted modifications to its Open Access Transmission Tariff to add provisions, through a one-time reliability based expansion of the projects in TC2.[91] On February 11, 2025, the Commission approved the RRI tariff modifications.[92] The proposed RRI Tariff revisions created a second TC2 application window that enabled RRI projects to join TC2 and be studied for interconnection during the transition period. PJM received 94 applications (26.6 GW) of RRI projects during the RRI application window. Of these projects, 47 involve uprates, in which existing resources are modified to increase the economic maximum generation capability, and 47 propose building new generation.

The RRI application window did not limit the number and type of projects (or any restriction on fuel type of projects) that may apply to enter the RRI process. However, PJM will restrict the number of RRI projects to be added to TC2 by scoring all the RRI applications using weighted criteria to determine the 50 projects that best satisfy the need for reliable capacity that can be available relatively quickly. The submitted RRI projects are being reviewed to determine which projects will be added to TC2. Final decisions on which RRI projects will be approved are expected to made in the second quarter of 2025.

The MMU supports the stated goals of the December 13th Filing, and supports approval of the December 13th Filing, but also identifies significant flaws that compromise the ability of the proposal to achieve its stated goals.[93] PJM's RRI scoring criteria place undue emphasis on ELCC values rather than on dispatchability. PJM states that the goal is to be fuel and technology neutral. That is not the appropriate objective when there are defined differences in reliability and dispatchability across resource types, by fuel and technology. The goal of the December 13th Filing should be to select the most reliable fuel and technology combinations. PJM also focuses on an arbitrary number of projects (50) that could qualify as RRI projects rather than on a target level of MW needed for reliability. PJM should identify the number of MW, with the required reliability characteristics, that it believes are needed to address PJM's identified reliability shortfall and use the RRI process to obtain those MW. PJM's RRI scoring criteria should be a series of thresholds that must be met in sequence rather than a single formula that considers all elements simultaneously and assumes that the criteria are comparable through relative weights. The first threshold would be that the resource is in the right location to address the identified locational reliability issue. The second threshold would be that the operational characteristics of the resource fully address the identified reliability issue including technology and fuel source(s). The third threshold would be commercial viability within a defined time period with detailed tracking and strong financial incentives. No RRI resource would be approved unless it met all three thresholds.

PJM includes a range of important enforceable provisions that help ensure that the selected RRI resources will actually go online as promised. These provisions include a must offer obligation which is essential to the efficacy of the entire filing as capacity resources that do not offer do not help solve the identified problem. The MMU supports these provisions.

In addition to the one time RRI process, the MMU recommends that PJM establish an ongoing expedited PJM managed queue process to identify commercially viable projects that could help eliminate or reduce the need for specific RMRs or that could address specific reliability needs and allow the identified projects to advance in the queue ahead of projects which have failed

91 See *PJM Interconnection L.LC.* Docket No. ER25-712 (December 13, 2024).
92 190 FERC ¶ 61,084 (February 11, 2025).
93 See IMM Comments. *PJM Interconnection L.LC.* Docket No. ER25-712

to make progress, subject to rules to prevent gaming.[94] While it is important to respect the existing, improved PJM queue process, it is essential to provide strong and clear incentives for projects to actually resolve reliability issues and to actually guarantee timely in service dates in order to help ensure that the queue is not a mirage as it has been in significant part for its recent history. Recognizing that improved queue rules are being implemented, the history of queue projects becoming actual in service capacity resources suggests strongly that such incentives have not been provided by the queue process.

Interconnection Costs for New Projects

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.[95] PJM's process is designed to ensure that new generation is added in a reliable and systematic manner. As part of the interconnection planning process, a series of studies are performed to determine the feasibility, impact, and cost of interconnecting projects in the queue. Interconnection requests are for energy only resources and for capacity resources.

Interconnecting capacity resources must meet a higher standard than energy only resources. For interconnecting capacity resources, PJM performs deliverability studies that ensure that the energy from the proposed generator can be reliably provided to the PJM region. Deliverability studies identify network upgrades needed to ensure that the transmission system is capable of delivering the aggregate system generating capacity at peak load, including the new resource, with all firm transmission service modeled.[96] The interconnection service agreement identifies the transmission modifications needed to maintain the reliability of the transmission system as a result of a new service request. These identified modifications are known as network upgrades. In general, 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.[97] On March 31, 2025, there were 2,031 projects in generation request queues in the status of active, under construction or suspended, and 1,834 active network transmission upgrades. If a project is withdrawn from the queue, the network upgrades associated with that project are no longer required, unless it is required to support another queue project.

While not all projects in the queue require network upgrades, 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. After the execution of an interconnection service agreement, queue projects become part of the RTEP study and the costs of any upgrade later necessary to preserve their Capacity Interconnection Rights are included as part of the overall transmission system costs paid by all transmission customers.

The system impact study is a detailed system analysis performed for new service requests that tests deliverability under peak load conditions and light load conditions. The system impact study identifies system constraints caused by the request and the local upgrades and network upgrades required to solve those constraints. The system impact study includes power flow analysis and short circuit analysis. The power flow analysis includes expected output level from the new resource under summer peak and light load system conditions.[98] PJM's recent improvements to the deliverability analyses reflect more accurate information about the expected performance of intermittent resources, by type of resource (solar fixed, solar tracking, onshore wind and offshore wind), by season (summer, winter and light load) and by region (PJM West, Mid-Atlantic and Dominion), under each of these system conditions. Those modifications are necessary to accurately reflect the expected output of intermittent resources under various seasons and system conditions as the penetration and role of intermittents in PJM increases.[99] For example, the

94 The MMU has consistently supported a stronger role for PJM in addressing immediate reliability needs. As part of the CIR Transfer Efficiency initiative, the MMU proposed to allow PJM to initiate an expedited fast track process to address PJM identified reliability issues. The proposed expedited process would have allowed PJM to open a limited scope expedited reliability process to select projects that address the reliability issues. See "CIR Transfer Efficiency IMM Package," MMU presentation to the PJM Planning Committee (October 8, 2024), <https://www.monitoringanalytics.com/reports/Presentations/2024/IMM_PC_CIR_Transfer_Efficiency_IMM_Package_20241008_v2.pdf>.

95 See OATT Parts IV & VI.

96 See "PJM Manual 14B: PJM Regional Transmission Planning Process," Rev. 57 (September 25, 2024).

97 See "PJM Manual 14G: Generation Interconnection Requests," Rev. 8 (July 26, 2023).

98 Winter peak load is included in the generation deliverability powerflow analysis during the RTEP baseline reliability analysis, but is not currently performed for new interconnection requests. The light load analysis ensures generation deliverability during light load conditions, which is defined as 50 percent of the annual peak demand.

99 See "PJM Manual 14B: PJM Region Transmission Planning Process," Rev. 57 (September 25, 2024).

expected output of onshore wind varies from its maximum facility output to zero, depending on weather conditions, and the expected output levels are used for each system load condition.[100]

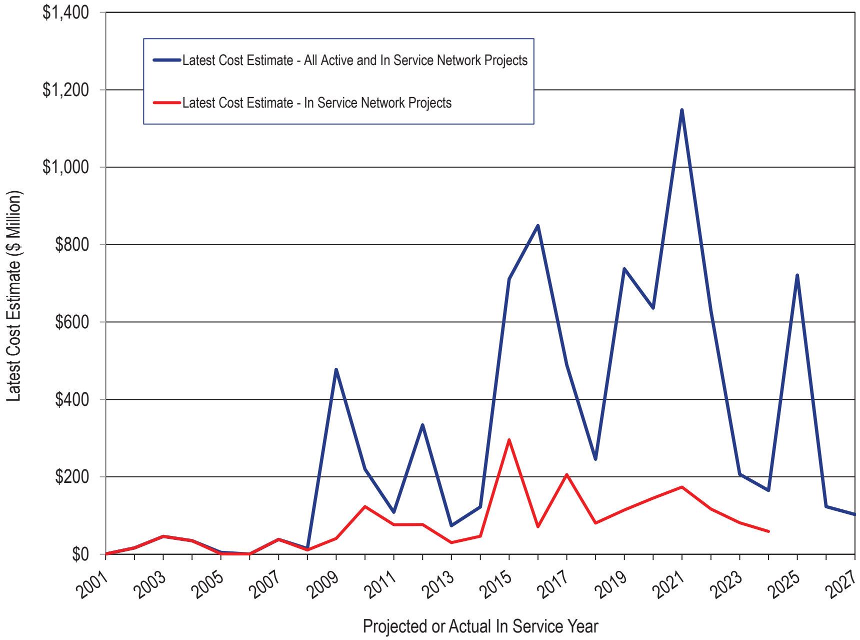
Capacity resources receive Capacity Interconnection Rights (CIRs) based on the deliverable MW which result from a combination of upgrades paid for by each project and existing system capability. Intermittent resources also require CIRs. The level of CIRs required for intermittent resources has been significantly understated because the required CIRs have been based on the derated capacity value of intermittents rather than the maximum energy injections required to achieve the derated value.

After a lengthy stakeholder process, on April 7, 2023, FERC approved updates to PJM's ELCC method that cap the level of an intermittent generator's output used to calculate the generator's reliability contribution (ELCC derated MW) at the generator's CIR level.[101] Rules prior to the FERC order allowed generation at a level greater than the CIR value, and that was therefore not deliverable, to be inappropriately included in the ELCC calculations. For example, if a 100 MW solar resource has CIRs of 60 MW, generation in excess of 60 MW will not be included in the ELCC calculations under the updated rules. Prior to the update, the generation in excess of the CIR level was included, overstating the ELCC ratings and reliability contribution of ELCC resources. The overstatement of intermittent capacity has inefficiently suppressed capacity market clearing prices.[102] [103] In order to retain the prior, incorrectly calculated ELCC values, existing intermittent generating units are required to increase their CIRs by going through an expedited queue process. The ELCC updates established a transitional period during which intermittent generators can be awarded temporary increases in their CIRs based on the availability of transmission system capability.[104] PJM expects a transitional period of four years, beginning with the 2025/2026 Base Residual Auction, to be sufficient time for intermittent resources to reenter the queue and be awarded additional CIRs. New intermittent generators will be required to pay for CIRs consistent with their calculated reliability contribution.

Figure 12-5 shows the latest estimated interconnection costs for new generators (network transmission project cost) by projected and actual in service year for generators that are in service (red line), and for the total of generators in service and still in the queue in active status (blue line). The estimated costs for in service projects (red line) are much lower than the estimated costs that also include all projects in the queue (blue line). The increase in estimated total network upgrade costs for planned projects is a result of the large number of requests in the new services queue and the existing backlog (Figure 12-5). However, as generators withdraw from the queue, the overall network costs decrease. The estimated network upgrade costs for in service projects are much lower. The projected in service dates for network projects are not updated regularly, and therefore, may not be an accurate predictor of when these projects are actually expected to go in service. Figure 12-5 shows a significant level of estimated interconnection costs for resources with projected in service dates as far back as 2008 and a peak for projects with a projected in service date of 2021. Even the costs for projects that are in service are only estimates because PJM does not track final project costs. The final in service costs include only the last estimate provided by PJM before the project went in service. PJM's data collection, management and retention related to transmission spending of all types is inadequate and needs a significant upgrade. The failure to collect data on estimated and final project costs makes it impossible to track transmission project costs for all project types. Given the significance of data to market participants and regulators, the MMU recommends that all queue data and supplemental, network and baseline project data, including projected in service dates and estimated and final costs, be regularly updated with accurate and verifiable data.

100 See "Generation Deliverability Test Modifications: Light Load, Summer & Winter," presented at January 25, 2023 meeting of the Markets and Reliability Committee <https://www.pjm.com/-/media/committees-groups/committees/mrc/2023/20230125/consent-agenda-c---1-generator-deliverability-test-revisions---presentation.ashx>.
101 183 FERC ¶61,009.
102 *See* "Analysis of the 2023/2024 RPM Base Residual Auction," <http://www.monitoringanalytics.com/reports/Reports/2022/IMM_Analysis_of_the_20232024_RPM_Base_Residual_Auction_20221028.pdf>. (October 28, 2022).
103 *See* "Analysis of the 2022/2023 RPM Base Residual Auction—Revised," <https://www.monitoringanalytics.com/reports/Reports/2023/IMM_Analysis_of_the_20222023_RPM_BRA_Revised_20230113.pdf> (January 13, 2023).
104 183 FERC ¶61,009 at 31.

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



Regional Transmission Expansion Plan (RTEP)[105]

The PJM RTEP process is designed to identify needed transmission system additions and improvements to continue to provide reliable service throughout the RTO. The objective of the RTEP process is to provide PJM with an optimal set of solutions necessary to solve reliability issues, operational performance issues and transmission constraints.

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

RTEP Process

The PJM RTEP process is a 24 month planning process that identifies reliability issues for the next 15 year period. This 24 month planning process includes a process to build power flow models that represent the expected future system topology, studies to identify issues, stakeholder input and PJM Board of 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; identify new transmission enhancements that result in economic benefits; and identify economic benefits associated with modification to existing RTEP reliability based enhancements that when modified would relieve one or more economic constraints. The PJM market efficiency analysis is badly flawed and results in concluding there are net benefits when there

105 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. 57 (September 25, 2024).

are not. 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. PJM presents its findings to the TEAC where PJM's findings are reviewed by the stakeholders. While stakeholders can comment on the findings, PJM makes the final decision about what costs will be used for the purpose of calculating the benefit/cost ratio for the project. The benefit/cost ratio is the ratio of the present value of the total annual benefit for 15 years to the present value of the total annual cost for the first 15 years of the life of the enhancement or expansion.

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

PJM's first market efficiency analysis was performed in 2013, prior to Order 1000. The 2013 window was open from August 12, 2013, through September 26, 2013. This window accepted proposals to address historical congestion on 25 identified flowgates. PJM received 17 proposals from six entities. One project, 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, 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.[106]

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.

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

The sixth market efficiency cycle is currently being performed for the 2022/2023 RTEP long term window. The 2022/2023 RTEP long term window was delayed until the reliability violations for the 2022 Window 3 (Dominion data center loads) could be addressed. On November 21, 2023, PJM requested that the Commission grant a waiver to extend the time for PJM to complete its annual review of the benefit/cost analysis associated with the market efficiency cycle.[107] PJM requested the waiver to remain in effect until PJM completes its 2023 annual review no later than the end of the second quarter of 2024. On December 21, 2023, The Commission approved the waiver request.[108] In January 2024, PJM completed updating the 2022/2023 market efficiency base case to include the solution selected from the 2022 Window 3. No flowgates experienced historical congestion that required an open window. PJM will continue to analyze the congestion patterns as part of the 2024/2025 market efficiency cycle.

In February 2024, PJM completed the 2024/2025 market efficiency base case. In May 2024, PJM posted the 2024/2025 Market Efficiency planning assumptions. PJM posted an updated 2024/2025 base case in July 2024, and requested stakeholder feedback by August 31, 2024. PJM is currently preparing the final base case, sensitivity scenarios and congestion drivers. The long term market efficiency window is expected to open on April 11, 2025 and close on June 10, 2025.

The Benefit/Cost Evaluation

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

The total benefit of a project is calculated as the sum of the net present value of calculated energy market benefits and calculated reliability pricing model (RPM) benefits for a 15 year period, starting with the projected in service date of the project. Depending on the type of project being evaluated PJM may measure 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. There are significant issues with PJM's definition of benefits. If done correctly and if FTRs/ARRs returned 100 percent of congestion to load, the benefit/cost analysis would include the total net change in production costs and would not include congestion. The change in production costs correctly measures the changes in cost to load that result from a project.

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. A regional project is any project rated at or above 230 kV. A subregional project is any project rated at less than 230 kv. 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 but, inexplicably, only for those zones where the project reduces the load payments and ignoring zones where the project increases 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 again only for those zones where the project reduces the load energy payments and ignoring zones where the project increases load payments.

In both the regional and subregional analysis, changes in zonal load energy payments subtract the estimated value of any Auction Revenue Rights (ARR) that sink in that zone. An increase in ARR revenues that result from a project would reduce the benefits of that project to load. If done correctly and if ARRs returned 100 percent of congestion to load, the changes in load payments

107 See *PJM Interconnection, L.L.C*, Docket No. ER24-477-000 (November 21, 2023).
108 185 FERC ¶61,212.

would equal the change in production costs. However, the calculated ARR credits in the benefit/cost analysis ignore any increases in ARR MW and include only the reduction in the estimated CLMP differences. Estimated ARR credits are calculated for each simulated year using the most recent planning year's actual ARR MW combined with the simulation's CLMP differences between ARR source and sink points. ARR MW are not adjusted to reflect any increase in ARR MW created by the RTEP upgrade. This means that the reduction in the ARR offset value is too large, the reduction in load payments is overstated, and the value of the proposed project is artificially increased.

The Reliability Pricing Model (RPM) Benefit analysis uses 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 benefit/cost 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. The allocation will be incorrect to the extent that the benefits calculations are incorrect.

There are significant issues with PJM's benefit/cost analysis. The current rules governing benefit/cost analysis of competing transmission projects do not correctly measure the relative costs and benefits of transmission projects. PJM measures benefits as reductions in estimated load charges and production costs in the energy market and reductions in estimated load capacity payments in the capacity market, but PJM's analysis ignores any increases in costs. This means that PJM's benefit/cost analysis systematically overstates the benefits of transmission projects. ARR MW allocations are not adjusted to reflect any potential changes in ARR MW that result from the RTEP upgrade. This means that the reduction in the ARR offset value is too large, the ARR offset is too small, and the result is to artificially increase the value of the proposed project. The correct metric is the change in production costs. In addition, the current rules do not account for the fact that the benefits of projects are uncertain and highly sensitive to the modeling assumptions used, or 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 only appear to, but do not actually exceed the forecasted costs. In addition, there is no after the fact analysis to validate the planning assumptions and there is no data gathered on the actual costs and benefits that would permit such an analysis.

The recent introduction of storage as transmission assets (SATA) raises a number of additional concerns about PJM's benefit/cost analysis. PJM's benefit/cost analysis uses a 15 year forecast for purposes of evaluating benefits and costs of traditional transmission assets with an expected useful life of 50 years or more. Using the same 15 year horizon does not make sense for SATA resources with an expected useful life of 10 years or less, depending on use. Using a 15 year benefit horizon exaggerates 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 benefit/cost threshold test despite having benefits, if correctly calculated, that were less than forecasted costs. This project also illustrates the risks of ignoring potential cost increases given that the costs included in the benefit/cost calculation are nonbinding estimates. The Transource Project was proposed in PJM's 2014/2015 RTEP long term window. PJM's 2014/2015 RTEP long term window was the first market efficiency cycle under Order 1000. The 2014/2015 long term window was open from November 1, 2014, through February 28, 2015. This window accepted proposals to address what PJM terms historical unhedgeable congestion on 12 identified flowgates, where unhedgeable congestion is actually the production costs. The AP South Interface was one of the 12 identified flow gates listed in the 2014/2015 RTEP Long Term Proposal Window Problem Statement.

The initial study had a benefit/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/cost ratio was 0.70, not 2.48. The project should have been rejected on those grounds.

Subsequent PJM 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.

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.[109] Transource appealed the decision at the state and federal level.[110] On May 5, 2022, the state court denied the appeal. On December 6, 2023, the U.S. District Court for the Middle District of Pennsylvania granted the appeal, stating that the Pennsylvania PUC's decision violated the Supremacy Clause and the Dormant Commerce Clause.[111] The federal court found that the PUC's order was not a valid use of the PUC's siting oversight authority. The Pennsylvania PUC filed a notice of appeal with the U.S. Court of Appeals for the Third Circuit on January 10, 2024.[112]

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.[113] 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.[114]

109 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).

110 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.).

111 See *Transource Pennsylvania, LLC et al. v. Steven M. Defrank, et al.*, Case No. 1:21-CV-01101 (M.D. Pa. December 6, 2023).

112 See Transource Pa., LLC v. Dutrieuille, Case No. 21-2567.

113 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>.

114 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>.

While suspended, PJM has stated that it 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.

PJM's 2023 reevaluation of 9A showed a B/C ratio of 0.81 with an in service cost of $420.9 million.[115] [116] In addition, PJM's 2023 reevaluation of 9A showed that Project 9A, given other projects approved after the Project 9A suspension would, if completed, cause uncontrollable overloads on a number of constraints in the PJM modeling analysis starting in 2030.[117] The sum of the positive (energy cost reductions) effects was $371.0 million, a reduction of $818.5 million (-68.8 percent) from the initial study. The sum of negative effects (energy cost increases) was $2,988.1 million, an increase of $2,136.4 million (250.8 percent) in the negative effects from the -$851.7 results of the initial study. The net benefit of the project in the 2023 study was -$2,517.2 million, not the $1,188.1 from the initial study. Using the total benefits (positive and negative) to compare to the net present value of costs in the 2023 analysis, the benefit/cost ratio was -5.71, not 0.81.

On November 26, 2024, PJM filed a request at FERC for a waiver of the timing requirement associated with the Annual Reevaluation Analysis to permit PJM time to update its market efficiency model to include the Board-approved 2024 RTEP Window #1 projects.[118] PJM requested the waiver because the 9A project made the evaluation model infeasible.[119] PJM wanted time to include RTEP projects that it expected to be approved in the first quarter of 2025 in the model. The MMU challenged the need for a reevaluation due to project 9A's repeated failures to meet the benefit/cost ratio requirement for project approval.[120] FERC did not respond to the request for a waiver prior to December 31, 2024. As a result PJM withdrew its request for a waiver and reused its 2023 models to run its 2024 reevaluation of project 9A.

PJM's 2024 reevaluation of 9A used its 2023 market model and, as a result, showed the same result as the 2023 reevaluation. PJM's 2024 reevaluation of 9A showed a Benefit/Cost ratio of 0.81 with an in service cost of $420.9 million.[121] PJM's 2024 reevaluation of 9A showed that Project 9A, given other projects approved after the Project 9A suspension would, if completed, cause uncontrollable overloads on a number of constraints in the PJM modeling analysis starting in 2030.[122] The sum of the positive (energy cost reductions) effects was $371.0 million, a reduction of $818.5 million (-68.8 percent) from the initial study. The sum of negative effects (energy cost increases) was $2,988.1 million, an increase of $2,136.4 million (250.8 percent) in the negative effects from the -$851.7 results of the initial study. The net benefit of the project in the 2024 study was -$2,517.2 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 2024 analysis, the benefit/cost ratio was -5.71, not 0.81.

The MMU does not agree that PJM is required by Schedule 6 to annually reevaluate a market efficiency project that, prior to construction commencing or prior to state approval, fails to meet the PJM benefit/cost criteria (OA Schedule 6 § 1.5.7(f)).

PJM has stated changes in system conditions, such as changes in load forecasts, justify continued reevaluation of market efficiency transmission projects prior to construction commencing or prior to state approval, regardless of the results on the benefit/cost reevaluation in prior years.[123] However, the purpose of the annual benefit/cost analysis of an economic project (OA Schedule 6 § 1.5.7(f)) is to "[t]o assure that new Economic-based Enhancements or Expansions included in the Regional Transmission Expansion Plan continue to be cost

115 Nick Dumitriu, Manager, Market Simulation, Market Efficiency Update presented to the Transmission Expansion Advisory Committee (June 4, 2024) at 21 <https://www.pjm.com/-/media/committees-groups/committees/teac/2024/20240604/20240604-item-04---market-efficiency-update.ashx>.

116 On December 21, 2023, FERC issued an order granting a waiver for delaying the 2023 reevaluation and directed that the analysis be completed by June 30, 2024. PJM presented the results of its 2023 revaluation on June 4, 2024.

117 Nick Dumitriu, Manager, Market Simulation, Market Efficiency Update presented to the Transmission Expansion Advisory Committee (June 4, 2024) at 22-23 <https://www.pjm.com/-/media/committees-groups/committees/teac/2024/20240604/20240604-item-04---market-efficiency-update.ashx>.

118 PJM Waiver Request, November 26, 2024, Docket No. ER25-612-000.

119 Market Simulation, Market Efficiency Update (December 31, 2024) <https://www.pjm.com/-/media/DotCom/committees-groups/committees/teac/2025/20250107/20250107-item-04a---market-efficiency-update---annual-re-evaluation.pdf>

120 Protest of the Independent Market Monitor for PJM, December 10, 2024, Docket No. ER25-612-000.

121 Nick Dumitriu, Manager, Market Simulation, Market Efficiency Update presented to the Transmission Expansion Advisory Committee (December 31, 2024) at 21 <https://www.pjm.com/-/media/DotCom/committees-groups/committees/teac/2025/20250107/20250107-item-04a---market-efficiency-update---annual-re-evaluation.pdf>.

122 Nick Dumitriu, Manager, Market Simulation, Market Efficiency Update presented to the Transmission Expansion Advisory Committee (June 4, 2024) at 22-23 <https://www.pjm.com/-/media/committees-groups/committees/teac/2024/20240604/20240604-item-04---market-efficiency-update.ashx>.

123 Market Simulation, Market Efficiency Update (December 31, 2024) <https://www.pjm.com/-/media/DotCom/committees-groups/committees/teac/2025/20250107/20250107-item-04a---market-efficiency-update---annual-re-evaluation.pdf>.

beneficial, the Office of the Interconnection annually shall review the costs and benefits of constructing such enhancements and expansions." Consideration of changes in system conditions, such as changes in load forecasts, are not a separate criterion in this process but part of the reevaluation of benefit/cost that is required to assure that the new Economic-based Enhancements or Expansions included in the Regional Transmission Expansion Plan continue to be cost beneficial. Absent assurance of continued benefit via the annual analysis (the benefit/cost ratio falls below the 1.25 benefit threshold), the project should be removed from the RTEP.

PJM is currently planning an updated reevaluation of 9A in 2025 that includes RTEP projects that are approved in 2025. The project should be rejected 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.[124] 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 uses the benefit/cost 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 and under allocate costs to MISO members.

No interregional constraints were identified in either PJM's or MISO's regional processes. Therefore, an IMEP study was not required during the 2020/2021 IMEP cycle. No interregional constraints were identified in either PJM or MISO's regional processes. Therefore, an IMEP study was not required during the 2022/2023 IMEP cycle.

PJM and MISO are currently coordinating on interregional congestion issues to identify potential constraints to address in the 2024/2025 IMEP cycle. The joint regional planning committee (JRPC) will make a determination on whether to perform a 2025 coordinated system plan in the second quarter of 2025.

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 reduction over a four year period that exceed the expected installed capacity cost of the proposed project.[125] [126] The TMEP process calculates congestion and assigns congestion costs to load but fails to account for the offsetting value of ARRs and FTRs. 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 ARRs and FTRs. The correct benefit metric is the change in production costs.

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

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

126 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).

The benefit of a proposed TMEP project is calculated as the value of reducing 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. Congestion is correctly calculated as the shadow price (difference in CLMP) times the market flow on the line.

The allocation of costs to each RTO for an approved TMEP project will be in proportion to the benefits, as calculated by PJM and MISO, received by that RTO.[127] The proportion of benefits is calculated using the change in the average shadow price of the constraint times the dfax to the affected downstream buses times the MW of load at the buses. This correctly identifies the proportion of the benefits that go to the load that would benefit from the project. 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 in PJM's RTEP or MISO's MTEP plans, or the identified congestion was caused by outages.[128] 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 (Powerton - Towerline 138 kV) that was approved for implementation by the PJM Board on February 15, 2023, and by the MISO Board on March 23, 2023.[129] [130] [131] For both 2023 and 2024, the RTOs decided not to initiate a Coordinated System Plan (CSP) study, and to continue to assess the impact of planned upgrades and congestion persistence with additional market data. PJM and MISO are currently coordinating on interregional congestion issues to identify potential constraints to address in the 2024/2025 TMEP cycle. The joint regional planning committee (JRPC) will make a determination on whether to perform a 2025 coordinated system plan in the second quarter of 2025.

The PJM and MISO TMEP process for measuring the projected benefits of a TMEP transmission projects is flawed. The current rules incorrectly count congestion as a cost to load without accounting for how the congestion dollars are or are not returned to the load through ARRs and FTRs. The benefit of a TMEP transmission upgrade should be the expected difference in the total production 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 compared 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.[132] When a transmission project addresses a combination of reliability, market efficiency and/or public policy objectives, it is termed a multi driver project. PJM may choose a solution using either the proportional multi driver method or the incremental multi driver method. The proportional

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

128 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>.

129 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>.

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

131 See "PJM-MISO IPSAC," presented at the December 11, 2023 meeting of the PJM-MISO Inter-regional Planning Stakeholder Advisory Committee <https://www.pjm.com/-/media/committees-groups/stakeholder-meetings/ipsac/2024/20240325/20240325-miso-seam-identified-issues-and-solutions-.ashx>

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

method combines separate solutions that address reliability, economics and/or public policy into a single transmission enhancement or expansion project. The incremental method expands 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.[133] On February 20, 2015, the Commission approved the tariff revisions with an effective date of November 12, 2014.[134]

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 a 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 made by two companies (Project 644 + 908) as its preferred solution. The preferred solution has an estimated capital cost of $82.30 million with a PJM determined expected benefit/cost ratio of 1.99.[135] PJM shared its recommendation with MISO for their evaluation. MISO did not indicate any concern with the proposed solution. On February 7, 2023, the PJM Board approved the recommended solution (Project 644 + 908).

The benefit/cost analysis used in the multi driver review is the same flawed benefit/cost 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 to some loads) effects of $169.8 million. The sum of the present value of negative effects (energy cost increases to other loads), 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, even ignoring the use of changes in congestion rather than changes in production costs. Using the total positive and negative effects to compare to the net present value of costs in the PJM's analysis, the benefit/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. Based on the requirement of benefit/cost ratio of 1.25, the energy efficiency portion of the multi driver project should have been rejected.

PJM MISO Interregional Transfer Capability Study (ITCS)

PJM and MISO are performing an Interregional Transfer Capability Study (ITCS).[136] PJM and MISO are coordinating assumptions and models, but will not perform a joint study. The PJM/MISO Interregional Transfer Capability Study is part of PJM's and MISO's strategy to comply with FERC Order No. 1920. The ITCS study appears to mirror PJM's multi driver RTEP process in that it identifies several drivers (efficiency, reliability, transfer needs) for evaluating the value or need for a project, though neither MISO or PJM provide any specificity as to the exact metrics for the evaluation of the benefits or costs within each identified driver, how the drivers will be weighted or how costs of potential projects should be allocated. This stated purpose of the PJM/MISO Interregional Transfer Capability Study is to allow PJM and MISO to consider needs, assumptions, cost allocations and analysis outside the prescriptions of the existing PJM/MIO JOA/CSP process. The goal of the PJM and MISO ITCS is to identify opportunities to enhance transfer capability on an incremental basis over and above other JOA/CSP based studies.

The ITCS study is intended to look out through 2032. In its ITCS study, PJM plans to use a model that blends MISO planning models for MISO's footprint and a set of PJM's long-term planning assumptions for PJM's footprint. PJM is calling this a blended model. PJM's blended model will use the 2023 Regional Transmission Expansion Plan (RTEP) topology with 2022 RTEP Window 3 solutions, the PJM 2024 official Load Forecast, retirements due to federal regulations and states' laws based on the Independent State Agencies Committee (ISAC) workbook and the assumption of sufficient replacement generation or storage for resource adequacy (i.e. to meet 1-in-10 Loss of Load Expectation) selected from interconnection requests and withdrawals.

133 See "PJM Manual 14B: PJM Region Transmission Planning Process," Rev. 57 (September 25, 2024).
134 150 FERC ¶ 61,117 (February 20, 2015).
135 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>.
136 See PJM and MISO Interregional Capability Study (ICTS) FAQ <https://www.pjm.com/-/media/DotCom/planning/interregional-planning/pjm-and-miso-interregional-transfer-capability-study-faq.pdf>.

Preliminary results from the ITCS study identified various transfer, reliability and economic issues from both PJM and MISO.[137] PJM and MISO plan to present final results and near and long term actions resulting from the ITCS study in the first half of 2025.

New Jersey State Agreement Approach for Offshore Wind

In 2021, the New Jersey Board of Public Utilities (NJ BPU) initiated a proposal window under the provisions of the PJM Operating Agreement's State Agreement Approach (SAA) to meet New Jersey's goal of interconnecting up to 7,500 MW of offshore wind.[138] PJM received 80 proposals covering solutions that addressed onshore and offshore reliability criteria and transmission connections. PJM worked with the NJ BPU to analyze the proposals. The NJ BPU selected a proposal to interconnect 3,742 MW of offshore wind to central New Jersey. The total estimated cost for the project is $1.1 billion, with various required in service dates ranging from December 2027 through June 2030. The costs for the NJ BPU offshore wind project will be recovered from customers in the state of New Jersey. On December 6, 2022, the PJM Board approved the BPU's proposal.

On September 22, 2023, Public Service Electric and Gas Company filed an application for an abandoned plant incentive.[139] The filing seeks "authorization for the ability to recover 100 percent of prudently incurred costs for certain transmission upgrades that PSE&G will construct in the event that the [offshore wind] transmission upgrades are abandoned or cancelled (in whole or in part) for reasons that are outside of PSE&G's control."

On October 31, 2023, Danish wind power developer Ørsted announced that it was canceling two major offshore wind projects, Ocean Wind 1 (1,100 MW) and Ocean Wind 2 (1,148 MW), that were planned off the coast of New Jersey. Ørsted is taking a $2.9 billion impairment attributed to Ocean Wind 1.[140]

137 See "PJM/MISO Interregional Transfer Capability Study," presented at the March 7, 2025 meeting of the PJM/MISO Interregional Planning Stakeholder Advisory Committee <https://www.pjm.com/-/media/DotCom/committees-groups/stakeholder-meetings/ipsac/2025/20250307/20250307-miso-pjm-ipsac-interregional-transfer-capability-study-itcs-to-pjm---working-draft.pdf>.

138 See PJM Operating Agreement, Schedule 6, Section 1.5.9

139 See *Public Service Electric and Gas Company*, Docket No. ER23-2916 (September 22, 2023).

140 Ørsted, Ørsted ceases development of its US offshore wind projects Ocean Wind 1 and 2, takes final investment decision on Revolution Wind, and recognises DKK 28.4 billion impairments (October 31, 2023) <https://orsted.com/en/company-announcement-list/2023/10/oersted-ceases-development-of-its-us-offshore-wind-73751>.

Long Term Regional Transmission Planning

On May 13, 2024, the Commission issued Order No. 1920 which requires public utility transmission providers to engage in long-term regional transmission planning over a 20-year planning horizon, develop long-term scenarios to identify long-term transmission needs and enable the identification and evaluation of transmission facilities to meet those transmission needs. Order No. 1920 also requires transmission providers to determine a cost allocation method for long-term regional transmission facilities, make other reforms to enhance transparency in local transmission planning, to correctly size transmission projects and include interregional transmission coordination to support the development of cost-effective projects.[141]

On November 21, 2024, the Commission issued Order No. 1920-A.[142] Order No. 1920-A significantly expanded the role of States in the long-term regional transmission planning. Order No. 1920-A requires states' input into regional transmission planning and cost allocation processes, both in the transmission providers' development of Order No. 1920 compliance filings and the ongoing implementation of these reforms in the future. Order No. 1920-A also increases the states' role in: (i) developing long term scenarios; (ii) requesting additional scenarios beyond the three Long-Term Scenarios required by Order No. 1920; (iii) developing the evaluation processes and criteria for selecting new transmission facilities in the long-term regional transmission; (iv) developing cost allocation approaches for selected transmission facilities; and (v) voluntary funding opportunities.

PJM requested that the Commission extend PJM's deadline to comply with Order No. 1920's compliance directives by six months, (to December 12, 2025), while leaving the implementation deadline of two years after the initial due date of the compliance filing (June 12, 2027) unchanged. The extension was requested to accommodate the States' broader role required by Order No. 1920-A in developing Order No. 1920-compliant Long-Term Regional Transmission Planning protocols.[143]

141 See *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation, Order No. 1920*, 187 FERC ¶ 61,068 (2022).

142 See *Order on rehearing and clarification, Order No. 1920-A*, 189 FERC ¶ 61,126 (2024).

143 See PJM Interconnection, L.L.C., Docket No. RM21-17-000 (December 20, 2024).

Supplemental Transmission Projects

Supplemental projects are asserted to be "transmission expansions or enhancements that are not required for compliance with PJM criteria and are not state public policy projects according to the PJM Operating Agreement. These projects are used as inputs to RTEP models, but are not required for reliability, economic efficiency or operational performance criteria, as determined by PJM."[144] 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.[145] 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. Baseline projects are RTEP projects needed for reliability. 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 12-61 and Table 12-62 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.

PJM's data collection, management and retention related to transmission spending of all types is inadequate and needs a significant upgrade. The failure to collect data on estimated and final project costs makes it impossible to track transmission project costs for all project types. Given the significance of data to market participants and regulators, the MMU recommends that all queue data and supplemental, network and baseline project data, including projected in service dates and estimated and final costs, be regularly updated with accurate and verifiable data.

144 See PJM. Planning. "Transmission Construction Status," (Accessed on March 31, 2025) <https://www.pjm.com/planning/project-construction>.

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

Figure 12-6 Cost estimate of baseline and supplemental projects by expected in service year: January 1, 1998 through December 31, 2025

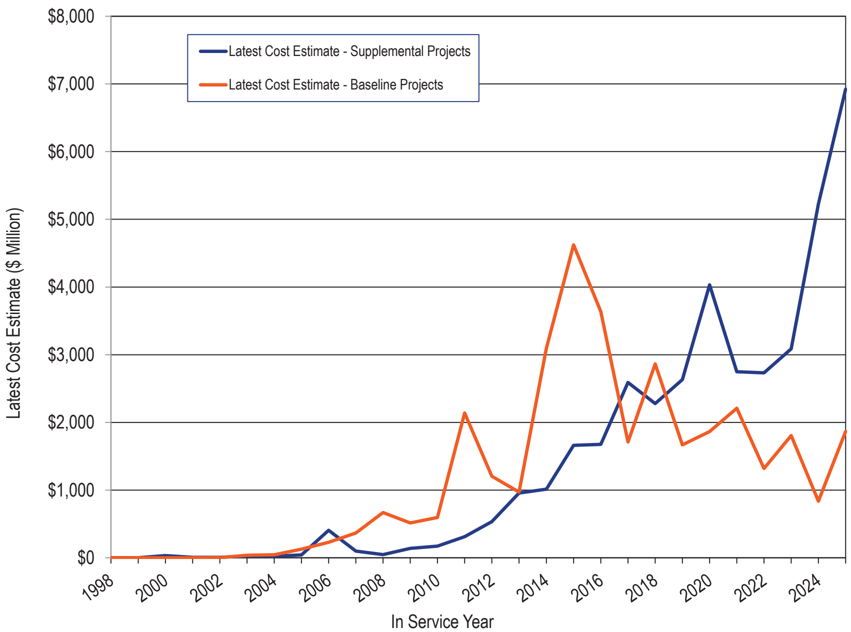


Table 12-61 shows the number of supplemental projects by expected in service year for each transmission zone. The average number of supplemental projects in each expected in service year increased by 1,155.0 percent, from 20 for years 1998 through 2007 (pre Order No. 890) to 251 for years 2008 through 2025 (post Order No. 890). As of March 31, 2025, there are 1,776 supplemental projects with expected in service dates between January 1, 2025 and December 31, 2029.

Table 12-61 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	1	0	0	0	0	0	0	0	0	3
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	7	4	0	41
2012	0	5	0	6	4	1	2	0	7	3	16	1	0	2	0	0	0	1	0	0	6	11	0	65
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	10	15	0	124
2015	4	15	0	2	9	1	37	0	8	4	17	5	3	2	0	0	0	1	0	4	7	23	0	142
2016	6	17	0	4	17	0	26	0	6	2	13	4	2	0	1	0	0	3	2	3	11	29	0	146
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	25	0	287
2019	3	163	0	4	30	5	14	2	16	1	33	8	5	3	14	0	0	1	15	0	15	27	0	359
2020	5	132	0	4	35	6	12	7	13	1	30	2	6	9	17	0	0	3	33	1	17	23	0	356
2021	4	154	0	6	31	8	4	5	13	2	22	0	8	16	23	0	0	22	24	0	19	23	0	384
2022	1	149	0	10	30	5	10	6	9	1	28	2	6	14	33	0	0	5	29	0	18	17	0	373
2023	5	169	0	17	21	10	6	4	9	1	38	4	6	7	26	2	0	5	12	5	15	20	0	382
2024	7	349	1	26	28	11	8	18	3	0	34	4	10	18	24	0	0	8	25	4	15	17	0	610
2025	3	359	3	21	39	12	10	20	12	3	47	0	6	29	42	0	0	5	63	7	20	17	0	718
2026	4	146	3	30	22	5	18	15	11	2	34	3	6	24	30	0	0	2	26	2	28	7	0	418
2027	4	143	5	27	22	1	6	16	5	3	25	5	8	13	14	0	5	1	4	0	22	19	0	348
2028	7	83	1	8	9	4	4	5	6	0	17	1	2	8	0	0	0	3	10	11	14	8	0	201
2029	6	41	0	8	4	3	0	4	2	0	3	0	2	0	1	0	0	1	1	1	5	9	0	91
2030	0	60	1	0	3	0	0	3	0	0	5	0	0	0	0	0	0	0	0	0	7	0	0	79
2031	0	36	0	0	1	0	0	0	1	0	0	1	0	0	0	0	0	0	0	0	0	0	0	39
2032	1	4	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	6
2033	0	0	0	1	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	16	0	0	18
2034	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	6	0	4	0	0	10
2035	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
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	108	2,348	14	251	357	85	269	105	149	64	462	160	82	154	233	2	5	77	263	41	322	375	0	5,926

Table 12-62 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 3,310.9 percent, from $64.5 million for years 1998 through 2007 (pre Order No. 890) to $2.2 billion for years 2008 through 2025 (post Order No. 890). As of March 31, 2025, the 1,776 supplemental projects with expected in service dates between January 1, 2025 and December 31, 2029, have a total cost estimate of $24.3 billion.

Table 12-62 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	$6.99	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$6.99
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	$14.66	$0.00	$10.12	$0.00	$0.00	$2.57	$0.00	$0.00	$0.00	$0.02	$10.98	$0.00	$0.00	$0.00	$0.00	$0.00	$0.50	$0.00	$0.00	$0.00	$0.00	$0.00	$42.91
2006	$4.03	$309.70	$0.00	$0.93	$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	$406.14
2007	$0.56	$2.06	$0.00	$9.85	$0.00	$37.61	$4.64	$0.00	$0.00	$31.75	$0.00	$9.71	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.34	$2.28	$0.00	$98.80
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	$1.59	$0.00	$0.00	$47.32
2009	$0.77	$0.90	$0.00	$12.22	$0.00	$5.00	$21.11	$0.00	$0.00	$19.60	$2.12	$7.35	$0.00	$0.00	$0.00	$0.00	$0.00	$48.10	$2.73	$0.00	$0.16	$17.60	$0.00	$137.66
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	$305.30	$0.00	$1,012.86
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	$741.91	$0.00	$1,660.02
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	$742.48	$0.00	$1,675.74
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	$537.85	$0.00	$2,278.99
2019	$64.30	$1,164.94	$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	$2,632.41
2020	$59.58	$920.44	$0.00	$0.30	$115.41	$62.58	$78.09	$14.36	$72.06	$6.40	$258.72	$39.50	$25.61	$2.30	$23.10	$0.00	$0.00	$2.40	$72.70	$102.70	$215.29	$1,959.38	$0.00	$4,030.92
2021	$86.54	$1,088.72	$0.00	$9.50	$184.21	$32.52	$140.90	$17.79	$117.39	$18.90	$98.40	$0.00	$25.67	$46.70	$85.89	$0.00	$0.00	$73.40	$63.48	$0.00	$197.67	$460.84	$0.00	$2,748.52
2022	$81.40	$756.85	$0.00	$19.32	$205.52	$190.13	$147.60	$21.46	$64.32	$45.00	$194.60	$9.38	$22.12	$34.84	$123.34	$0.00	$0.00	$72.80	$59.79	$0.00	$231.92	$450.83	$0.00	$2,731.22
2023	$59.10	$851.64	$0.00	$49.09	$164.51	$18.35	$48.34	$25.60	$112.27	$0.00	$345.67	$87.57	$29.77	$10.85	$134.20	$68.77	$0.00	$24.40	$20.07	$218.84	$189.73	$628.26	$0.00	$3,087.03
2024	$87.60	$2,561.00	$20.00	$68.01	$198.90	$23.84	$219.60	$202.60	$31.73	$0.00	$486.30	$95.30	$59.18	$89.77	$104.80	$0.00	$0.00	$172.73	$78.88	$2.69	$204.85	$517.54	$0.00	$5,225.32
2025	$50.53	$2,483.74	$25.50	$241.31	$584.84	$141.00	$201.90	$94.85	$115.62	$58.25	$952.86	$0.00	$56.10	$134.17	$173.12	$0.00	$0.00	$30.70	$176.73	$594.24	$359.20	$448.63	$0.00	$6,923.29
2026	$85.71	$1,485.10	$32.74	$306.58	$369.82	$398.00	$859.50	$118.66	$84.14	$0.00	$753.89	$69.18	$62.00	$131.90	$164.79	$0.00	$0.00	$36.20	$76.20	$1.10	$658.30	$244.20	$0.00	$5,938.01
2027	$91.90	$1,385.25	$47.00	$166.77	$367.52	$0.00	$319.00	$129.51	$67.02	$168.50	$780.90	$104.60	$92.66	$91.42	$171.40	$0.00	$4.40	$36.00	$16.80	$0.00	$341.98	$685.20	$0.00	$5,067.83
2028	$131.59	$673.09	$15.30	$36.73	$230.12	$491.55	$540.90	$33.80	$52.12	$0.00	$522.95	$15.00	$31.66	$22.46	$0.00	$0.00	$0.00	$53.00	$251.70	$8.39	$477.66	$497.78	$0.00	$4,085.80
2029	$193.40	$220.35	$0.00	$72.15	$59.72	$276.00	$0.00	$46.20	$47.46	$0.00	$299.02	$0.00	$30.10	$0.00	$26.40	$0.00	$0.00	$82.00	$138.00	$0.50	$171.30	$604.50	$0.00	$2,267.10
2030	$0.00	$301.74	$29.00	$0.00	$43.60	$0.00	$0.00	$74.30	$0.00	$0.00	$85.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$39.75	$0.00	$0.00	$573.39
2031	$0.00	$292.90	$0.00	$0.00	$80.00	$0.00	$0.00	$0.00	$2.40	$0.00	$0.00	$42.50	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$417.80
2032	$50.00	$242.23	$0.00	$1.90	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$294.13
2033	$0.00	$0.00	$0.00	$1.90	$0.00	$0.00	$0.00	$0.00	$0.00	$30.40	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$242.17	$0.00	$0.00	$274.47
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	$89.40	$0.00	$0.00	$532.40
2035	$0.00	$107.10	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$107.10
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	$1,287.58	$17,288.85	$169.54	$1,119.70	$3,298.47	$1,802.05	$3,777.36	$779.43	$1,059.00	$581.10	$5,686.03	$812.60	$473.81	$585.06	$1,095.09	$68.77	$4.40	$995.53	$1,496.98	$1,149.16	$4,438.11	$10,987.76	$0.00	$58,956.38

On September 28, 2023, the Office of Ohio Consumers' Counsel filed a complaint regarding the impact of the volume and costs of supplemental projects on consumers. The complaint requests that the Commission develop a mechanism, to be included in the PJM Tariff and Operating Agreement, whereby "FERC would review the need, prudence and cost-effectiveness of local transmission projects in Ohio." The complaint also requests the Commission to appoint an Independent Transmission Monitor (ITM) to assist "in reviewing the planning, need, prudence and cost-effectiveness of local transmission projects for consumers in Ohio", and to "consider precluding the Ohio Transmission Utilities from using formula rates for establishing transmission rates."[146] The Office of Ohio Consumers' Counsel's complaint is pending.

On December 19, 2024, a group of consumer interests filed against multiple transmission owners and RTOs/ISOs.[147] The complaint alleges that provisions in the tariffs of the transmission owning utilities and the RTOs/ISOs inappropriately authorize individual transmission owners to plan facilities rated at 100 kilovolts kV and above without regard to efficiency or cost-effectiveness. The complaint does not challenge the rates for any specific locally planned projects, but, rather, alleges that the cumulative effect of tariff provisions allowing local planning of transmission projects rated at 100 kV and above results in unjust and unreasonable transmission rates.[148] The complaint requests issuance of an order that, for transmission facilities rated at 100 kV and above, requires: (i) removal of planning from transmission owner tariffs (and RTO tariffs that confirm such transmission owner planning); (ii) amendment of regional planning tariffs to require that all planning be done at the regional or interregional level (specifying facilities reaching the end of operational life); and (iii) amendment of regional planning tariffs be to require that the regional planning within the existing Order No. 1000 regions be conducted by independent transmission system planners.[149] The complaint recommends that independent transmission planners be structured similar to independent market monitors or be included in an expanded market monitoring function.[150] The consumer interests' planning complaint is pending.

The MMU recommends, to increase the role of competition, that the exemption of supplemental projects 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.[151]

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 require competition to build such projects.

Competitive Planning Process Exclusions

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

- **Immediate Need Exclusion.** If the violation needs to be resolved within three years or less, all such projects are excluded from competition. The local Transmission Owner is the Designated Entity.[152]

  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

146 See Office of the Ohio Consumers' Counsel v. PJM, et al., Docket No. EL23-105 (September 28, 2023).
147 See Industrial Energy Consumers of America v. PJM, et al., Docket No. EL25-44-000 (December 19, 2024).
148 *Id.* at 11.
149 *Id.* at 42–43.
150 *Id.*, Attachment C (Declaration of Michael A. Giberson) at 36:11–37:8.
151 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), *affirmed*, American Municipal Power, Inc., et al. v. FERC, Case No. 20-1449 (D.C. Cir. November 17, 2023), 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).
152 See OA Schedule 6 § 1.5.8(m).

1000.[153] 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.[154] 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.[155] The decision was largely based on deference to FERC expertise.[156]

- **Below 200kV.** All projects at voltages less than 200kV are excluded from competition. The local Transmission Owner is the Designated Entity.[157] Some supplemental projects are in this category.
- **Substation Equipment.** If the limiting element(s) is substation equipment, such projects are excluded from competition. The local Transmission Owner is the Designated Entity.[158] Some supplemental projects are in this category.

While the PJM Operating Agreement defines 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 require 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.

153 169 FERC ¶ 61,054 (2019).
154 LSP Transmission Holdings II, LLC v. FERC, 45 F.4th 979.
155 *Id.* at 999.
156 *Id.*
157 See OA Schedule 6 § 1.5.8(n).
158 See OA Schedule 6 § 1.5.8(p).

Dominion Data Center Alley Immediate Need and Long Term Solution

Dominion presented 44 supplemental project requests to serve new data center load through the summer of 2025. PJM identified the need for additional baseline reinforcements to support the load growth. Rather than a competitive process, PJM decided to designate the upgrades as immediate need and allowed Dominion to construct these lines.[159] [160]

The 2022 RTEP Window 3 addressed long term reliability needs as well as the additional baseline reinforcements for Data Center Alley. The proposal window was open from February 24, 2023, to May 31, 2023, and received 72 submissions from 10 entities. The cost estimate for the total scope of work was $5.1 billion, $1.4 billion of which was for the necessary baseline upgrades specific to the Data Center Alley reinforcements.[161] The proposed Data Center Alley solution includes 500kV and 230kV lines extensions, the reconductoring of multiple 230kV lines and substation work.[162]

On December 8, 2023, the Maryland Office of People's Counsel (MDOPC) submitted a letter to the PJM Board.[163] The letter requested that the PJM Board defer the December 11, 2023, vote on the 2022 RTEP Window 3 proposal. The MDOPC letter cited concerns regarding the scale, scope and cost of the proposal. Additionally, the MDOPC expressed concerns that "the current failure to unpack the relative contribution of each of the "drivers" of the need for the W3 projects makes it impossible for the public to understand how cost causation principles apply to the projects." On December 11, 2023, the PJM Board approved the recommended solution. PJM filed the RTEP on January 10, 2024, and the Commission accepted it by order issued April 8, 2024.[164]

159 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>.
160 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>.
161 See "*Transmission Expansion Advisory Committee (TEAC) Recommendations to the PJM Board*," December 2023. <https://www.pjm.com/-/media/committees-groups/committees/teac/2023/20231205/20231205-pjm-teac-board-whitepaper-december-2023.ashx>.
162 See "*Reliability Analysis Report: 2022 RTEP Window 3*," December 8, 2023. <https://www.pjm.com/-/media/committees-groups/committees/teac/2023/20231205/20231205-2022-rtep-window-3-reliability-analysis-report.ashx>.
163 See "MD Office of People's Counsel Letter regarding 2022 RTEP Window 3 Procurement," <https://www.pjm.com/-/media/about-pjm/who-we-are/public-disclosures/20231208-pjm-board-letter-2023-12-08-md-opc-final.ashx>.
164 See 187 FERC ¶ 61,012. Maryland Office of the People's Counsel filed a protest, which the Commission determined was outside of the scope of the RTEP filing.

Comparative Cost Framework

The MMU recommended that rules be implemented to require that project cost caps on new transmission projects be part of the evaluation of competing projects. On May 24, 2018, the PJM Markets and Reliability Committee (MRC) approved a motion that required PJM, with input from the MMU, to develop a comparative cost framework to evaluate the quality and effectiveness of binding cost containment proposals versus proposals without cost containment provisions. On March 20, 2020, the Commission approved PJM's filing to amend the PJM Operating Agreement to incorporate this requirement.[165]

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 data and 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.[166] 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 considered whether storage devices should be included in the RTEP process as transmission assets.[167] On February 24, 2021, the Markets and Reliability Committee (MRC) voted to defer endorsement of governing document language associated with Storage as a Transmission Asset in reliability planning. The MRC chose to defer the language until a comprehensive proposal addressing all aspects of incorporation of storage resources into markets, operations and planning. The issue is currently on hold in the stakeholder process.

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.[168] 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.[169]

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

165 See 170 FERC ¶ 61,243 (2020).
166 See "PJM Manual 14F: Competitive Planning Process," Rev. 9 (April 27, 2022).
167 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>.
168 See *AEP*, Docket No. EL20-58 (July 22, 2020).
169 173 FERC ¶ 61,264 (2020).

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.[170]

An RTEP project can be approved by the PJM Board if the project ensures compliance with NERC, regional and local transmission owner planning criteria or to address market efficiency congestion relief. These projects are considered Baseline Projects. PJM Board approved RTEP projects that are necessary to allow new generation to interconnect reliably are considered Network Projects.

In the first three months of 2025, the PJM Board approved a net change of $7.7 billion in transmission upgrades. As of March 31, 2025, the PJM Board had approved $57.8 billion in transmission system enhancements since 1999.

Qualifying Transmission Upgrades (QTU)

A Qualifying Transmission Upgrade (QTU) is an upgrade to the transmission system, financed and built by market participants, 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 March 31, 2025, no QTUs have cleared a BRA or IA.

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

Cost Allocation

Required transmission enhancements are categorized as: supplemental, network or baseline upgrades. The cost allocation of the transmission enhancements depends on the category of upgrades.

Supplemental Upgrade Cost Allocation

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."[171] Supplemental projects are exempt from competition. The costs of supplemental projects are allocated 100 percent to the zone in which the transmission facilities are located.[172]

Network Upgrade Cost Allocation

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.[173] PJM's process is designed to ensure that new generation is added in a reliable and systematic manner. The process assigns the upgrade costs to the project or projects that are causing the costs to be incurred. As part of the interconnection planning process, a series of studies are performed to determine the feasibility, impact, and cost of interconnecting projects in the queue. The interconnection service agreement identifies the transmission modifications needed to maintain the reliability of the transmission system as a result of a new service request. These identified modifications are known as network upgrades. For required network upgrades under the new cluster based service request cycles, the costs of the network upgrades are assigned to individual projects that caused the costs to be incurred.[174]

171 See PJM. "Transmission Construction Status," (Accessed on March 31, 2025) <https://www.pjm.com/planning/m/project-construction>.
172 See OATT Schedule 12(a)(iii).
173 See OATT Parts IV & VI.
174 See "PJM Manual 14H: New Service Requests Cycle Process," Rev. 00 (July 26, 2023).

Baseline Upgrade Cost Allocation

The PJM RTEP process is designed to identify needed transmission system additions and improvements to continue to provide reliable service throughout the RTO. Typically, load growth creates conditions that may create violations of reliability criteria, which in turn require upgrades. The PJM RTEP identifies necessary upgrades to remain compliant with national and regional reliability standards. These modifications are baseline upgrades. Baseline upgrades can also include market efficiency projects.

The costs of regional baseline facilities are allocated 50 percent on a load-ratio share and 50 percent on a directionally weighted solution based DFAX method.[175]

The costs of the necessary lower voltage facilities required to support the regional baseline facilities with estimated costs greater than or equal to $5 million are assigned on a directionally weighted solution based DFAX method.

The costs of the necessary lower voltage facilities required to support the regional baseline facilities with estimated costs below $5 million are assigned to the zone where the upgrade is located.

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."[176] FERC convened a technical conference on January 12, 2016, to address the complaints in multiple proceedings and to address these two core issues.[177]

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.[178] 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 in 2022 found that FERC had failed to explain its distinction between the projects eligible to use the dfax method and those not eligible.[179] The Court objected that without adequate explanation: "The Bergen project 'addresses a non-flow related reliability issue,' just like the non-flow-based stability issue in Artificial Island, but FERC had treated the two projects differently."[180] The Court also rejected the 0.01 distribution cutoff factor as "absurd."[181] The Court remanded issues concerning PJM's solution based dfax method to FERC, where the matter is now pending.[182]

It is clear that the allocation issues are difficult. Nonetheless, allocation methods affect the efficiency of the markets. Allocation methods also affect the degree to which transmission upgrades required to serve data center load are allocated to other customers. 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

175 See "PJM Manual 14B: PJM Region Transmission Planning Process," Rev. 57 (September 25, 2024) for a complete explanation of the directionally weighted solution based DFAX method.
176 153 FERC ¶ 61,245 at P 35 (2015).
177 See Docket Nos. EL15-18-000 (ConEd), EL15-67-000 (Linden), and EL15-95-000 (Artificial Island).
178 See 170 FERC ¶ 61,122 (2020).
179 See *Consolidated Edison v. FERC et al.*, 45 F.4th 265 (D.C. Cir. August 9, 2022).
180 *Id.* at 9.
181 See *id.*
182 See FERC Docket Nos. EL15-67-000, et al.

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.

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. Line ratings directly affect 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 costs for the interconnection of 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. The fact that PJM rules continue to fail to ensure the return of 100 percent of congestion costs to the load that pays them means that higher congestion increases costs to load.

LMP may, at times, be set by transmission constraint 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 constraint penalty factors. The shadow price directly affects the LMP. Transmission constraint penalty factors were fully implemented in PJM pricing effective February 1, 2019.[183]

Transmission line ratings can result in short term, significant increases in prices as a result of the application of transmission constraint 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 control percent on transmission limits applied in SCED by the setting the limit to an average of 95 percent of its actual limit.[184] Violation of these reduced control percent line ratings results in penalty factors setting prices in SCED.[185]

Holding aside the issues with operators reducing the control percent in SCED, the more important point is that the underlying line ratings have a significant impact on the cost of energy and capacity but have never been reviewed or standardized by ISOs/RTOs or by regulators. The line ratings issues will begin to be addressed beginning on July 12, 2025.[186]

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

183 For more information, see the *2024 Annual State of the Market Report for PJM*, Section 3: Energy Market.

184 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>.

185 See the *2024 Annual State of the Market Report for PJM*, Section 3: Energy Market.

186 *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").

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.[187]

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

In PJM, transmission owners use a range of ratings by duration.[188] 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.[189]

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. 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

187 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).
188 See "PJM Manual 03: Transmission Operations," Rev. 67 (November 21, 2024) § 2.1.1, at p 30.
189 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.

temperatures and wind speed when relevant.[190] 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.[191] All line rating changes and the detailed reasons for those changes should be public and fully transparent.

The Commission 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; 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.[192] [193]

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."[194]

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.

190 *See* "Transmission Owner Ratings Development and Reporting in PJM," presented at May 3, 2018 meeting of the Planning Committee.
191 *See* the *2024 Annual State of the Market Report for PJM*, Section 3: Energy Market.
192 *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").
193 *See* 18 CFR § 35.28(c)(5)&(g)(13).
194 Order No. 881-A at P 91.

By letter order issued November 22, 2023, the Commission accepted PJM's filing in compliance with Order Nos. 881 and 881-A, to be implemented no later than July 12, 2025.[195]

Order No. 881 did not require the use of dynamic line ratings ("DLR") based on an insufficient record.[196] On June 27, 2024, the Commission issued an Advanced Notice of Proposed Rulemaking in Docket RM24-6 on the implementation of dynamic line ratings.[197]

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 small 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.

195 See Docket No. ER22-2359-000. PJM must notify the Commission of the effective date no later than November 12, 2024.
196 Order No. 881 at PP 25, 254.
197 See 187 FERC ¶ 61,201.

PJM developed technical reference guides to aid in the understanding and consideration of grid enhancing technologies on the PJM system. The technical reference guides provide additional information on dynamic line ratings, advanced power flow controllers, topology control and optimization and advanced conductors.[198]

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.[199] 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.[200] The specific timeline is shown in Table 12-64.[201]

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 2023/2024 planning period and in the first 10 months of the 2024/2025 planning period, regardless of when they were initially submitted.[202] The outage data for the day-ahead market are for outages scheduled to occur from January 2015 through March 2025.

Transmission outages are categorized by duration: greater than 30 calendar days; less than or equal to 30 calendar days; greater than five calendar days; less than or equal to five calendar days.[203] Table 12-63 shows that 73.9 percent of requested outages were planned for less than or equal to five days and 10.3 percent of requested outages were planned for greater than 30 days in the first 10 months of the 2024/2025 planning period. Table 12-63 also shows that 76.3 percent of the requested outages were planned for less than or equal to five days and 8.8 percent of requested outages were planned for greater than 30 days in the 2023/2024 planning period.

Table 12-63 Transmission facility outage request summary by planned duration: June 2023 through March 2025

	2023/2024 (12 months)		2024/2025 (10 months)	
Planned Duration (Days)	Outage Requests	Percent of Total	Outage Requests	Percent of Total
<=5	14,916	76.3%	11,810	73.9%
>5 & <=30	2,903	14.9%	2,525	15.8%
>30	1,718	8.8%	1,640	10.3%
Total	19,537	100.0%	15,975	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 12-64.[204]

The purpose of the rules defined in Table 12-64 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.[205]

198 See PJM. About PJM "Grid Optimization Solutions," <https://www.pjm.com/about-pjm/advanced-technologies/grid-optimization-solutions>.
199 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. 67 (Nov. 21, 2024).
200 See PJM, "Manual 3: Transmission Operations," Rev. 67 (Nov. 21, 2024).
201 See PJM, "Manual 3: Transmission Operations," Rev. 67 (Nov. 21, 2024).
202 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.
203 *Id.* at 70.
204 See PJM, "Manual 3: Transmission Operations," Rev. 67 (Nov. 21, 2024).
205 See "Report of PJM Interconnection, L.L.C. on Transmission Oversight Procedures," Docket No. EL01-122-000 (November 2, 2001).

Table 12-64 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

Table 12-65 shows a summary of requests by received status. In the first 10 months of the 2024/2025 planning period, 41.3 percent of outage requests received were late. In the 2023/2024 planning period, 38.0 percent of outage requests received were late.

Table 12-65 Transmission facility outage requests by received status: June 2023 through March 2025

	2023/2024 (12 months)				2024/2025 (10 months)			
Planned Duration (Days)	On Time	Late	Total	Percent Late	On Time	Late	Total	Percent Late
<=5	9,808	5,108	14,916	34.2%	7,381	4,429	11,810	37.5%
>5 & <=30	1,642	1,261	2,903	43.4%	1,354	1,171	2,525	46.4%
>30	660	1,058	1,718	61.6%	637	1,003	1,640	61.2%
Total	12,110	7,427	19,537	38.0%	9,372	6,603	15,975	41.3%

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.[206]

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.[207] Table 12-66 is a summary of outage requests by emergency status. Of all outage requests scheduled to occur in the first 10 months of the 2024/2025 planning period, 12.9 percent were for emergency outages. Of all outage requests scheduled to occur in the 2023/2024 planning period, 11.8 percent were for emergency outages.

Table 12-66 Transmission facility outage requests by emergency: June 2023 through March 2025

	2023/2024 (12 months)				2024/2025 (10 months)			
Planned Duration (Days)	Emergency	Non Emergency	Total	Percent Emergency	Emergency	Non Emergency	Total	Percent Emergency
<=5	1,663	13,253	14,916	11.1%	1,432	10,378	11,810	12.1%
>5 & <=30	357	2,546	2,903	12.3%	325	2,200	2,525	12.9%
>30	282	1,436	1,718	16.4%	296	1,344	1,640	18.0%
Total	2,302	17,235	19,537	11.8%	2,053	13,922	15,975	12.9%

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."[208]

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.

206 See PJM, "Manual 3: Transmission Operations," Rev. 67 (Nov. 21, 2024). 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).

207 PJM, "Manual 3: Transmission Operations," Rev. 67 (Nov. 21, 2024).

208 PJM added this definition to Manual 38 in February 2017. PJM, "Manual 38: Operations Planning," Rev. 19 (Jan. 23, 2025).

Table 12-67 is a summary of outage requests by congestion status. Of all outage requests submitted to occur in the first 10 months of the 2024/2025 planning period, 9.6 percent were expected to cause congestion. Of all the outage requests that were expected to cause congestion, 4.8 percent (74 out of 1,526) were denied by PJM in the first 10 months of the 2024/2025 planning period and 20.3 percent (310 out of 1,526) were cancelled (Table 12-69). Of all outage requests submitted to occur in the 2023/2024 planning period, 7.8 percent were expected to cause congestion. Of all the outage requests that were expected to cause congestion, 4.1 percent (62 out of 1,520) were denied by PJM in the 2023/2024 planning period and 17.9 percent (272 out of 1,520) were cancelled (Table 12-69).

Table 12-67 Transmission facility outage requests by congestion: June 2023 through March 2025

	2023/2024 (12 months)				2024/2025 (10 months)			
Planned Duration (Days)	Congestion Expected	No Congestion Expected	Total	Percent Congestion Expected	Congestion Expected	No Congestion Expected	Total	Percent Congestion Expected
<=5	1,052	13,864	14,916	7.1%	1,061	10,749	11,810	9.0%
>5 & <=30	309	2,594	2,903	10.6%	310	2,215	2,525	12.3%
>30	159	1,559	1,718	9.3%	155	1,485	1,640	9.5%
Total	1,520	18,017	19,537	7.8%	1,526	14,449	15,975	9.6%

Table 12-68 shows the outage requests summary by received status, congestion status and emergency status. In the first 10 months of the 2024/2025 planning period, 28.6 percent of requests were submitted late and were nonemergency while 1.6 percent of requests (262 out of 15,975) were late, nonemergency, and expected to cause congestion. In the 2023/2024 planning period, 26.4 percent of requests were submitted late and were nonemergency while 1.2 percent of requests (229 out of 19,537) were late, nonemergency, and expected to cause congestion.

Table 12-68 Transmission facility outage requests by received status, emergency and congestion: June 2023 through March 2025

		2023/2024 (12 months)				2024/2025 (10 months)			
Received Status		Congestion Expected	No Congestion Expected	Total	Percent of Total	Congestion Expected	No Congestion Expected	Total	Percent of Total
Late	Emergency	94	2,173	2,267	11.6%	101	1,934	2,035	12.7%
	Non Emergency	229	4,931	5,160	26.4%	262	4,306	4,568	28.6%
On Time	Emergency	6	29	35	0.2%	1	17	18	0.1%
	Non Emergency	1,191	10,884	12,075	61.8%	1,162	8,192	9,354	58.6%
Total		1,520	18,017	19,537	100.0%	1,526	14,449	15,975	100.0%

Once PJM processes an outage request, the outage request is labelled as Submitted, Received, Denied, Approved, Cancelled by Company, PJM Admin Closure, Revised, Active or Complete according to the processed stage of a request.[209] Table 12-69 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 12-69. Table 12-69 shows that of all the outage requests that were expected to cause congestion, 4.8 percent (74 out of 1,526) were denied by PJM in the first 10 months of the 2024/2025 planning period, 65.1 percent were complete and 20.3 percent (310 out of 1,526) were cancelled. Of all the outage requests that were expected to cause congestion, 4.1 percent (62 out of 1,520) were denied by PJM in the 2023/2024 planning period, 69.8 percent were complete and 17.9 percent (272 out of 1,520) were cancelled.

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

Table 12-69 Transmission facility outage requests by processed status[210]: June 2023 through March 2025

Received Status		2023/2024 (12 months) Cancelled	Complete	In Process	Denied	Congestion Expected	Percent Complete	2024/2025 (10 months) Cancelled	Complete	In Process	Denied	Congestion Expected	Percent Complete
Late	Emergency	2	88	2	2	94	93.6%	11	85	4	1	101	84.2%
	Non Emergency	34	164	11	16	229	71.6%	50	176	17	19	262	67.2%
On Time	Emergency	1	4	0	0	6	66.7%	0	1	0	0	1	100.0%
	Non Emergency	235	811	85	44	1,191	68.1%	249	731	111	54	1,162	62.9%
Total		272	1,067	98	62	1,520	70.2%	310	993	132	74	1,526	65.1%

There are clear rules defined for assigning On Time or Late status for submitted outage requests in both the PJM tariff and PJM manuals.[211] The On Time or Late status affects the way in which PJM addresses the potential to exceed transmission limits. Table 12-69 shows that in the first 10 months of the 2024/2025 planning period, 262 nonemergency outage requests were submitted late and expected to cause congestion. The expected impact on congestion and the options for controlling that congestion is the basis for PJM's treatment of late outage requests.

The definition of this congestion analysis in the PJM manuals is about physical limits and not about economic congestion. PJM approves on time outages based solely on whether limits are exceeded and available controlling actions, without regard to the resulting level of economic congestion. The MMU recommends that PJM draft a definition of the congestion analysis required for transmission outage requests and associated triggers, including both the extent of overloaded facilities and the level of economic congestion, to include in PJM manuals after appropriate review with appropriate rules for on time and late outage requests.[212]

210 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.

211 OA Schedule 1 § 1.9.2.

212 "PJM Manual 38: Operations Planning," Rev. 19 (Jan. 23, 2025). p 21. Manual 38 states: "The outages are analyzed for reliability and expected off-costs. Each outage is studied and any constraints (actual or facility/contingency pair) trending toward a limit or exceeding a limit is noted in eDART. The trending or exceeding of a limit in the study is referred to as potential "congestion". The limit may be any or a combination of thermal, voltage, or stability issues. If there is an expected constraint, PJM will mark the corresponding eDART ticket as "congestion expected". The "congestion expected" flag is used to indicate a potential issue that may occur in the Day-Ahead Market or in Real-time Operations. If there are non-cost controlling actions, changes to the generation pattern, or changes to system conditions, the noted congestion may not occur in the Day-Ahead Market or in Real-time Operations. For "On-time" outages, PJM ensures the constraint can be mitigated by applying both non-cost and off-cost operations. If there are no limit exceedances as a result, the outage will be approved. For "Late" outages, PJM will apply only non-cost operations."

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 economic impact. 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.

Rescheduling Transmission Facility Outage Requests

A TO can reschedule or cancel an outage after initial submission. Table 12-70 is a summary of all the outage requests planned for the 2023/2024 planning period and the first 10 months of the 2024/2025 planning period which were approved and then cancelled or rescheduled by TOs at least once. If an outage request was submitted, approved and subsequently rescheduled at least once, the outage request will be counted as Approved and Rescheduled. If an outage request was submitted, approved and subsequently cancelled at least once, the outage request will be counted as Approved and Cancelled. In the first 10 months of the 2024/2025 planning period, 28.4 percent of transmission outage requests were approved by PJM and then rescheduled by the TOs, and 12.0 percent of the transmission outages were approved by PJM and subsequently cancelled by the TOs. In the 2023/2024 planning period, 29.3

percent of transmission outage requests were approved by PJM and then rescheduled by the TO, and 12.2 percent of the transmission outages were approved by PJM and subsequently cancelled by the TO.[213]

Table 12-70 Rescheduled and cancelled transmission outage requests: June 2023 through March 2025

	2023/2024 (12 months)					2024/2025 (10 months)				
Planned Duration (Days)	Outage Requests	Approved and Rescheduled	Percent Approved and Rescheduled	Approved and Cancelled	Percent Approved and Cancelled	Outage Requests	Approved and Rescheduled	Percent Approved and Rescheduled	Approved and Cancelled	Percent Approved and Cancelled
<=5	14,916	3,037	20.4%	2,100	14.1%	11,810	2,342	19.8%	1,656	14.0%
>5 & <=30	2,903	1,623	55.9%	207	7.1%	2,525	1,330	52.7%	188	7.4%
>30	1,718	1,122	65.3%	90	5.2%	1,640	867	52.9%	72	4.4%
Total	19,537	5,782	29.6%	2,397	12.3%	15,975	4,539	28.4%	1,916	12.0%

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

A transmission outage ticket with duration of five days or less with an On Time status can retain its On Time status if the outage is rescheduled within the original scheduled month.[214] 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.[215] 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, create options for late requests based on the reasons, and apply the modified rules for late submissions to any such outages. The MMU recommends that PJM create options for treatment of late outages. The current rules apply more stringent rules, based on controlling actions, to late outages without distinguishing among reasons for late outages.

Long Duration Transmission Facility Outage Requests

PJM rules (Table 12-64) 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.

213 The number of tickets in each category can change over time. For example, a ticket initially classified as canceled or denied may be resubmitted at a later date for a different date range. Once approved the resubmitted ticket overrides the original ticket dates and details.
214 PJM, "Manual 3: Transmission Operations," Rev. 67 (Nov. 21, 2024).
215 *Id.*

More than one outage request can be submitted for the same transmission equipment. In order to accurately present the results, Table 12-71 shows equipment outages by the equipment instead of by outage request.

Table 12-71 shows that there were 10,757 transmission equipment planned outages in the first 10 months of the 2024/2025 planning period, of which 1,415 or 13.2 percent were longer than 30 days, and of which 179 or 1.7 percent were scheduled longer than 30 days when the duration of all the outage requests are combined for the same equipment.

Table 12-71 Transmission equipment outages: June 2023 through March 2025

		2023/2024 (12 months)		2024/2025 (10 months)	
Planned Duration (Days)	Divided into Shorter Periods	Count of Equipment with Planned Outages	Percent of Total	Count of Equipment with Planned Outages	Percent of Total
> 30	No	1,493	11.9%	1,415	13.2%
	Yes	262	2.1%	179	1.7%
<= 30		10,752	86.0%	9,163	85.2%
Total		12,507	100.0%	10,757	100.0%

Table 12-72 shows the details of long duration (> 30 days) outages when combining the duration of the outage requests for the same equipment.[216] The actual duration of scheduled outages would be longer than 30 days if the duration of the outage requests was appropriately combined for the same equipment. An effective duration was calculated for each piece of equipment by subtracting the start date of the earliest outage request from the end date of the latest outage request of the equipment. In the first 10 months of the 2024/2025 planning period, within effective duration greater than a month and shorter than two months, there were 35 outages with a combined duration longer than 30 days.[217]

Table 12-72 Transmission equipment outages by effective duration: June 2023 through March 2025

	2023/2024 (12 months)		2024/2025 (10 months)	
Effective Duration of Outage	Count of Equipment with Planned Outages	Percent of Total	Count of Equipment with Planned Outages	Percent of Total
<=31	6	2.3%	4	2.2%
>31 & <=62	34	13.0%	35	19.6%
>62 & <=93	19	7.3%	15	8.4%
>93	203	77.5%	125	69.8%
Total	262	100.0%	179	100.0%

216 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.
217 The length of a planned equipment outage can be modified by editing an existing ticket for the equipment outage or by adding new equipment outage tickets for the same equipment.

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.[218]

In the first 10 months of the 2024/2025 planning period, 411 outage requests were included in the annual FTR market outage list and 15,564 outage requests were not included.[219] In the 2023/2024 planning period, 393 outage requests were included in the annual FTR market outage list and 19,142 outage requests were not included. Table 12-73, Table 12-74, Table 12-75 and Table 12-76 show the summary information on the modeled outage requests and Table 12-77 and Table 12-78 show the summary information on outages that were not included in the Annual FTR Market.

Table 12-73 shows that 24.1 percent of the outage requests modeled in the Annual FTR Market for the first 10 months of the 2024/2025 planning period had a planned duration of less than two weeks and that 18.2 percent of the outage requests (75 out of 411) modeled in the Annual FTR Market for the planning period were submitted late according to outage submission rules. It also shows that 29.3 percent of the outage requests modeled in the Annual FTR Market for the 2023/2024 planning period had a planned duration of less than two weeks and that 17.0 percent of the outage requests (67 out of 393) modeled in the Annual FTR Market for the planning period were submitted late according to outage submission rules.

218 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.

219 PJM's treatment of transmission outages in the FTR models is discussed in the *2024 Annual State of the Market Report for PJM*, Section 13: FTRs and ARRs, Supply and Demand.

Table 12-73 Annual FTR market modeled transmission facility outage requests by received status: June 2023 through March 2025

	2023/2024 (12 months)				2024/2025 (10 months)			
Planned Duration	On Time	Late	Total	Percent of Total	On Time	Late	Total	Percent of Total
<2 weeks	100	15	115	29.3%	91	8	99	24.1%
>=2 weeks & <2 months	102	19	121	30.8%	127	19	146	35.5%
>=2 months	124	33	157	39.9%	118	48	166	40.4%
Total	326	67	393	100.0%	336	75	411	100.0%

Table 12-74 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 10 months of the 2024/2025 planning period were emergency outages. Four of the modeled outages expected to occur in the 2023/2024 planning period were emergency outages.

Table 12-74 Annual FTR market modeled transmission facility outage requests by emergency: June 2023 through March 2025

		2023/2024 (12 months)				2024/2025 (10 months)			
Received Status	Planned Duration	Emergency	Non Emergency	Total	Percent Non Emergency	Emergency	Non Emergency	Total	Percent Non Emergency
On Time	<2 weeks	0	100	100	100.0%	0	91	91	100.0%
	>=2 weeks & <2 months	0	102	102	100.0%	1	126	127	99.2%
	>=2 months	1	123	124	99.2%	0	118	118	100.0%
	Total	1	325	326	99.7%	1	335	336	99.7%
Late	<2 weeks	1	14	15	93.3%	0	8	8	100.0%
	>=2 weeks & <2 months	0	19	19	100.0%	0	19	19	100.0%
	>=2 months	3	30	33	90.9%	3	45	48	93.8%
	Total	4	63	67	94.0%	3	72	75	96.0%

PJM determines expected congestion for both On Time and Late outage requests. A Late outage request may be denied or cancelled if it is expected to cause congestion. Table 12-75 shows a summary of requests by expected congestion and received status. Of all the annual FTR market modeled outages expected to occur in the first 10 months of the 2024/2025 planning period and submitted late, 18.7 percent (14 out of 75) were expected to cause congestion. Of all the annual FTR market modeled outages expected to occur in the 2023/2024 planning period and submitted late, 14.9 percent (10 out of 67) were expected to cause congestion.

Table 12-75 Annual FTR market modeled transmission facility outage requests by congestion: June 2023 through March 2025

		2023/2024 (12 months)				2024/2025 (10 months)			
Received Status	Planned Duration	Congestion Expected	No Congestion Expected	Total	Percent Congestion Expected	Congestion Expected	No Congestion Expected	Total	Percent Congestion Expected
On Time	<2 weeks	27	73	100	27.0%	23	68	91	25.3%
	>=2 weeks & <2 months	27	75	102	26.5%	30	97	127	23.6%
	>=2 months	27	97	124	21.8%	26	92	118	22.0%
	Total	81	245	326	24.8%	79	257	336	23.5%
Late	<2 weeks	2	13	15	13.3%	2	6	8	25.0%
	>=2 weeks & <2 months	5	14	19	26.3%	4	15	19	21.1%
	>=2 months	3	30	33	9.1%	8	40	48	16.7%
	Total	10	57	67	14.9%	14	61	75	18.7%

Table 12-76 shows that 21.2 percent of outage requests modeled in the annual FTR market for the first 10 months of the 2024/2025 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 24.0 percent for the 2023/2024 planning period. Table 12-76 also shows that 18.7 percent of outages requests modeled in the Annual FTR Market for the first 10 months of the 2024/2025 planning period and with a duration of two months or longer were cancelled, compared to 22.3 percent for the 2023/2024 planning period.

Table 12-76 Annual FTR market modeled transmission facility outage requests by processed status: June 2023 through March 2025

		2023/2024 (12 months)		2024/2025 (10 months)	
Planned Duration	Processed Status	Outage Requests	Percent	Outage Requests	Percent
<2 weeks	In Progress	9	7.8%	9	9.1%
	Denied	0	0.0%	1	1.0%
	Approved	0	0.0%	2	2.0%
	Cancelled	26	22.6%	25	25.3%
	Revised	0	0.0%	1	1.0%
	Active	0	0.0%	1	1.0%
	Completed	80	69.6%	60	60.6%
	Total	115	100.0%	99	100.0%
>=2 weeks & <2 months	In Progress	13	10.7%	28	19.2%
	Denied	0	0.0%	0	0.0%
	Approved	1	0.8%	5	3.4%
	Cancelled	29	24.0%	31	21.2%
	Revised	0	0.0%	0	0.0%
	Active	0	0.0%	7	4.8%
	Completed	78	64.5%	75	51.4%
	Total	121	100.0%	146	100.0%
>=2 months	In Progress	22	14.0%	22	13.3%
	Denied	0	0.0%	3	1.8%
	Approved	1	0.6%	1	0.6%
	Cancelled	35	22.3%	31	18.7%
	Revised	0	0.0%	0	0.0%
	Active	8	5.1%	39	23.5%
	Completed	91	58.0%	70	42.2%
	Total	157	100.0%	166	100.0%
Total Cancelled		27	33.8%	33	49.3%
Grand Total		80		67	

More outage requests were not modeled in the Annual FTR Market than were modeled in the Annual FTR Market. In the first 10 months of the 2024/2025 planning period, 411 outage requests were modeled and 15,564 outage requests were not modeled in the Annual FTR Market. In the 2023/2024 planning period, 393 outage requests were modeled and 19,144 outage requests were not modeled in the Annual FTR Market.

Table 12-77 shows that 14.8 percent of outage requests not modeled in the Annual FTR Auction with duration longer than or equal to two months, labeled On Time according to the rules, were submitted or rescheduled after the Annual FTR Auction bidding opening date in the first seven months of the 2024/2025 planning period compared to 15.9 percent in the 2023/2024 planning period.

Table 12-77 Transmission facility outage requests not modeled in Annual FTR Auction: June 2023 through March 2025

	2023/2024 (12 months)						2024/2025 (10 months)					
	On Time			Late			On Time			Late		
Planned Duration	Before Bidding Opening Date	After Bidding Opening Date	Percent After	Before Bidding Opening Date	After Bidding Opening Date	Percent After	Before Bidding Opening Date	After Bidding Opening Date	Percent After	Before Bidding Opening Date	After Bidding Opening Date	Percent After
<2 weeks	1,796	8,700	82.9%	216	5,592	96.3%	1,773	6,188	77.7%	185	4,911	96.4%
>=2 weeks & <2 months	660	401	37.8%	142	763	84.3%	616	239	28.0%	145	700	82.8%
>=2 months	191	36	15.9%	268	379	58.6%	185	35	15.9%	246	341	58.1%
Total	2,647	9,137	77.5%	626	6,734	91.5%	2,574	6,462	71.5%	576	5,952	91.2%

Table 12-78 shows that 91.2 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 10 months of the 2024/2025 planning period. It also shows that 85.5 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 2023/2024 planning period.

Table 12-78 Late transmission facility outage requests: June 2023 through March 2025

	2023/2024 (12 months)			2024/2025 (10 months)		
Planned Duration	Completed Outages	Total	Percent Complete	Completed Outages	Total	Percent Complete
<2 weeks	4,861	5,592	86.9%	4,145	4,911	84.4%
>=2 weeks & <2 months	630	763	82.6%	579	700	82.7%
>=2 months	324	379	85.5%	311	341	91.2%
Total	5,815	6,734	86.4%	5,035	5,952	84.6%

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 create options for late requests based on the reasons, and modify the rules to reduce or eliminate the approval of late outage requests submitted or rescheduled after the FTR auction opening date, based on those options.

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.[220] Table 12-79 and Table 12-80 show the summary information on outage requests modeled in the Monthly Balance of Planning Period FTR Auction and Table 12-81 and Table 12-82 show the summary information on

220 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).

outage requests not modeled in the Monthly Balance of Planning Period FTR Auction.

Table 12-79 shows that on average, 28.8 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 10 months of the 2024/2025 planning period. On average, 27.9 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 2023/2024 planning period.

Table 12-79 Monthly Balance of Planning Period FTR Auction modeled transmission facility outage requests by received status: June 2023 through March 2025

	2023/2024				2024/2025			
Month	On Time	Late	Total	Percent Late	On Time	Late	Total	Percent Late
Jun	244	106	350	30.3%	272	134	406	33.0%
Jul	129	83	212	39.2%	154	100	254	39.4%
Aug	148	71	219	32.4%	211	101	312	32.4%
Sep	440	117	557	21.0%	488	175	663	26.4%
Oct	620	165	785	21.0%	542	190	732	26.0%
Nov	481	170	651	26.1%	511	197	708	27.8%
Dec	423	155	578	26.8%	359	127	486	26.1%
Jan	231	76	307	24.8%	239	80	319	25.1%
Feb	253	117	370	31.6%	275	103	378	27.2%
Mar	406	139	545	25.5%	477	158	635	24.9%
Apr	518	183	701	26.1%				
May	440	187	627	29.8%				
Average	361	131	492	27.9%	353	137	489	28.8%

Table 12-80 shows that on average, 20.4 percent of outage requests modeled in the Monthly Balance of Planning Period FTR Auction were cancelled in the first 10 months of the 2024/2025 planning period. On average, 19.1 percent of outage requests modeled in the Monthly Balance of Planning Period FTR Auction were cancelled in the 2023/2024 planning period.

Table 12-80 Monthly Balance of Planning Period FTR Auction modeled transmission facility outage requests by processed status: June 2023 through March 2025

Planning Year	Month	In Process	Denied	Approved	Cancelled	Revised	Active	Complete	Total	Percent Cancelled
2023/2024	Jun	21	1	10	59	0	71	188	350	16.9%
	Jul	23	7	14	38	1	57	72	212	17.9%
	Aug	16	4	12	43	0	62	82	219	19.6%
	Sep	60	8	12	107	1	175	194	557	19.2%
	Oct	71	3	17	168	0	214	312	785	21.4%
	Nov	58	6	15	119	0	199	254	651	18.3%
	Dec	57	6	16	111	1	90	297	578	19.2%
	Jan	40	8	13	56	2	93	95	307	18.2%
	Feb	42	0	9	60	0	117	142	370	16.2%
	Mar	56	4	11	102	0	142	230	545	18.7%
	Apr	74	10	23	143	0	167	284	701	20.4%
	May	52	7	19	120	2	136	291	627	19.1%
	Average	48	5	14	94	1	127	203	492	19.1%
2024/2025	Jun	28	13	16	93	0	90	166	406	22.9%
	Jul	22	8	15	41	0	97	71	254	16.1%
	Aug	18	16	10	68	0	81	119	312	21.8%
	Sep	70	7	30	111	0	192	253	663	16.7%
	Oct	60	1	19	174	2	209	267	732	23.8%
	Nov	63	5	23	124	0	185	308	708	17.5%
	Dec	40	16	8	101	0	101	220	486	20.8%
	Jan	41	9	9	67	0	110	83	319	21.0%
	Feb	27	6	11	79	0	116	139	378	20.9%
	Mar	62	5	19	139	1	164	245	635	21.9%
	Average	43	9	16	100	0	135	187	489	20.4%

Table 12-81 shows that on average, 13.6 percent of outage requests not modeled in the Monthly Balance of Planning Period FTR Auction, labeled On Time according to the rules, were submitted after the monthly FTR auction bidding opening dates in the first 10 months of the 2024/2025 planning period, compared to 10.6 percent in the 2023/2024 planning period. On average, 56.8 percent of outage requests not modeled in the Monthly Balance of Planning Period FTR Auction, labeled Late according to the rules, were submitted after the Monthly Balance of Planning Period FTR Auction bidding opening dates in the first 10 months of the 2024/2025 planning period, compared to 57.8 percent in the 2023/2024 planning period.

Table 12-81 Transmission facility outage requests not modeled in Monthly Balance of Planning Period FTR Auction: June 2023 through March 2025

	2023/2024						2024/2025					
	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	765	65	7.8%	431	463	51.8%	684	151	18.1%	370	572	60.7%
Jul	363	62	14.6%	295	467	61.3%	438	152	25.8%	305	540	63.9%
Aug	401	61	13.2%	324	498	60.6%	455	105	18.8%	296	482	62.0%
Sep	856	89	9.4%	361	479	57.0%	985	103	9.5%	337	528	61.0%
Oct	1,073	90	7.7%	385	645	62.6%	1,120	124	10.0%	413	732	63.9%
Nov	931	89	8.7%	398	496	55.5%	722	76	9.5%	444	529	54.4%
Dec	675	74	9.9%	363	474	56.6%	604	115	16.0%	428	487	53.2%
Jan	675	116	14.7%	321	476	59.7%	1,115	129	10.4%	1,287	541	29.6%
Feb	756	87	10.3%	357	417	53.9%	643	84	11.6%	416	524	55.7%
Mar	1,230	131	9.6%	375	498	57.0%	1,272	89	6.5%	446	772	63.4%
Apr	1,366	167	10.9%	424	593	58.3%						
May	1,285	141	9.9%	445	650	59.4%						
Average	865	98	10.6%	373	513	57.8%	804	113	13.6%	474	571	56.8%

Table 12-82 shows that on average, 67.1 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 10 months of the 2024/2025 planning period, compared to 68.5 percent in the 2023/2024 planning period.

Table 12-82 Late transmission facility outage requests: June 2023 through March 2025

	2023/2024			2024/2025		
	Completed Outages	Total	Percent Complete	Completed Outages	Total	Percent Complete
Jun	324	463	70.0%	367	572	64.2%
Jul	329	467	70.4%	380	540	70.4%
Aug	350	498	70.3%	359	482	74.5%
Sep	340	479	71.0%	360	528	68.2%
Oct	415	645	64.3%	472	732	64.5%
Nov	310	496	62.5%	367	529	69.4%
Dec	332	474	70.0%	324	487	66.5%
Jan	309	476	64.9%	348	541	64.3%
Feb	285	417	68.3%	341	524	65.1%
Mar	350	498	70.3%	496	772	64.2%
Apr	390	593	65.8%			
May	482	650	74.2%			
Average	351	513	68.5%	381	571	67.1%

Table 12-82 shows that only 2.6 percent of all outage requests were modeled in the Annual FTR Auction in the first 10 months of the 2024/2025 planning period, and 2.0 percent were modeled in the 2023/2024 planning period. For Monthly FTR Auctions in the first 10 months of the 2024/2025 planning period, an average of 25.3 percent of all outage requests were modeled, and 25.7 percent were modeled in the 2023/2024 planning period.

Table 12-83 FTR market modeled transmission facility outage requests: June 2023 through March 2025

	2023/2024 (12 months)			2024/2025 (10 months)		
Planned Duration	Annual Modeled	Monthly Modeled	Total	Annual Modeled	Monthly Modeled	Total
<2 weeks	115	3,106	3,221	99	2,466	2,565
>=2 weeks & <2 months	121	1,342	1,463	146	1,019	1,165
>=2 months	157	577	734	166	559	725
Total	393	5,025	5,418	411	4,044	4,455
All outage requests			19,537			15,975
Percent of Modeled	2.0%	25.7%	27.7%	2.6%	25.3%	27.9%

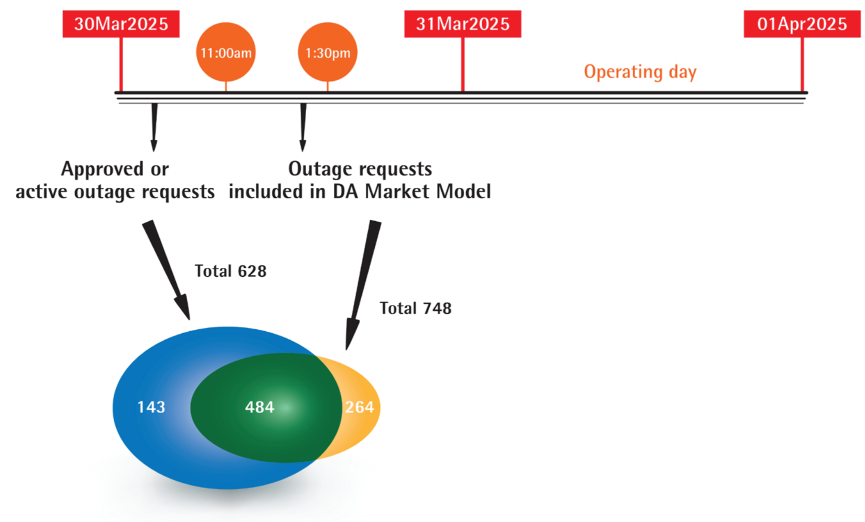
Transmission Facility Outage Analysis in the Day-Ahead Energy Market

Transmission facility outages also affect the energy market. Just as with the FTR market, it is critical that outages that affect the operating day are known prior to the submission of offers in the day-ahead energy market so that market participants can understand market conditions and PJM can accurately model market conditions in the day-ahead market. PJM requires transmission owners to submit changes to outages scheduled for the next two days no later than 09:30 am. [221]

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 in eDART. 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 March 31, 2025, Figure 12-7 shows that: there were 628 approved or active outages seen by market participants before the day-ahead market was closed; there were 748 outage requests included in the day-ahead market model; there were 484 outage requests included in both sets of outage; there were 143 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 264 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: March 31, 2025



221 PJM, "Manual 3: Transmission Operations," Rev. 67 (Nov. 21, 2024).

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.[222] Figure 12-8 shows that the number of outages visible to market participants but excluded in the day-ahead model has decreased significantly for the 2023/2024 and 2024/2025 planning periods.

Figure 12-8 Approved or active outage requests: January 2015 through March 2025

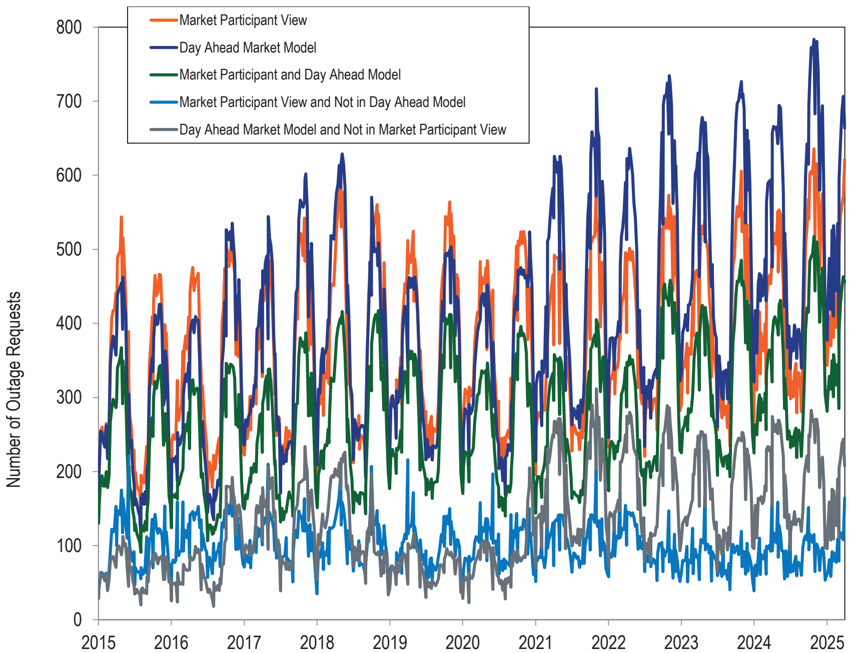


Figure 12-9 compares the weekly average number of outages included in the day-ahead market with the outages that actually occurred during the operating day. Figure 12-9 shows that beginning in 2021, the weekly average number of outages included in the day-ahead market (dark blue line) was higher in the spring and fall than previous years, but many of these outages did not actually occur in the real time market (gray line).

Figure 12-9 Day-ahead market model outages: January 2015 through March 2025

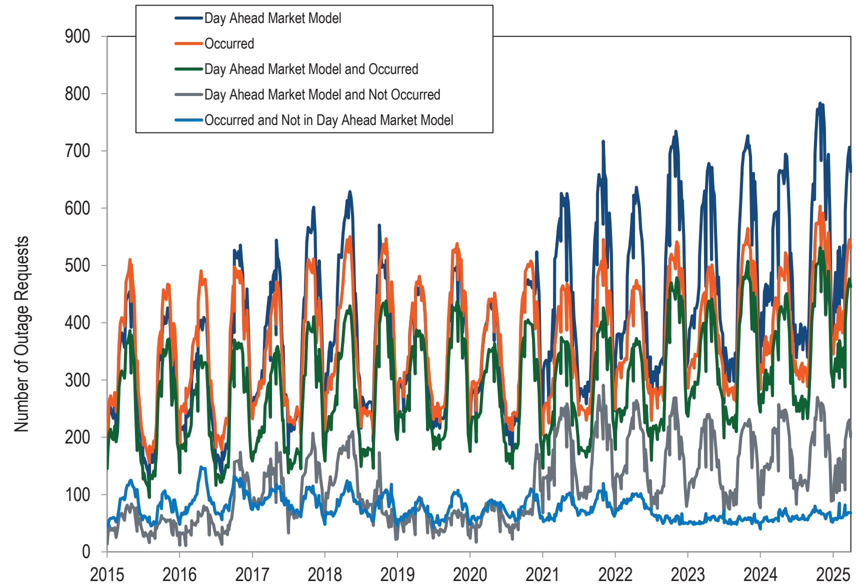


Figure 12-10 compares the weekly average number of active or approved outages for which information was visible to market participants through eDART prior to the close of the day-ahead market with the outages that actually occurred in the real time market during the operating day. Figure 12-10 shows the number of outages visible to market participants in eDART, but not actually occurring in the real time market, varies from less than 10 to over 100 in any given week.

222 The analysis and figures in this report (Figure 12-8, Figure 12-9, and Figure 12-10) that compare the number of outages modeled in the day-ahead market, the number of outages that are made visible to market participants through eDART, and the number of outages that actually occurred in the real time market are based on a revised method (relative to the method used in prior State of the Market Reports) that correctly accounts for outages that did not, at the time the outage was active, have an end date specified on the outage ticket.

Figure 12-10 Approved or active outage requests: January 2015 through March 2025

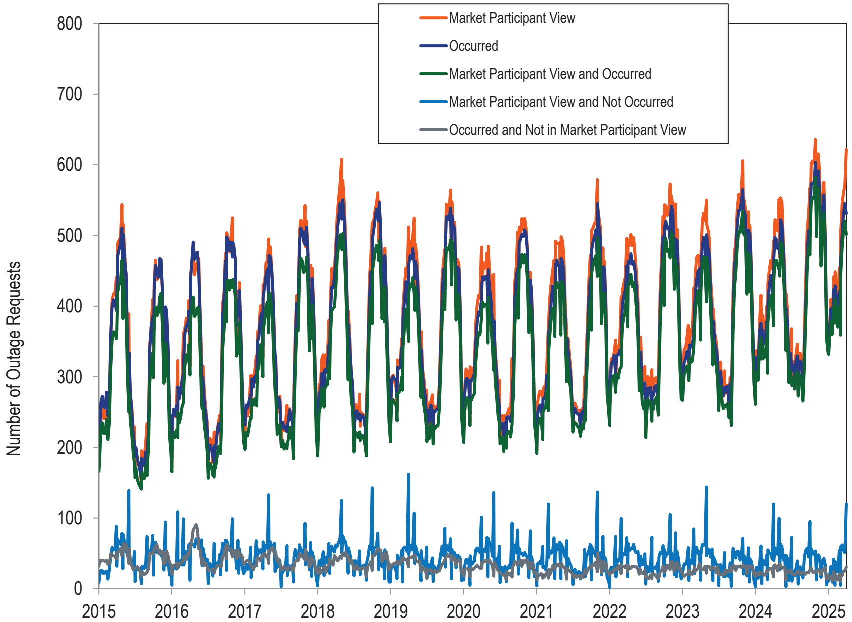


Figure 12-8, Figure 12-9, and Figure 12-10 show that on a weekly average basis, for the full years 2023, 2024, and the first three months of 2025, the active or approved outages for which information was visible to day-ahead market participants, the outages included as inputs in the day-ahead market model and the outages that actually occurred in real time are not consistent.