Generation and Transmission Planning[1]

Overview

Generation Interconnection Planning

Existing Generation Mix

- As of June 30, 2023, PJM had a total installed capacity of 194,586.8 MW, of which 40,555.4 MW (20.8 percent) are coal fired steam units, 56,238.2 MW (28.9 percent) are combined cycle units and 33,452.6 MW (17.2 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 194,586.8 MW of installed capacity, 66,803.7 MW (34.3 percent) are from units older than 40 years, of which 30,868.3 MW (46.2 percent) are coal fired steam units, 191.0 MW (0.3 percent) are combined cycle units and 19,720.6 MW (29.5 percent) are nuclear units.

Generation Retirements[2]

- There are 56,155.6 MW of generation that have been, or are planned to be, retired between 2011 and 2026, of which 42,502.8 MW (75.7 percent) are coal fired steam units.
- In the first six months of 2023, 3,691.8 MW of generation retired. The largest generator that retired in the first six months of 2023 was the 800.0 MW Yorktown 3 oil fired steam unit located in the DOM Zone. Of the 3,691.8 MW of generation that retired, 1,827.0 MW (49.5 percent) were located in the DOM Zone.
- As of June 30, 2023, there are 4,973.1 MW of generation that have requested retirement after June 30, 2023, of which 1,884.0 MW (37.9 percent) are located in the PE Zone. Of the generation requesting retirement in the PE Zone, 1,884.0 MW (100.0 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 June 30, 2023) <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 June 30, 2023, 287,084.8 MW were in generation request queues in the status of active, under construction or suspended, a decrease of 407.9 MW (0.1 percent) from the 287,492.7 MW the end of 2022.[6] Based on historical completion rates, 42,040.5 MW (14.6 percent) of new generation in the queue are expected to go into service. In the first six months of 2023, the AI2 queue window closed, and the AJ1 window opened. As projects move through the queue process, projects can be removed from the queue due to incomplete or invalid data, withdrawn by the market participant or placed in service.
- As of June 30, 2023, 8,165 projects, representing 827,797.5 MW, have entered the queue process since its inception in 1998. Of those, 1,101 projects, representing 85,750.0 MW, went into service. Of the projects that entered the queue process, 3,543 projects, representing 454,962.8 MW (55.0 percent of the MW) withdrew prior to completion. Such projects may create barriers to entry for projects that would otherwise be completed, by taking up queue positions, increasing interconnection costs and creating uncertainty.
- In the first six months of 2023, 2,253.9 MW from the queue went in service. Of the 2,253.9 MW that went in service, 1,449.0 MW (64.3 percent) were combined cycle units, 468.1 MW (20.8 percent) were combustion turbine

3 See PJM. Planning. "New Services Queue," (Accessed on June 30, 2023) <https://www.pjm.com/planning/service-requests/services-request-status>.
4 181 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 The queue totals in this report are the winter net MW energy for the interconnection requests ("MW Energy") as shown in the queue.

natural gas units, 200 MW (8.6 percent) were wind units and 136.8 MW (6.1 percent) were solar units.

- The number of queue entries increased during the past several years, primarily renewable projects. Of the 5,513 projects entered from January 2015 through June 2023, 4,149 projects (75.3 percent) were renewable. Of the 444 projects entered in the first six months of 2023, 399 projects (89.9 percent) were renewable. Renewable projects make up 77.6 percent of all projects in the queue and those projects account for 75.6 percent of the nameplate MW currently active, suspended or under construction in the queue as of June 30, 2023.

  Of the 217,146.5 MW of renewable projects in the queue, only 14,422.9 MW (6.6 percent) of capacity resources are expected to go into service, based on both historical completion rates and ELCC derate factors for battery, wind and solar.

Regional Transmission Expansion Plan (RTEP)

Market Efficiency Process

- There are significant issues with PJM's cost/benefit analysis that should be addressed prior to approval of additional projects. PJM's cost/benefit analysis does not correctly account for the costs of increased congestion associated with market efficiency projects.
- Through June 30, 2023, PJM has completed five market efficiency cycles under Order No. 1000.[7]

PJM MISO Interregional Market Efficiency Process (IMEP)

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

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

PJM MISO Targeted Market Efficiency Process (TMEP)

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

Supplemental Transmission Projects

- Supplemental projects are defined to be "transmission expansions or enhancements that are not required for compliance with PJM criteria and are not state public policy projects according to the PJM Operating Agreement. These projects are used as inputs to RTEP models, but are not required for reliability, economic efficiency or operational performance criteria, as determined by PJM."[8] Supplemental projects are exempt from competition.
- The average number of supplemental projects in each expected in service year increased by 955.0 percent, from 20 for years 1998 through 2007 (pre Order No. 890) to 211 for years 2008 through 2023 (post Order 890).[9]

End of Life Transmission Projects

- An end of life transmission project is a project submitted for the purpose of replacing existing infrastructure that is at, or is approaching, the end of its useful life. End of life transmission projects should be included in the RTEP process and should be subject to a transparent, robust and clearly defined mechanism to permit competition to build the project. Under the current approach, end of life projects are excluded from the RTEP process and exempt from competition.

7 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).

8 See PJM. "Transmission Construction Status," (Accessed on June 30, 2023) <https://www.pjm.com/planning/project-construction>.

9 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).

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.[10] In the first six months of 2023, the PJM Board approved $559.3 million in upgrades. As of June 30, 2023, the PJM Board has approved $42.1 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 June 30, 2023, 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.[11]
- There were 19,714 transmission outage requests submitted in the 2022/2023 planning period. Of the requested outages, 77.5 percent were planned for less than or equal to five days and 8.2 percent were planned for greater than 30 days. Of the requested outages, 37.5 percent were late according to the rules in PJM's Manual 3.

Recommendations

Generation Retirements

- The MMU recommends that the question of whether Capacity Interconnection Rights (CIRs) should persist after the retirement of a unit be addressed. The rules need to ensure that incumbents cannot exploit control of CIRs to block or postpone entry of competitors.[12] (Priority: 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. (Priority: High. First reported Q1 2023. Not adopted.)

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

11 See "PJM Manual 03: Transmission Operations," Rev. 64 (May 31, 2023).

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

- The MMU recommends that barriers to entry be addressed in a timely manner in order to help ensure that the capacity market will result in the entry of new capacity to meet the needs of PJM market participants. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends improvements in queue management including that PJM establish a review process to ensure that projects are removed from the queue if they are not viable, as well as a process to allow commercially viable projects to advance in the queue ahead of projects which have failed to make progress, subject to rules to prevent gaming.[13] (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.[14] (Priority: Medium. First reported 2014. Status: Partially adopted.)
- The MMU recommends outsourcing interconnection studies to an independent party to avoid potential conflicts of interest. Currently, these studies are performed by incumbent transmission owners under PJM's direction. This creates potential conflicts of interest, particularly when transmission owners are vertically integrated and the owner of transmission also owns generation. (Priority: Low. First reported 2013. Status: Not adopted.)

Market Efficiency Process

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

Comparative Cost Framework

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

Transmission Competition

- The MMU recommends, to increase the role of competition, that the exemption of supplemental projects from the Order No. 1000 competitive process be terminated and that the basis for all such exemptions be reviewed and modified to ensure that the supplemental project designation is not used to exempt transmission projects from a transparent, robust and clearly defined mechanism to permit competition to build such projects or to effectively replace the RTEP process. (Priority: Medium. First reported 2017. Status: Not adopted. Rejected by FERC.)[15]
- The MMU recommends, to increase the role of competition, that the exemption of end of life projects from the Order No. 1000 competitive process be terminated and that end of life transmission projects be included in the RTEP process and should be subject to a transparent, robust and clearly defined mechanism to permit competition to build such projects. (Priority: Medium. First reported 2019. Status: Not adopted. Rejected by FERC.)[16]

13 PJM Filing, FERC Docket No. ER22-2110-000 (June 14, 2022); 181 FERC ¶ 61,162 (2022).
14 Ibid.
15 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).
16 In recent decisions addressing competing proposals on end of life projects, the Commission accepted a transmission owner proposal excluding end of life projects from competition in the RTEP process, 172 FERC ¶ 61,136 (2020), *reh'g denied*, 173 FERC ¶ 61,225 (2020), and rejected a proposal from PJM stakeholders that would have included end of life projects in competition in the RTEP process, 173 FERC ¶ 61,242 (2020).

- The MMU recommends that PJM enhance the transparency and queue management process for nonincumbent transmission investment. Issues related to data access and complete explanations of cost impacts should be addressed. The goal should be to remove barriers to competition from nonincumbent transmission providers. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM continue to incorporate the principle that the goal of transmission planning should be the incorporation of transmission investment decisions into market driven processes as much as possible. (Priority: Low. First reported 2001. Status: Not adopted.)
- The MMU recommends the creation of a mechanism to permit a direct comparison, or competition, between transmission and generation alternatives, including which alternative is less costly and who bears the risks associated with each alternative. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM establish fair terms of access to rights of way and property, such as at substations, in order to remove any barriers to entry and permit competition between incumbent transmission providers and nonincumbent transmission providers in the RTEP. (Priority: Medium. First reported 2014. Status: Not adopted.)
- The MMU recommends that rules be implemented to permit competition to provide financing for transmission projects. This competition could reduce the cost of capital for transmission projects and significantly reduce total costs to customers. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that storage resources not be includable as transmission assets for any reason. (Priority: High. First reported 2020. Status: Not adopted.)

Cost Allocation

- The MMU recommends a comprehensive review of the ways in which the solution based dfax is implemented. The goal for such a process would be to ensure that the most rational and efficient approach to implementing the solution based dfax method is used in PJM. Such an approach should allocate costs consistent with benefits and appropriately calibrate the incentives for investment in new transmission capability. No replacement approach should be approved until all potential alternatives, including the status quo, are thoroughly reviewed. (Priority: Medium. First reported 2020. Status: Not adopted.)
- The MMU recommends changing the minimum distribution factor in the allocation from 0.01 to 0.00 and adding a threshold minimum usage impact on the line.[17] (Priority: Medium. First reported 2015. Status: Not adopted.)

Transmission Line Ratings

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

Transmission Facility Outages

- The MMU recommends that PJM reevaluate all transmission outage tickets as on time or late as if they were new requests when an outage is rescheduled, 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 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.)

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

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

The MMU recognizes that the Commission has issued orders that are inconsistent with the recommendations of the MMU and that PJM cannot unilaterally modify those directives. It remains the recommendation of the MMU that the PJM rules for competitive transmission development through the RTEP should build upon FERC Order No. 1000 to create real competition between incumbent transmission providers and nonincumbent transmission providers. The ability of transmission owners to block competition for supplemental projects and end of life projects and the reasons for that policy should be reevaluated. PJM should enhance the transparency and queue management process for nonincumbent transmission investment. Issues related to data access and complete explanations of cost impacts should be addressed. The goal should be to remove barriers to competition from nonincumbent transmission.

Another element of opening competition would be to consider transmission owners' ownership of property and rights of way at or around transmission substations. In many cases, the land acquired included property intended to support future expansion of the grid. Incumbents have included the costs of the property in their rate base, paid for by customers. PJM now has the responsibility for planning the development of the grid under its RTEP process. Property bought to facilitate future expansion should be a part of the RTEP process and be made available to all providers on equal terms.

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

Managing the generation queues is a complex process. The PJM queue evaluation process will be significantly improved, based on the proposal submitted by PJM on June 14, 2022, and approved by FERC on November 29, 2022.[18] [19] The new rules include significant modifications to the interconnection process designed to address some of the key underlying issues and significantly improve the efficiency of the process. These modifications include process efficiency enhancements, recognition of project clusters affecting the same transmission facilities, incentives to reduce the entry of speculative projects in the queue, and incentives to remove projects that are not expected to reach commercial operation. The proposed solution should help to reduce backlog and to remove projects that are not viable earlier to help improve the overall efficiency of the queue process.

18 See *PJM*, Docket No. ER22-2110 (June 14, 2022).
19 181 FERC ¶ 61,162 (2022).

The impact of the modifications to the queue process will need to be evaluated to determine if they successfully remove projects from the queue if they are not viable, and allow commercially viable projects to advance in the queue ahead of projects which have failed to make progress. The behavior of project developers also creates issues with queue management. When developers put multiple projects in the queue to maintain their own optionality while planning to build only one they also affect all the projects that follow them in the queue. Project developers may also enter speculative projects in the queue and then put the project in suspended status while they address financing. The impacts of such behavior and the incentives for such behavior are addressed in the new process which includes nonrefundable fees, credit requirements, enhanced site control, elimination of the ability to suspend a project and milestone requirements. The impact of these aspects of the revised interconnection process should continue to be evaluated to ensure that they are having the desired effect on project developer behavior. The PJM queue evaluation process should continue to be improved to help ensure that barriers to competition for new generation investments are not created. Issues that need to be addressed include the ownership rights to CIRs and whether transmission owners should perform interconnection studies.

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

The Commission should require PJM, for example, to enhance the transparency and queue management process for nonincumbent transmission investment. Issues related to data access and complete explanations of cost impacts should be addressed. The goal should be to remove barriers to competition from nonincumbent transmission.

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

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

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

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

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

There are currently no market incentives for transmission owners to plan, submit and complete transmission outages in a timely and efficient manner. Requiring transmission owners to pay does not create an effective incentive when those payments are passed through to transmission customers. The process for the submission of planned transmission outages needs to be carefully reviewed and redesigned to limit the ability of transmission owners to submit transmission outages that are late for FTR auction bid submission dates and are late for the day-ahead energy market and that have large and unnecessary impacts on the PJM energy market. The submission of late transmission outages can inappropriately affect market outcomes when market participants do not have the ability to modify market bids and offers. The PJM process for evaluating the congestion impact of transmission outages needs to be clearly defined and upgraded to provide for management of transmission outages to minimize market impacts. The MMU continues to recommend that PJM draft a clear 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.[20]

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.

20 PJM, "Manual 38: Operations Planning," Rev. 16 (Jan. 25, 2023), p20.

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.

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 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.

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.[21] This provision has been known as Reliability Must Run (RMR) service but RMR is not defined in the PJM tariff. Here the term Part V reliability service is used. 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 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.

Generation Interconnection Planning

Existing Generation Mix

Table 12-1 shows the existing PJM capacity by control zone and unit type.[22] As of June 30, 2023, PJM had an installed capacity of 194,586.8 MW, of which 40,555.4 MW (20.8 percent) are coal fired steam units, 56,238.2 MW (28.9 percent) are combined cycle units and 33,452.6 MW (17.2 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.

21 OATT Part V §114.
22 The unit type RICE refers to Reciprocating Internal Combustion Engines.

The AEP Zone has the most installed capacity of any PJM zone. Of the 194,586.8 MW of PJM installed capacity, 34,618.6 MW (17.8 percent) are in the AEP Zone, of which 13,463.0 MW (38.9 percent) are coal fired steam units, 9,294.0 MW (26.8 percent) are combined cycle units and 2,071.0 MW (6.0 percent) are nuclear units.

Table 12-1 Existing capacity: June 30, 2023 (By zone and unit type (MW))[23]

Zone	Battery	Combined Cycle	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
ACEC	0.0	781.6	544.7	0.0	0.0	1.6	0.0	0.0	0.0	0.0	4.0	4.0	69.7	0.0	0.0	0.0	0.0	0.0	0.0	7.5	0.0	1,413.0
AEP	4.0	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	911.2	0.0	0.0	13,463.0	738.0	0.0	0.0	3,500.9	0.0	34,618.6
AMPT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
APS	80.4	2,843.7	1,223.3	0.0	2.0	0.0	0.0	129.2	0.0	22.4	0.0	18.3	134.3	0.0	0.0	4,021.0	0.0	0.0	0.0	985.1	0.0	9,459.7
ATSI	0.0	4,647.5	958.0	608.0	6.4	0.0	0.0	0.0	2,134.0	0.0	5.5	5.6	0.0	0.0	0.0	0.0	325.0	0.0	136.0	0.0	0.0	8,826.0
BGE	1.0	0.0	267.6	228.8	0.0	0.0	0.0	0.0	1,716.0	0.0	0.0	4.2	1.1	0.0	0.0	1,578.0	143.5	397.0	57.0	0.0	0.0	4,394.2
COMED	109.0	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	9.0	0.0	0.0	2,646.0	1,036.0	0.0	0.0	5,231.0	0.0	31,430.1
DAY	0.0	0.0	897.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	34.0	0.0	36.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	967.6
DUKE	18.0	522.2	598.0	56.0	0.0	0.0	0.0	112.0	0.0	0.0	0.0	4.8	200.0	0.0	0.0	1,252.0	47.0	0.0	0.0	0.0	0.0	2,810.0
DUQ	0.0	306.0	0.0	15.0	0.0	0.0	0.0	6.3	1,777.0	14.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,118.7
DOM	0.0	9,138.0	3,835.3	256.4	10.0	0.0	3,003.0	586.3	3,581.3	0.0	18.0	106.4	3,374.5	0.0	0.0	2,473.2	55.0	0.0	368.4	587.0	0.0	27,392.8
DPL	0.0	1,742.5	978.2	478.2	0.0	30.0	0.0	0.0	0.0	0.0	88.0	14.1	412.2	0.0	0.0	410.0	710.0	153.0	70.0	0.0	0.0	5,086.2
EKPC	0.0	0.0	774.0	0.0	0.0	0.0	0.0	136.0	0.0	0.0	0.0	0.0	50.0	0.0	0.0	1,687.0	0.0	0.0	0.0	0.0	0.0	2,647.0
JCPLC	66.8	2,229.5	531.1	225.6	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	3,623.7
MEC	0.0	2,595.0	2.0	398.5	0.0	0.0	0.0	19.0	0.0	0.0	0.0	30.9	0.0	0.0	0.0	80.0	35.0	0.0	60.0	0.0	0.0	3,220.4
OVEC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,388.8	0.0	0.0	0.0	0.0	0.0	2,388.8
PECO	0.0	4,089.0	0.0	828.0	0.0	0.0	1,070.0	572.0	4,546.8	0.0	2.0	0.9	3.0	0.0	0.0	0.0	765.3	0.0	103.0	0.0	0.0	11,980.0
PE	28.4	1,900.0	350.5	57.0	0.0	0.0	513.0	77.8	0.0	120.1	28.0	11.0	53.5	0.0	0.0	6,053.5	610.0	0.0	42.0	1,100.4	0.0	10,945.2
PEPCO	0.0	1,736.5	764.2	258.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8.7	2.5	0.0	0.0	0.0	1,164.1	0.0	52.0	0.0	0.0	3,986.0
PPL	20.0	5,558.5	234.0	36.0	20.6	0.0	0.0	706.6	2,520.0	12.0	5.0	14.7	35.0	0.0	0.0	2,547.9	2,449.0	0.0	29.0	216.5	0.0	14,404.8
PSEG	7.7	4,223.1	958.2	0.0	0.0	0.0	0.0	5.0	3,493.0	0.0	0.0	9.0	230.3	0.0	0.0	0.0	3.0	0.0	179.1	0.0	0.0	9,108.3
XIC	0.0	0.0	670.6	0.0	0.0	0.0	0.0	0.0	1,140.0	0.0	0.0	0.0	0.0	0.0	0.0	1,955.0	0.0	0.0	0.0	0.0	0.0	3,765.6
Total	335.3	56,238.2	24,748.7	3,687.9	43.8	32.0	4,792.0	2,771.1	33,452.6	168.9	184.5	282.1	5,938.5	0.0	0.0	40,555.4	8,080.9	550.0	1,096.5	11,628.4	0.0	194,586.8

23 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 194,586.8 MW of installed capacity, 48,167.3 MW (24.8 percent) are in Pennsylvania, of which 8,681.4 MW (18.0 percent) are coal fired steam units, 18,292.2 MW (38.0 percent) are combined cycle units and 8,843.8 MW (18.4 percent) are nuclear units.

Table 12-2 Existing capacity: June 30, 2023 (By state and unit type (MW))

State	Battery	Combined Cycle	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
DC	0.0	19.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	19.5
DE	0.0	742.5	325.5	116.3	0.0	30.0	0.0	0.0	0.0	0.0	0.0	8.1	50.0	0.0	0.0	410.0	710.0	0.0	70.0	0.0	0.0	2,462.4
IL	109.0	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	9.0	0.0	0.0	2,646.0	1,036.0	0.0	0.0	5,231.0	0.0	31,430.1
IN	0.0	1,835.0	441.4	0.0	0.0	0.0	0.0	8.2	0.0	0.0	0.0	3.2	282.6	0.0	0.0	3,923.8	0.0	0.0	0.0	2,353.2	0.0	8,847.4
KY	0.0	0.0	1,618.1	0.0	0.0	0.0	0.0	136.0	0.0	0.0	0.0	0.0	50.0	0.0	0.0	1,687.0	278.0	0.0	0.0	0.0	0.0	3,769.1
MD	21.0	2,717.0	1,684.5	502.7	0.0	0.0	0.0	0.0	1,716.0	0.0	76.0	18.9	385.1	0.0	0.0	1,758.0	1,307.6	550.0	109.0	295.0	0.0	11,140.8
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	1,056.5	0.0	0.0	0.0	0.0	0.0	0.0	208.0	0.0	1,762.5
NJ	74.5	7,234.2	2,034.0	225.6	0.0	2.0	140.0	5.0	3,493.0	0.0	4.0	27.1	716.1	0.0	0.0	0.0	3.0	0.0	179.1	7.5	0.0	14,145.0
OH	22.0	10,634.7	4,201.2	680.2	6.4	0.0	0.0	200.0	2,134.0	0.0	34.0	10.4	660.1	0.0	0.0	6,820.0	47.0	0.0	136.0	1,147.7	0.0	26,733.7
PA	49.9	18,292.2	1,473.9	1,334.5	20.6	0.0	1,583.0	1,445.7	8,843.8	168.9	40.5	75.8	156.5	0.0	0.0	8,681.4	4,184.3	0.0	234.0	1,582.3	0.0	48,167.3
TN	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
VA	0.0	8,973.0	4,172.3	591.4	12.0	0.0	3,069.0	460.1	3,581.3	0.0	12.0	112.4	2,548.0	0.0	0.0	1,468.2	515.0	0.0	368.4	12.0	0.0	25,895.1
WV	58.9	0.0	1,073.9	11.0	0.0	0.0	0.0	189.3	0.0	0.0	0.0	8.0	20.0	0.0	0.0	11,206.0	0.0	0.0	0.0	791.7	0.0	13,358.8
XIC	0.0	0.0	670.6	0.0	0.0	0.0	0.0	0.0	1,140.0	0.0	0.0	0.0	0.0	0.0	0.0	1,955.0	0.0	0.0	0.0	0.0	0.0	3,765.6
Total	335.3	56,238.2	24,748.7	3,687.9	43.8	32.0	4,792.0	2,771.1	33,452.6	168.9	184.5	282.1	5,938.5	0.0	0.0	40,555.4	8,080.9	550.0	1,096.5	11,628.4	0.0	194,586.8

Table 12-3 and Figure 12-1 show the age of existing PJM generators, by unit type, as of June 30, 2023. Of the 194,586.8 MW of installed capacity, 66,803.7 MW (34.3 percent) are from units older than 40 years, of which 30,868.3 MW (46.2 percent) are coal fired steam units, 191.0 MW (0.3 percent) are combined cycle units and 19,720.6 MW (29.5 percent) are nuclear units.

Table 12-3 Capacity (MW) by unit type and age (years): June 30, 2023

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	335.3	42,450.2	2,964.7	0.0	43.8	32.0	0.0	293.6	0.0	156.9	6.0	184.9	5,938.5	0.0	0.0	3,475.0	82.0	0.0	47.4	11,538.4	0.0	67,548.6
20 to 40	0.0	13,597.0	21,332.3	903.0	0.0	0.0	3,003.0	318.4	13,732.0	12.0	18.0	97.2	0.0	0.0	0.0	6,212.1	76.3	0.0	843.1	90.0	0.0	60,234.4
40 to 60	0.0	191.0	451.7	2,784.9	0.0	0.0	1,789.0	232.0	19,720.6	0.0	160.5	0.0	0.0	0.0	0.0	28,166.5	6,173.1	550.0	0.0	0.0	0.0	60,219.3
Greater than 60	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,927.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,701.8	1,749.5	0.0	206.0	0.0	0.0	6,584.4
Total	335.3	56,238.2	24,748.7	3,687.9	43.8	32.0	4,792.0	2,771.1	33,452.6	168.9	184.5	282.1	5,938.5	0.0	0.0	40,555.4	8,080.9	550.0	1,096.5	11,628.4	0.0	194,586.8

Figure 12-1 Capacity (MW) by age (years): June 30, 2023

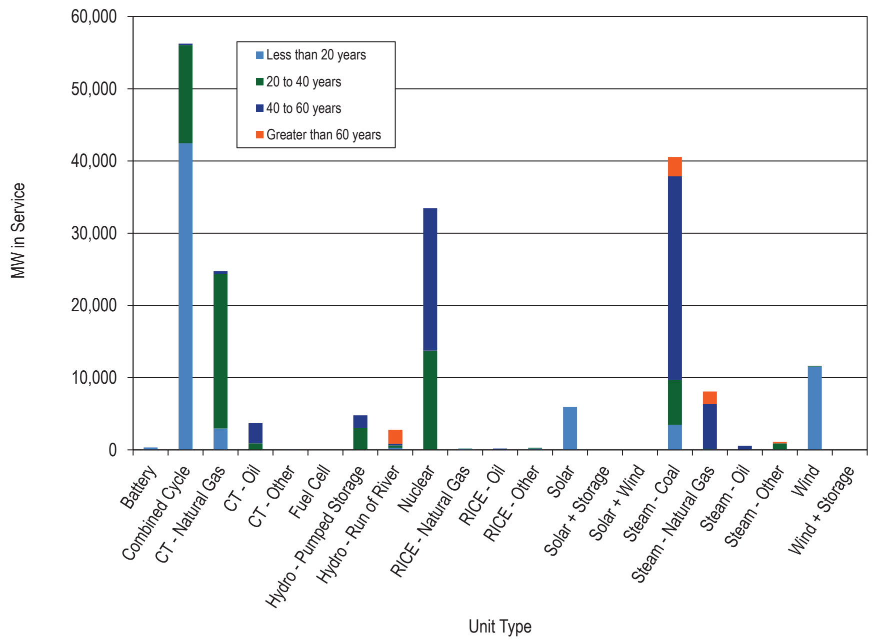


Figure 12-2 is a map of units, less than 20 MW in size that came online between January 1, 2011, and June 30, 2023. A mapping to these unit names is in Table 12-4.

Figure 12-2 Map of unit additions (less than 20 MW): January 1, 2011 through June 30, 2023

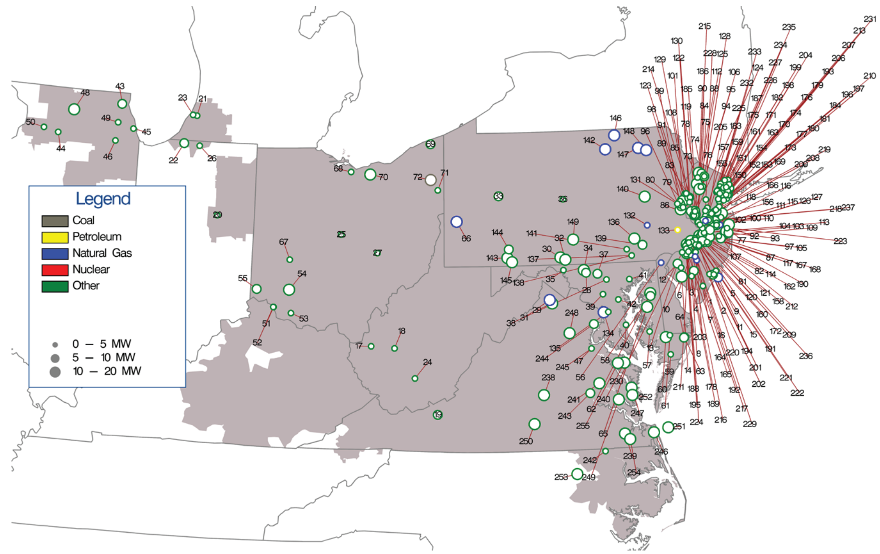


Table 12-4 Unit identification for map of unit additions (less than 20 MW): January 1, 2011 through June 30, 2023

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

Figure 12-3 is a map of units, 20 MW or greater in size, that came online between January 1, 2011 and June 30, 2023. 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 June 30, 2023

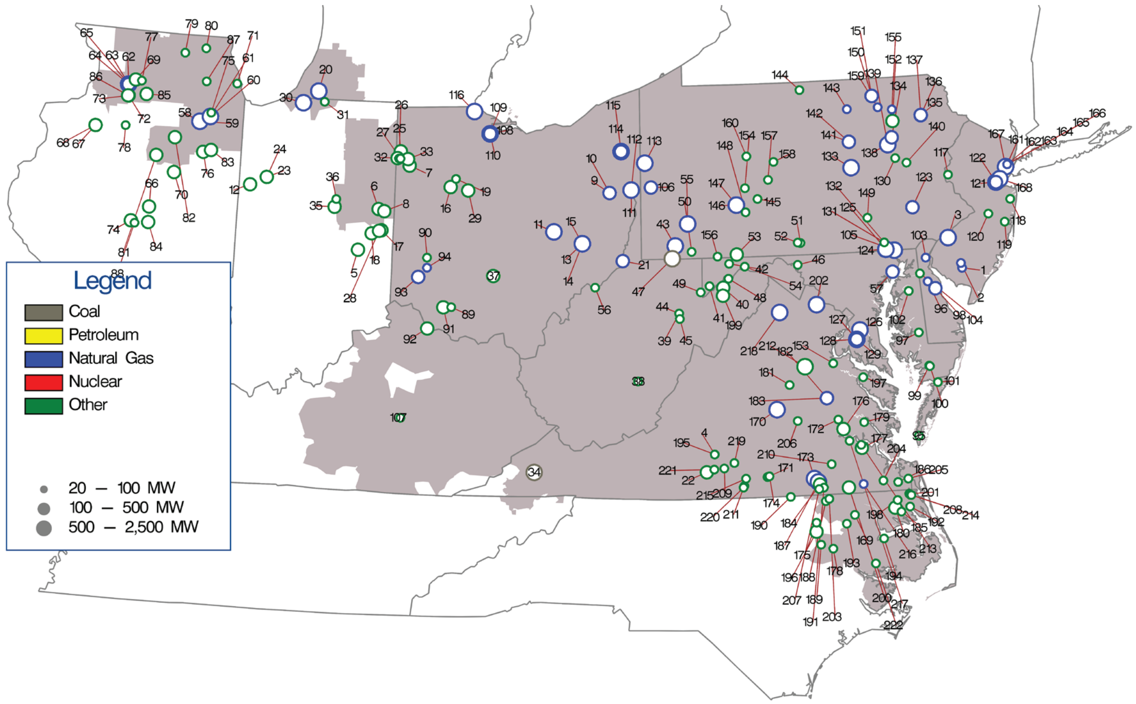


Table 12-5 Unit identification for map of unit additions (20 MW or greater): January 1, 2011 through June 30, 2023

ID	Unit	ID	Unit	ID	Unit	ID	Unit	ID	Unit
1	ACE CLAYVILLE 1 CT	56	AP WILLOW ISLAND 1 H	111	FE HIBBETS MILL SOUTHFIELD 1 CC	166	PS KEARNY 142 CT	221	VP WHITEHORN 1 SP
2	ACE VINELAND 11 CT	57	BC PERRYMAN 6 CT	112	FE HIBBETS MILL SOUTHFIELD 2 CC	167	PS NEWARK ENERGY CENTER 10 CC	222	VP WILKINSON ENERGY CENTER 1 SP
3	ACE WEST DEPTFORD CROWN POINT 1 CC	58	COM 924 THREE RIVERS EC 1 CC	113	FE HICKORY RUN 1 CC	168	PS SEWAREN 7 CC		
4	AEP ALTAVISTA 1 SP	59	COM 924 THREE RIVERS EC 2 CC	114	FE LORDSTOWN ENERGY CENTER 1 CC	169	VP AULANDER HOLLOMAN 1 SP		
5	AEP BELLFLOWER 1 SP	60	COM 929 JACKSON 1 CC	115	FE LORDSTOWN ENERGY CENTER 2 CC	170	VP BEAR GARDEN		
6	AEP BITTER RIDGE 1 WF	61	COM 929 JACKSON 2 CC	116	FE OREGON ENERGY CENTER 1 CC	171	VP BLUESTONE FARM 1 SP		
7	AEP BLUE CREEK 3 WF	62	COM 942 NELSON 1 CC	117	JC EDGE ROAD 5 BT	172	VP BRIEL FARM 1 SP		
8	AEP BLUFF POINT 2 WF	63	COM 942 NELSON 2 CC	118	JC HAMILTON ROAD 5 SP	173	VP BRUNSWICK 1CC		
9	AEP CARROLL COUNTY 1 CC	64	COM 942 NELSON 3 CT	119	JC OAK RIDGE 3 SP	174	VP BUTCHER CREEK 1 SP		
10	AEP CARROLL COUNTY 2 CC	65	COM 942 NELSON 4 CT	120	JC PLUMSTED ENERGY 6 BT	175	VP CHESTNUT 1 SP		
11	AEP DRESDEN 1 CC	66	COM ALTA FARMS II 1 WF	121	JC WOODBRIDGE 1 CC	176	VP CHICKAHOMINY 1 SP		
12	AEP FOWLER RIDGE 4 WF	67	COM BISHOP HILL 1 WF	122	JC WOODBRIDGE 2 CC	177	VP COLONIAL TRAIL WEST 1 SP		
13	AEP GUERNSEY 11 CC	68	COM BISHOP HILL 2 WF	123	ME BIRDSBORO 1 CC	178	VP CONETOE 2 SP		
14	AEP GUERNSEY 21 CC	69	COM BLOOMING GROVE 1 WF1	124	PE DELTA 1-4 CC	179	VP CORRECTIONAL 1 SP		
15	AEP GUERNSEY 31 CC	70	COM BRIGHT STALK 1 WF	125	PE DELTA 5-7 CC	180	VP DESERT 1 WF		
16	AEP HARDIN 2 SP	71	COM GRAND RIDGE 7 BT	126	PEP KEYS ENERGY CENTER 1 CC	181	VP DESPER 1 SP		
17	AEP HEADWATERS 1 WF	72	COM GREEN RIVER 1 WF	127	PEP ST CHARLES - KELSON RIDGE 1 CC	182	VP DOSWELL 2 CT		
18	AEP HEADWATERS 2 WF	73	COM GREEN RIVER 2 WF	128	PEP ST CHARLES-KELSON RIDGE 1 CC	183	VP DOSWELL 3 CT		
19	AEP HOG CREEK 1 WF	74	COM HILLTOPPER 1 WF	129	PEP ST CHARLES-KELSON RIDGE 2 CC	184	VP DRY BREAD 1 SP		
20	AEP INDECK NILES ENERGY CENTER 1 CC	75	COM JOLIET 1 BT	130	PL HAZEL 1 FW	185	VP ELIZABETH CITY 1 SP		
21	AEP LONG RIDGE ENERGY 1 CC	76	COM KELLY CREEK 1 WF	131	PL HOLTWOOD 18	186	VP GRASSFIELD 1 SP		
22	AEP MAPLEWOOD 1 SP	77	COM LEE DEKALB 3 BT	132	PL HOLTWOOD 19	187	VP GREENSVILLE 1 CC		
23	AEP MEADOW LAKE 5 WF	78	COM LONE TREE 3 WF	133	PL HUMMEL STATION 1 CC	188	VP GUTENBERG - OCONECHE 1 SP		
24	AEP MEADOW LAKE 6 WF	79	COM MARENGO 1 BT	134	PL HUNLOCK CC	189	VP HARTS MILL 1 SP		
25	AEP PAULDING 3 WF	80	COM MCHENRY 1 BT	135	PL LACKAWANNA COUNTY 1 CC	190	VP HAWTREE CREEK 1 SP		
26	AEP PAULDING 41 WF	81	COM MINONK 1 WF	136	PL LACKAWANNA COUNTY 2 CC	191	VP IVORY LANE 1 SP		
27	AEP PAULDING 42 WF	82	COM OTTER CREEK 1 WF	137	PL LACKAWANNA COUNTY 3 CC	192	VP IVY NECK 2 SP		
28	AEP RIVERSTART 1 SP	83	COM PILOT HILL 1 WF	138	PL MOXIE FREEDOM 11 CC	193	VP KELFORD 1 SP		
29	AEP SCIOTO RIDGE 1 WF	84	COM RADFORDS RUN 1 WF	139	PL MOXIE FREEDOM 21 CC	194	VP MACKEYS ALBERMAE 1 SP		
30	AEP ST JOSEPH ENERGY CENTER 1 CC	85	COM SHADY OAKS 1 WF	140	PL PA SOLAR 2 SP	195	VP MECHANICSVILLE 2 SP		
31	AEP ST JOSEPH SOLAR PARK 1 SP	86	COM WALNUT RIDGE 1 WF	141	PL PATRIOT 1 F	196	VP MOCCASIN CREEK - FERN 1 SP		
32	AEP TIMBER2 1 WF	87	COM WEST CHICAGO 3 BT	142	PL PATRIOT 2 F	197	VP MONTROSS 1 SP		
33	AEP TRISHE 1 WF	88	COM WHITNEY HILL 2 WF	143	PN BEAVER DAM 1 D	198	VP MORGAN CORNER 1 SP		
34	AEP VIRGINIA CITY 1 F	89	DAY HIGHLAND COUNTY 1 SP	144	PN BIG LEVEL 1 WF	199	VP NEW CREEK 1 WF		
35	AEP WILDCAT 1A WF	90	DAY TAIT 8 BT	145	PN CHESTNUT FLATS 1 WF	200	VP NEWSOMS 1 SP		
36	AEP WILDCAT 1B WF	91	DEOK HILLCREST 1 SP	146	PN FAIRVIEW 1 CC	201	VP OAK TRAIL 1 SP		
37	AEP YELLOWBUD 1 SP	92	DEOK MELDAHL DAM 1 H	147	PN FAIRVIEW 2 CC	202	VP PANDA STONEWALL 1 CC		
38	AP BEECH RIDGE 2 WF	93	DEOK MIDDLETOWN ENERGY 1 CC	148	PN HIGHLAND NORTH 2 WF	203	VP PECAN 1 SP		
39	AP BEECH RIDGE 3 BT	94	DEOK YANKEE 1 F	149	PN LAUREL HILLS 1 WF	204	VP PLEASANT HILL - SUFFOLK 2 SP		
40	AP BLACK ROCK 1 WF	95	DPL CHERRYDALE 1 SP	150	PN LIBERTY ASYLUM 10 F	205	VP POCATY 1 SP		
41	AP FAIR WIND 2 WF	96	DPL DEMEC - CLAYTON 2 CT	151	PN LIBERTY ASYLUM 20 F	206	VP POWHATAN 2 SP		
42	AP FOURMILE RIDGE 1 WF	97	DPL DORCHESTER COUNTY 1 SP	152	PN MEHOOPANY 1 WF	207	VP PUMPKINSEED 1 SP		
43	AP GREENE COUNTY 1 CC	98	DPL GARRISON EC 1 CC	153	PN MEHOOPANY 2 WF	208	VP RANCHLAND 2 SP		
44	AP LAUREL MOUNTAIN 1 BT	99	DPL GREAT BAY KINGS CREEK 1 SP	154	PN PATTON 1 WF	209	VP RENAN 1 SP		
45	AP LAUREL MOUNTAIN 1 WF	100	DPL GREAT BAY KINGS CREEK 2 SP	155	PN PGCOGEN 2 CT	210	VP SAPONY 1 SP		
46	AP MARLOWE 1 SP	101	DPL OAK HALL 1 SP	156	PN RINGER HILL 1 WF	211	VP SOUTH BOSTON 1 F		
47	AP NORTH LONGVIEW 1 F	102	DPL PONDTOWN 2 SP	157	PN SANDY RIDGE 1 WF	212	VP SPOTSYLVANIA 1 SP		
48	AP PINNACLE 1 WF	103	DPL RED LION 1 FC	158	PN SCHOOL HOUSE 1 SP	213	VP SPRING GROVE 1 SP		
49	AP ROTH ROCK 1 WF	104	DPL TOWNSEND 1 SP	159	PN SUGAR RUN 2 CT	214	VP SUMMIT FARMS 1 SP		
50	AP SOUTH CHESTNUT 1 WF	105	DPL WILDCAT POINT 1 CC	160	PN VIADUCT 1 SP	215	VP SUNNYBROOK FARM 1 SP		
51	AP ST THOMAS 1 SP	106	DUQ MONACA-PENNCHEM 1 CC	161	PS KEARNY 131 CT	216	VP UNION CAMP 9-10 F		
52	AP ST THOMAS 2 SP	107	EKPC TURKEY CREEK 1 SP	162	PS KEARNY 132 CT	217	VP WARDS CREEK 1 SP		
53	AP TWIN RIDGES 1 WF	108	FE FREMONT 1 SCCT	163	PS KEARNY 133 CT	218	VP WARREN COUNTY FRONT ROYAL CC		
54	AP WARRIOR RUN 2 BT	109	FE FREMONT 2 SCCT	164	PS KEARNY 134 CT	219	VP WATER STRIDER 1 SP		
55	AP WESTMORELAND 1 CC	110	FE FREMONT ENERGY CENTER 3 CC	165	PS KEARNY 141 CT	220	VP WATLINGTON 1 SP		

Generation Retirements[24] [25]

Generating units generally plan to retire when they are not economic and do not expect to be economic. The MMU performs an analysis of the economics of all units that plan to retire in order to verify that the units are not economic and there is no potential exercise of market power through physical withholding that could advantage the owner's portfolio.[26] 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.[27]

Rules that preserve the Capacity Interconnection Rights (CIRs) associated with retired units, and with the conversion from Capacity Performance (CP) to energy only status, impose significant costs on new entrants. Currently, CIRs persist for one year if unused, and they can be further extended, at no cost, if assigned to a new project in the interconnection queue at the same point of interconnection.[28] There are currently no rules governing the retention of CIRs when units want to convert to energy only status or require time to upgrade to retain CP status. The rules governing conversion or upgrades should be the same as the rules governing retired units. Reforms that require the holders of CIRs to use or lose them, and/or impose costs to holding or transferring them, could make new entry appropriately more attractive. The economic and policy rationale for extending CIRs for inactive units is not clear. Incumbent providers receive a significant advantage simply by imposing on new entrants the entire cost of system upgrades needed to accommodate new entrants. The policy question of whether CIRs should persist after the retirement of a unit should be addressed. Even if the policy treatment of such CIRs remains unchanged, the rules need to ensure that incumbents cannot exploit control of CIRs to block or postpone entry of competitors.

In May 2012, PJM stakeholders (through the Interconnection Process Senior Task Force (IPSTF)) modified the rules to reduce the length of time for which CIRs are retained by the current owner after unit retirements from three years to one.[29] The MMU recognized the progress made in this rule change, but it did not fully address the issues. The MMU recommends that the question of whether CIRs should persist after the retirement of a unit, or conversion from CP to energy only status, be addressed. The rules need to ensure that incumbents cannot exploit control of CIRs to block or postpone entry of competitors.[30]

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 Market Monitor recommends that all capacity resources have a must offer requirement.

24 See PJM. Planning. "Generator Deactivations," (Accessed on June 30, 2023) <https://www.pjm.com/planning/service-requests/gen-deactivations>.
25 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.
26 See OATT Part V and Attachment M–Appendix § IV.
27 See PJM. "*Explaining Power Plant Retirements in PJM*," at <http://learn.pjm.com/three-priorities/planning-for-the-future/explaining-power-plant-retirements.aspx>.
28 See OATT § 230.3.3.
29 See PJM Interconnection, L.L.C., Docket No. ER12-1177 (Feb. 29, 2012).
30 See Comments of the Independent Market Monitor for PJM, Docket No. ER12-1177-000 (March 12, 2012) <http://www.monitoringanalytics.com/Filings/2012/IMM_Comments_ER12-1177-000_20120312.PDF>.

Generation Retirements 2011 through 2026

Table 12-6 shows that as of June 30, 2023, there are 56,155.6 MW of generation that have been, or are planned to be, retired between 2011 and 2026, of which 42,502.8 MW (75.7 percent) are coal fired steam units. Retirements are primarily a result of the inability of coal and other units to compete with efficient combined cycle units burning low cost gas.

Table 12-6 Summary of unit retirements by unit type (MW): 2011 through 2026

	Battery	Combined Cycle	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
Retirements 2011	0.0	0.0	0.0	128.3	0.0	0.0	0.0	0.0	0.0	0.0	2.7	0.0	0.0	0.0	0.0	543.0	522.5	0.0	0.0	0.0	0.0	1,196.5
Retirements 2012	0.0	0.0	250.0	240.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5,907.9	0.0	548.0	16.0	0.0	0.0	6,961.9
Retirements 2013	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.9	7.0	0.0	0.0	0.0	2,589.9	82.0	166.0	8.0	0.0	0.0	2,858.8
Retirements 2014	0.0	0.0	136.0	422.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	15.3	0.0	0.0	0.0	2,239.0	158.0	0.0	0.0	0.0	0.0	2,970.3
Retirements 2015	0.0	0.0	1,319.0	856.2	2.0	0.0	0.0	0.0	0.0	0.0	10.3	0.0	0.0	0.0	0.0	7,064.8	0.0	0.0	0.0	10.4	0.0	9,262.7
Retirements 2016	0.0	0.0	0.0	65.0	6.0	0.0	0.5	0.0	0.0	0.0	8.0	3.9	0.0	0.0	0.0	243.0	74.0	0.0	0.0	0.0	0.0	400.4
Retirements 2017	40.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8	0.0	0.0	0.0	2,038.0	34.0	0.0	0.0	0.0	0.0	2,112.8
Retirements 2018	1.0	425.0	0.0	38.0	1.6	0.0	0.0	0.0	614.5	0.0	17.2	6.9	0.0	0.0	0.0	3,166.5	1,016.0	148.0	108.0	0.0	0.0	5,542.7
Retirements 2019	0.0	0.0	346.8	51.4	6.4	0.0	0.0	0.0	805.0	0.0	0.0	15.9	0.0	0.0	0.0	4,110.5	100.3	10.0	10.0	0.0	0.0	5,456.3
Retirements 2020	0.0	0.0	232.5	24.0	6.0	0.0	0.0	0.0	0.0	0.0	0.0	14.7	0.0	0.0	0.0	2,131.8	0.0	786.0	60.0	0.0	0.0	3,255.0
Retirements 2021	4.0	118.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	15.9	0.0	0.0	0.0	1,020.4	102.0	0.0	50.0	0.0	0.0	1,310.3
Retirements 2022	41.0	240.5	99.0	360.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	37.2	0.0	0.0	0.0	5,385.0	0.0	0.0	0.0	0.0	0.0	6,163.0
Retirements 2023	0.0	0.0	52.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	34.0	19.2	0.0	0.0	0.0	2,496.0	290.0	800.0	0.0	0.0	0.0	3,691.8
Planned Retirements (July 1, 2023 and later)	0.0	0.0	149.2	15.9	0.0	0.0	0.0	0.0	0.0	0.0	2.0	0.0	0.0	0.0	0.0	3,567.0	1,036.0	153.0	50.0	0.0	0.0	4,973.1
Total	86.0	783.5	2,585.1	2,201.1	22.0	0.0	0.5	0.0	1,419.5	0.0	80.1	136.8	0.0	0.0	0.0	42,502.8	3,414.8	2,611.0	302.0	10.4	0.0	56,155.6

Table 12-7 shows the capacity, average size, and average age of units retiring in PJM, from 2011 through 2026, while Table 12-8 shows these retirements by state. Of the 56,155.8 MW of units that has been, or are planned to be, retired between 2011 and 2026, 42,502.8 MW (75.7 percent) are coal fired steam units. These coal fired steam units have an average age of 52.2 years and an average size of 224.9 MW. Over half of the retiring coal fired steam units, 56.0 percent, are located in Ohio or Pennsylvania.

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

Unit Type	Number of Units	Avg. Size (MW)	Avg. Age at Retirement (Years)	Total MW	Percent
Battery	7	12.3	5.9	86.0	0.2%
Combined Cycle	6	130.6	29.1	783.5	1.4%
Combustion Turbine	139	25.2	36.0	4,808.2	8.6%
Natural Gas	67	38.6	42.1	2,585.1	4.6%
Oil	66	33.4	46.6	2,201.1	3.9%
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	2.5%
RICE	42	5.2	26.4	216.9	0.4%
Natural Gas	0	0.0	0.0	0.0	0.0%
Oil	16	5.0	41.0	80.1	0.1%
Other	26	5.3	11.8	136.8	0.2%
Solar	0	0	0	0	0.0%
Solar + Storage	0	0	0	0	0.0%
Solar + Wind	0	0	0	0	0.0%
Steam	229	183.4	45.6	48,830.6	87.0%
Coal	189	224.9	52.2	42,502.8	75.7%
Natural Gas	23	148.5	58.0	3,414.8	6.1%
Oil	8	326.4	47.0	2,611.0	4.6%
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	427	131.5	45.0	56,155.6	100.0%

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

State	Battery	Combined Cycle	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
DC	0.0	0.0	0.0	240.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	548.0	0.0	0.0	0.0	788.0
DE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	664.0	136.0	0.0	0.0	0.0	0.0	800.0
IL	41.0	0.0	296.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	35.7	0.0	0.0	0.0	2,818.1	1,326.0	0.0	0.0	0.0	0.0	4,516.8
IN	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	982.0	0.0	0.0	0.0	0.0	0.0	982.0
KY	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	995.0	0.0	0.0	0.0	0.0	0.0	995.0
MD	0.0	0.0	347.5	169.9	1.6	0.0	0.0	0.0	0.0	0.0	2.0	3.2	0.0	0.0	0.0	4,341.0	171.0	153.0	0.0	0.0	0.0	5,189.2
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	465.5	1,820.2	1,066.2	6.4	0.0	0.5	0.0	614.5	0.0	8.0	23.1	0.0	0.0	0.0	2,001.9	932.5	148.0	10.0	0.0	0.0	7,096.8
OH	42.0	0.0	0.0	307.0	0.0	0.0	0.0	0.0	0.0	0.0	32.3	45.9	0.0	0.0	0.0	16,607.4	0.0	0.0	0.0	0.0	0.0	17,034.6
PA	1.0	51.0	121.4	307.3	14.0	0.0	0.0	0.0	805.0	0.0	13.9	20.5	0.0	0.0	0.0	7,180.0	286.3	176.0	109.0	10.4	0.0	9,095.8
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	0.0	79.7	0.0	0.0	0.0	0.0	0.0	0.0	23.9	8.4	0.0	0.0	0.0	3,897.9	563.0	1,586.0	133.0	0.0	0.0	6,558.9
WV	2.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,691.0	0.0	0.0	0.0	0.0	0.0	2,693.0
Total	86.0	783.5	2,585.1	2,201.1	22.0	0.0	0.5	0.0	1,419.5	0.0	80.1	136.8	0.0	0.0	0.0	42,502.8	3,414.8	2,611.0	302.0	10.4	0.0	56,155.6

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

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

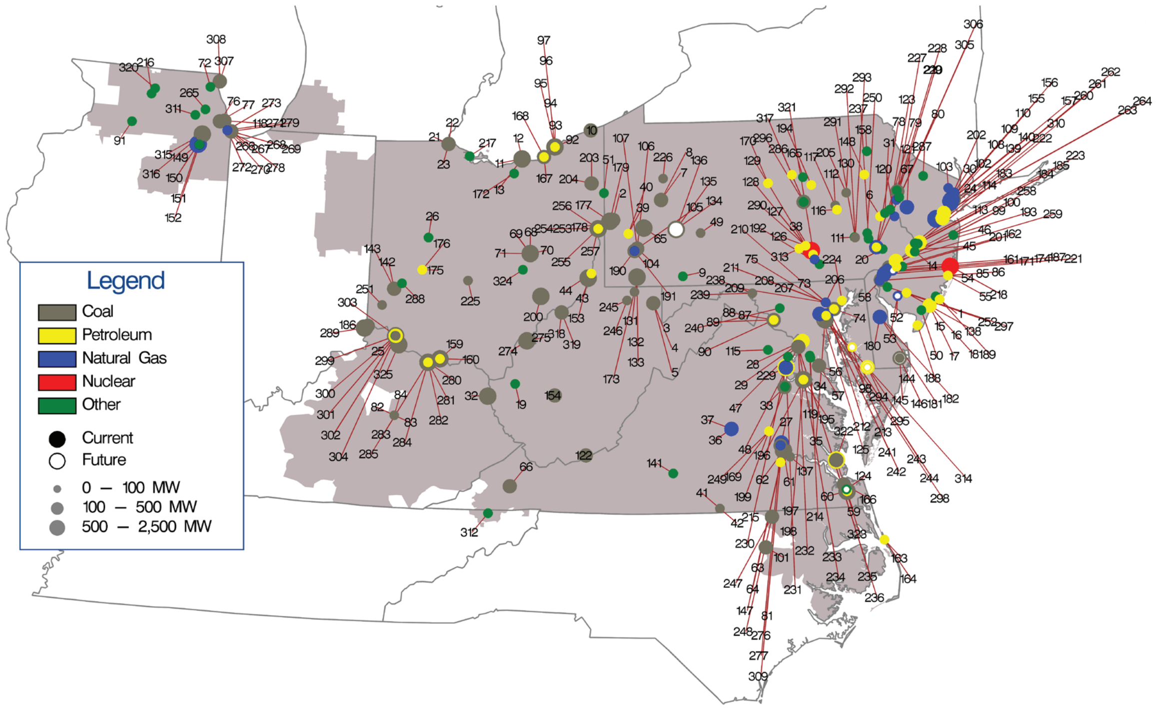


Table 12-9 Unit identification for map of unit retirements: 2011 through 2026

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

Current Year Generation Retirements

Table 12-10 shows that in the first six months of 2023, 3,691.8 MW of generation retired. The largest generator that retired in the first six months of 2023 was the 800.0 MW Yorktown 3 oil fired steam unit located in the DOM Zone. Of the 3,691.8 MW of generation that retired, 1,827.0 MW (49.5 percent) were located in the DOM Zone.

Table 12-10 Unit deactivations: January through June, 2023

Company	Unit Name	ICAP (MW)	Unit Type	Zone Name	Age (Years)	Retirement Date
American Municipal Power, Inc.	Lorain 1 LF	19.2	RICE-Other	ATSI	11	01-Apr-23
Avenue Capital Group LLC	Sammis Diesel Units	13.0	RICE-Oil	ATSI	51	03-May-23
Avenue Capital Group LLC	Sammis Unit 5	290.0	Steam-Coal	ATSI	56	03-May-23
Avenue Capital Group LLC	Sammis Unit 6	600.0	Steam-Coal	ATSI	54	03-May-23
Avenue Capital Group LLC	Sammis Unit 7	600.0	Steam-Coal	ATSI	52	03-May-23
Dominion Energy, Inc.	Yorktown 3	800.0	Steam-Oil	DOM	49	31-May-23
BP P.L.C.	DINWIDDIE 1 CT	3.0	RICE-Oil	DOM	31	01-Jun-23
BP P.L.C.	Lanier 1 CT	7.0	RICE-Oil	DOM	19	01-Jun-23
BP P.L.C.	Rockville CT	4.0	RICE-Oil	DOM	28	01-Jun-23
BP P.L.C.	Weakley CT	7.0	RICE-Oil	DOM	19	01-Jun-23
Dominion Energy, Inc.	Chesterfield 5	336.0	Steam-Coal	DOM	59	01-Jun-23
Dominion Energy, Inc.	Chesterfield 6	670.0	Steam-Coal	DOM	54	01-Jun-23
NRG Energy Inc	Joliet 6	290.0	Steam-Natural Gas	COMED	64	01-Jun-23
Riverstone Holdings LLC	Martins Creek CT 1	18.0	CT-Natural_Gas	PPL	52	01-Jun-23
Riverstone Holdings LLC	Martins Creek CT 2	17.3	CT-Natural_Gas	PPL	52	01-Jun-23
Riverstone Holdings LLC	Martins Creek CT 4	17.3	CT-Natural_Gas	PPL	52	01-Jun-23
Total		3,691.8				

Planned Generation Retirements

Table 12-11 shows that, as of June 30, 2023, there are 4,973.1 MW of generation that have requested retirement after June 30, 2023. Of the 4,973.1 MW requesting retirement, 3,567.0 MW (71.7 percent) are coal fired steam units. As of June 30, 2023, there are planned coal fired unit retirements in three different PJM zones. Of the 4,973.1 MW of planned retirements, 1,884.0 MW (37.9 percent) are located in the PE Zone. Of the generation requesting retirement in the PE Zone, 1,884.0 MW (100.0 percent) are coal fired steam units.

Table 12-11 Planned retirement of units: June 30, 2023

Company	Unit Name	ICAP (MW)	Unit Type	Zone Name	Projected Deactivation Date
The Carlyle Group LP	Homer City 1	620.0	Steam-Coal	PE	01-Jul-23
The Carlyle Group LP	Homer City 2	614.0	Steam-Coal	PE	01-Jul-23
The Carlyle Group LP	Homer City 3	650.0	Steam-Coal	PE	01-Jul-23
NRG Energy Inc	Joliet 7	518.0	Steam-Natural Gas	COMED	01-Sep-23
NRG Energy Inc	Joliet 8	518.0	Steam-Natural Gas	COMED	01-Sep-23
Town of Easton	Easton Diesel Unit 8	2.0	RICE-Oil	DPL	01-Oct-23
Energy Capital Partners LLC	Carlls Corner CT1	37.4	CT-Natural Gas	ACEC	01-Jun-24
Energy Capital Partners LLC	Carlls Corner CT2	41.2	CT-Natural Gas	ACEC	01-Jun-24
Energy Capital Partners LLC	Mickleton CT1	70.6	CT-Natural Gas	ACEC	01-Jun-24
Macquarie Group Limited	Gosport 1 F	50.0	Steam-Other	DOM	01-Jul-24
Riverstone Holdings LLC	Brandon Shores 1	635.0	Steam-Coal	BGE	01-Jun-25
Riverstone Holdings LLC	Brandon Shores 2	638.0	Steam-Coal	BGE	01-Jun-25
NRG Energy Inc	Vienna 8	153.0	Steam-Oil	DPL	01-Jun-25
NRG Energy Inc	Vienna CT 10	15.9	CT-Oil	DPL	01-Jun-25
NRG Energy Inc	Indian River 4	410.0	Steam-Coal	DPL	31-Dec-26
Total		4,973.1			

In addition to the 4,973.1 MW of announced unit retirements as of June 30, 2023, there are significantly more unit retirements expected as a result of state environmental actions. PJM anticipates an additional 20,000 MW of unit retirements between 2024 and 2030, and an additional 10,000 MW of unit retirements between 2031 and 2045.[31]

31 See "Illinois Generation Retirement Study," (August 3, 2022). <http://www.pjm.com/-/media/library/reports-notices/special-reports/2022/2022-pjm-illinois-generation-retirement-study.ashx>.

Generation Queue[32]

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.[33] 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 AI2 opened on October 1, 2022 and closed on March 10, 2023. 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.[34] This change allows more time to review the new requests to the queue without shortening the amount of time available for the resulting model builds and analyses. On August 23, 2021, the Commission approved the tariff modifications.[35]

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

32 The queue totals in this report are the winter net MW energy for the interconnection requests ("MW Energy") as shown in the queue.
33 See OATT Parts IV & VI.
34 See PJM Filing, Docket ER21-2203 (June 24, 2021).
35 176 FERC ¶ 61,117 (2021).

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.[36] 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.[37] 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.[38] 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.[39]

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.[40] The new queue process includes modifications to implement a cluster/cycle based processing method to replace the first in/first out processing method.[41] 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 includes a transition process which treats projects based on their current queue status. All projects through queue window AD2 will continue as part of the previous queue process. The transition process assigns existing queue projects in queue windows AE1 through AH1 to transition cycle 1 and transition cycle 2 and also provides for the expedited treatment (fast track) of projects submitted in the AE1 through AG1 queue windows with upgrade costs less than $5 million. Transition cycle 1 is expected to begin in late 2023. Transition cycle 2 is expected to begin in late 2024. Projects submitted in queue window AH2 and beyond will be evaluated starting in early 2026. While new applications will continue to be accepted, the transition process will delay their consideration for an unknown period.

36 See PJM Filing, Docket ER21-2203 (June 24, 2021).
37 176 FERC ¶ 61,117 (2021).
38 See "PJM Manual 14C: Generation and Transmission Interconnection Process," Rev. 15 (March 22, 2023).
39 PJM does not track the duration of suspensions or PJM termination of projects.
40 181 FERC ¶ 61,162 (2022).
41 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>.

The new process includes modifications to implement a cluster/cycle based processing method to replace the first in/first out processing method.[42] 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 new process includes a transition process which treats projects based on their current queue status. All projects through queue window AD2 will continue as part of the existing queue process. The transition process assigns existing queue projects in queue windows AE1 through AH1 to transition cycle 1 and transition cycle 2 and also provides for the expedited treatment (fast track) of projects submitted in the AE1 through AG1 queue windows with upgrade costs less than $5 million. Transition cycle 1 is expected to begin in late 2023. Transition cycle 2 is expected to begin in late 2024. Projects submitted in queue window AH2 and beyond will be evaluated starting in early 2026. While new applications will continue to be accepted, the transition process will delay their consideration for an unknown period. The transition process itself will not begin until projects eligible for the existing queue process have an executed ISA or the equivalent. After the process for projects in transition cycles 1 and 2 has been completed, projects in queue AH2 and possible subsequent queues will be studied. The new process will not be fully implemented until PJM provides notice that it is accepting applications for the first cycle entirely under the new process. That notice will be provided only after PJM has complete all the prior required transition steps.

On July 15, 2021, the Commission issued an Advance Notice of Proposed Rulemaking (ANOPR).[43] The purpose of the ANOPR is to review transmission related regulations and determine whether additional reforms to the regional transmission planning, cost allocation and generator interconnection processes are needed. The ANOPR discusses the impacts of transmission rules on the competitiveness of the energy markets but does not focus on the competitiveness of transmission itself. Given that the cost of transmission is increasing as a share of total wholesale power costs and now exceeds the cost of capacity in PJM, the cost effectiveness and competitiveness of the transmission planning and procurement process should be addressed when considering reforms.

On June 16, 2022, the Commission issued a Notice of Proposed Rulemaking (NOPR).[44] The NOPR largely aligned with the PJM proposal that has been accepted by FERC.[45] The NOPR addresses reforms to implement a first ready/first served cluster study process, including cluster study costs and an allocation of network upgrade costs to the cluster, increased financial commitments and readiness requirements and improvements to the speed of the queue processing.

The MMU recommends improvements in queue management including that PJM establish a review process to ensure that projects are removed from the queue if they are not viable, as well as a process to allow commercially viable projects to advance in the queue ahead of projects which have failed to make progress, subject to rules to prevent gaming.[46]

42 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>.

43 See *Building for the Future through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, Advanced Notice of Proposed Rulemaking, 176 FERC ¶ 61,024 (July 15, 2021).

44 See *Improvements to Generator Interconnection Procedures and Agreements*, Notice of Proposed Rulemaking, 179 FERC ¶ 61,194 (June 16, 2022).

45 181 FERC ¶ 61,162 (2022).

46 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[47]

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

Table 12-12 Interconnection planning process: study stage

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

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

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

Table 12-13 Interconnection planning process: study stage – additional studies

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

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

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

Table 12-14 Interconnection planning process: construction stage agreements

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

Planned Generation Additions

Expected net revenues provide incentives to build new generation to serve PJM markets. The amount of planned new generation in PJM reflects investors' perception of the incentives provided by the combination of revenues from the PJM energy, capacity and ancillary service markets and from federal and state subsidies and incentives. On June 30, 2023, 287,084.8 MW 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.[48]

There were 287,492.7 MW in generation queues, in the status of active, under construction or suspended, at the end of 2022. In the first six months of 2023, the AI2 closed (on March 10, 2023[49]) and the AJ1 window opened (on April 1, 2023). 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 June 30, 2023, there were 287,084.8 MW in generation queues, in the status of active, under construction or suspended, a decrease of 407.9 MW (0.1 percent) from December 31, 2022. Table 12-15 shows MW in queues by expected completion year and MW changes in the queue between December 31, 2022, and June 30, 2023, for ongoing projects, i.e. projects with the status active, under construction or suspended.[50]

48 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>.
49 The AI2 queue window opened on October 1, 2022.
50 Expected completion dates are entered when the project enters the queue. Actual completion dates are generally different than expected completion dates.

Table 12-15 Queue comparison by expected completion year (MW): December 31, 2022 and June 30, 2023[51]

			Year Change	
Year	As of 12/31/2022	As of 6/30/2023	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	3.4	3.4	0.0	0.0%
2017	0.0	0.0	0.0	0.0%
2018	84.6	44.6	(40.0)	(47.3%)
2019	627.9	387.9	(240.0)	(38.2%)
2020	3,911.4	2,239.4	(1,672.0)	(42.7%)
2021	17,268.8	14,654.6	(2,614.2)	(15.1%)
2022	32,264.7	28,704.4	(3,560.3)	(11.0%)
2023	52,579.2	51,313.7	(1,265.5)	(2.4%)
2024	64,390.8	66,243.4	1,852.7	2.9%
2025	47,670.9	50,707.4	3,036.5	6.4%
2026	25,603.5	29,637.5	4,034.0	15.8%
2027	14,972.0	19,304.0	4,332.0	28.9%
2028	6,103.8	7,405.8	1,302.0	21.3%
2029	9,358.1	11,067.7	1,709.6	18.3%
2030	290.0	3,770.9	3,480.9	1200.3%
2031	1,600.0	1,600.0	0.0	0.0%
Total	276,729.1	287,084.8	10,355.7	3.7%

Table 12-16 shows the project status changes in more detail and how scheduled queue MW have changed between December 31, 2022, and June 30, 2023. For example, 10,355.7 MW entered the queue in the first six months of 2023. Of the total 272,832.5 MW marked as active on December 31, 2022, 5,235.0 MW were withdrawn, 3,190.4 MW were suspended, 1,186.6 MW started construction, and 121.3 MW went into service by June 30, 2023. Analysis of projects that were suspended on December 31, 2022 show that 810.1 MW came out of suspension and are now active as of June 30, 2023.

Table 12-16 Change in project status (MW): December 31, 2022 to June 30, 2023

		Status at 6/30/2023				
Status at 12/31/2022	Total at 12/31/2022	Active	In Service	Under Construction	Suspended	Withdrawn
(Entered during 2023)	0.0	10,355.7	0.0	0.0	0.0	0.0
Active	272,832.5	263,097.2	121.3	1,188.6	3,190.4	5,235.0
In Service	81,291.8	0.0	81,290.8	0.0	0.0	1.0
Under Construction	7,443.6	0.0	4,337.9	3,061.8	0.0	43.9
Suspended	6,281.0	810.1	0.0	0.0	5,380.9	90.0
Withdrawn	449,592.9	0.0	0.0	0.0	0.0	449,592.9
Total	817,441.9	274,263.0	85,750.0	4,250.4	8,571.3	454,962.8

On June 30, 2023, 287,084.8 MW were in generation request queues in the status of active, suspended or under construction. Table 12-17 shows each status by unit type. Of the 274,263.0 MW in the status of Active on June 30, 2023, 4,891.0 MW (1.8 percent) were combined cycle projects. Of the 4,250.4 MW in the status of under construction, 350.4 MW (8.2 percent) were combined cycle projects. A significant amount of renewable hybrid projects (defined as solar + storage, solar + wind and wind + storage projects) have entered the queue in recent years. Of the 274,263.0 MW in the status of Active on June 30, 2023, 37,511.1 MW (13.7 percent) were renewable hybrid projects. Of the 4,250.4 MW in the status of under construction, 22.7 MW (0.5 percent) were renewable hybrid projects.

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

Table 12-17 Current project status (MW) by unit type: June 30, 2023

	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	56,645.5	4,891.0	3,122.2	0.0	53.8	5.0	730.0	112.8	0.0	14.4	0.0	0.0	122,477.2	37,152.1	209.0	29.0	0.0	0.0	20.0	48,651.1	150.0	274,263.0
Suspended	27.0	3,950.0	675.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3,425.2	414.1	0.0	0.0	0.0	0.0	0.0	80.0	0.0	8,571.3
Under Construction	35.0	350.4	32.0	8.0	0.0	0.0	0.0	0.0	44.0	0.0	0.0	0.0	3,528.9	22.7	0.0	36.0	5.0	0.0	0.0	188.4	0.0	4,250.4
Total	56,707.5	9,191.4	3,829.2	8.0	53.8	5.0	730.0	112.8	44.0	14.4	0.0	0.0	129,431.3	37,589.0	209.0	65.0	5.0	0.0	20.0	48,919.5	150.0	287,084.8

A significant shift in the distribution of unit types within the PJM footprint continues to develop as natural gas fired units and renewable, hybrid and other intermittent resources enter the queue and coal fired steam units retire. As of June 30, 2023, of the 287,084.8 MW in the generation request queues in the status of active, suspended or under construction, 129,431.3 MW (45.1 percent) were solar projects, 48,919.5 MW (17.0 percent) were wind projects, 13,040.0 MW (4.5 percent) were natural gas fired projects (including combined cycle units, CTs, RICE units, and natural gas fired steam units), 37,948.0 MW (13.2 percent) were renewable hybrid projects (solar + storage, solar + wind and wind + storage units), and 65.0 MW (0.02 percent) were coal fired steam projects.

As of June 30, 2023, there are 3,567.0 MW of coal fired steam units and 1,185.2 MW of natural gas units slated for deactivation between July 1, 2023, and December 31, 2026 (See Table 12-11). The ongoing replacement of coal fired steam units by natural gas units will continue to significantly affect future congestion, the role of firm and interruptible gas supply, and natural gas supply infrastructure. The growing level of renewables, hybrids and other intermittents will also have increasingly significant impacts on the energy and capacity markets.

Table 12-18 shows the total MW in the status of active, in service, under construction, suspended, or withdrawn for each queue since the beginning of the RTEP process and the total MW that had been included in each queue. All items in queues A-R are either in service or have been withdrawn. As of June 30, 2023, there are 287,084.8 MW in queues that are not yet in service or withdrawn, of which 3.0 percent are suspended, 1.5 percent are under construction and 95.5 percent have not begun construction.

Table 12-18 Queue totals by status (MW): June 30, 2023[52]

Queue	Active	In Service	Under Construction	Suspended	Withdrawn	Total
A Expired 31-Jan-98	0.0	9,094.0	0.0	0.0	17,252.0	26,346.0
B Expired 31-Jan-99	0.0	4,292.4	0.0	0.0	14,958.8	19,251.2
C Expired 31-Jul-99	0.0	531.0	0.0	0.0	3,558.3	4,089.3
D Expired 31-Jan-00	0.0	850.6	0.0	0.0	7,358.0	8,208.6
E Expired 31-Jul-00	0.0	795.2	0.0	0.0	8,021.8	8,817.0
F Expired 31-Jan-01	0.0	52.0	0.0	0.0	3,092.5	3,144.5
G Expired 31-Jul-01	0.0	1,171.6	0.0	0.0	17,961.8	19,133.4
H Expired 31-Jan-02	0.0	702.5	0.0	0.0	8,421.9	9,124.4
I Expired 31-Jul-02	0.0	103.0	0.0	0.0	3,728.4	3,831.4
J Expired 31-Jan-03	0.0	42.0	0.0	0.0	846.0	888.0
K Expired 31-Jul-03	0.0	93.1	0.0	0.0	485.3	578.4
L Expired 31-Jan-04	0.0	256.5	0.0	0.0	4,033.7	4,290.2
M Expired 31-Jul-04	0.0	504.8	0.0	0.0	3,705.6	4,210.4
N Expired 31-Jan-05	0.0	2,398.8	0.0	0.0	8,129.3	10,528.0
O Expired 31-Jul-05	0.0	1,890.2	0.0	0.0	5,466.8	7,357.0
P Expired 31-Jan-06	0.0	3,290.3	0.0	0.0	5,320.5	8,610.8
Q Expired 31-Jul-06	0.0	3,147.9	0.0	0.0	11,385.7	14,533.6
R Expired 31-Jan-07	0.0	1,892.5	0.0	0.0	20,708.9	22,601.4
S Expired 31-Jul-07	70.0	3,543.5	0.0	0.0	12,396.5	16,010.0
T Expired 31-Jan-08	0.0	4,196.5	0.0	0.0	23,313.3	27,509.8
U1 Expired 30-Apr-08	0.0	218.9	0.0	0.0	7,937.8	8,156.7
U2 Expired 31-Jul-08	0.0	716.9	0.0	0.0	16,218.6	16,935.5
U3 Expired 31-Oct-08	0.0	333.0	0.0	0.0	2,635.6	2,968.6
U4 Expired 31-Jan-09	0.0	85.2	0.0	0.0	4,945.0	5,030.2
V1 Expired 30-Apr-09	0.0	197.9	0.0	0.0	2,572.8	2,770.7
V2 Expired 31-Jul-09	0.0	989.9	16.1	0.0	3,625.1	4,631.1
V3 Expired 31-Oct-09	0.0	1,132.0	0.0	0.0	3,822.7	4,954.7
V4 Expired 31-Jan-10	0.0	748.8	0.0	0.0	3,708.0	4,456.8
W1 Expired 30-Apr-10	0.0	567.4	0.0	0.0	5,139.5	5,706.9
W2 Expired 31-Jul-10	0.0	351.7	0.0	0.0	3,051.7	3,403.4
W3 Expired 31-Oct-10	0.0	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	1,630.5	0.0	0.0	4,609.2	6,239.6
Z1 Expired 31-Oct-13	189.0	3,094.5	0.0	675.0	4,055.0	8,013.5
Z2 Expired 30-Apr-14	0.0	3,062.0	0.0	0.0	3,037.8	6,099.8
AA1 Expired 31-Oct-14	90.2	4,868.9	150.0	0.0	6,961.4	12,070.5
AA2 Expired 30-Apr-15	1,098.0	3,009.6	15.0	0.0	11,943.7	16,066.3
AB1 Expired 31-Oct-15	1,226.8	2,678.3	158.4	2,700.0	13,690.3	20,453.7
AB2 Expired 31-Mar-16	924.8	3,372.5	170.1	80.0	10,608.4	15,155.8
AC1 Expired 30-Sep-16	1,485.8	4,053.7	1,748.8	400.0	12,347.7	20,035.9
AC2 Expired 30-Apr-17	2,058.3	816.5	250.3	236.7	9,207.8	12,569.6
AD1 Expired 30-Sep-17	3,169.9	432.9	456.6	447.5	6,774.7	11,281.6
AD2 Expired 31-Mar-18	3,228.1	855.7	555.2	435.8	15,226.1	20,300.8
AE1 Expired 30-Sep-18	11,722.2	138.5	271.0	1,882.1	19,693.1	33,706.9
AE2 Expired 31-Mar-19	18,285.1	316.0	350.8	1,093.0	13,782.6	33,827.4
AF1 Expired 30-Sep-19	18,901.4	76.8	22.0	469.6	9,319.0	28,788.8
AF2 Expired 31-Mar-20	20,202.5	92.9	60.2	102.5	7,609.6	28,067.5
AG1 Expired 30-Sep-20	31,752.5	0.5	25.0	46.2	6,157.5	37,981.7
AG2 Expired 31-Mar-21	54,093.9	0.0	1.0	3.0	2,651.4	56,749.3
AH1 Expired 10-Sep-21	45,538.2	0.0	0.0	0.0	4,420.3	49,958.6
AH2 Expired 10-Mar-22	27,432.2	0.0	0.0	0.0	6,896.8	34,329.0
AI1 Expired 10-Sep-22	21,968.2	0.0	0.0	0.0	1,539.8	23,508.0
AI2 Expired 10-Mar-23	8,191.4	0.0	0.0	0.0	0.0	8,191.4
AJ1 Opened 1-Apr-23	2,634.4	0.0	0.0	0.0	0.0	2,634.4
Total	274,263.0	85,750.0	4,250.4	8,571.3	454,962.8	827,797.5

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

Table 12-19 shows the projects with a status of active, suspended or under construction, by unit type, and control zone. As of June 30, 2023, 287,084.8 MW were in generation request queues for construction through 2031. Table 12-19 also shows the planned retirements for each zone.

Table 12-19 Queue totals for projects (active, suspended and under construction) by LDA, control zone and unit type (MW): June 30, 2023[53]

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	1,924.2	0.0	230.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	623.3	266.0	0.0	0.0	0.0	0.0	0.0	3,141.6	0.0	6,185.1	149.2
	DPL	1,064.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,173.8	286.5	0.0	0.0	0.0	0.0	0.0	7,369.5	0.0	10,893.8	580.9
	JCPLC	1,586.8	0.0	0.0	0.0	0.0	0.0	30.0	0.0	0.0	0.0	0.0	0.0	715.6	165.0	0.0	0.0	0.0	0.0	0.0	16,390.1	0.0	18,887.5	0.0
	PECO	0.0	5.0	0.0	0.0	0.0	0.0	0.0	0.0	44.0	0.0	0.0	0.0	129.4	5.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	183.4	0.0
	PSEG	1,582.0	51.1	675.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	59.2	22.6	0.0	0.0	5.0	0.0	0.0	2,610.0	0.0	5,004.9	0.0
	REC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	EMAAC Total	6,157.0	56.1	905.0	0.0	0.0	0.0	30.0	0.0	44.0	0.0	0.0	0.0	3,701.3	745.1	0.0	0.0	5.0	0.0	0.0	29,511.2	0.0	41,154.6	730.1
SWMAAC	BGE	1,458.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	154.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,613.4	1,273.0
	PEPCO	1,918.0	45.0	35.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	210.7	1,452.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3,661.0	0.0
	SWMAAC Total	3,376.5	45.0	35.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	365.6	1,452.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5,274.4	1,273.0
WMAAC	MEC	836.2	75.0	11.5	6.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	823.1	322.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,074.5	0.0
	PE	1,367.8	30.0	20.5	0.0	3.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6,020.0	1,696.6	0.0	0.0	0.0	0.0	0.0	574.3	0.0	9,712.8	1,884.0
	PPL	420.0	51.6	0.0	0.0	0.0	0.0	700.0	0.0	0.0	0.0	0.0	0.0	2,672.7	790.0	0.0	0.0	0.0	0.0	0.0	174.8	0.0	4,809.1	0.0
	WMAAC Total	2,624.0	156.6	32.0	6.5	3.6	0.0	700.0	0.0	0.0	0.0	0.0	0.0	9,515.8	2,808.8	0.0	0.0	0.0	0.0	0.0	749.1	0.0	16,596.4	1,884.0
Non-MAAC	AEP	11,375.9	1,485.0	791.0	0.0	40.1	0.0	0.0	51.0	0.0	0.0	0.0	0.0	45,306.4	13,910.8	0.0	65.0	0.0	0.0	0.0	2,550.9	0.0	75,576.1	0.0
	AMPT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	206.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	206.0	0.0
	APS	3,431.5	4,700.0	30.0	0.0	0.0	0.0	0.0	15.0	0.0	14.4	0.0	0.0	6,601.5	3,525.3	0.0	0.0	0.0	0.0	0.0	1,029.1	0.0	19,346.8	0.0
	ATSI	2,418.0	1,953.0	458.7	1.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6,848.0	721.6	0.0	0.0	0.0	0.0	0.0	297.7	0.0	12,698.4	0.0
	COMED	9,718.2	677.7	419.2	0.0	0.0	5.0	0.0	0.0	0.0	0.0	0.0	0.0	13,467.9	2,973.5	199.0	0.0	0.0	0.0	0.0	9,374.1	0.0	36,834.5	1,036.0
	DAY	290.0	0.0	20.0	0.0	10.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3,608.4	650.8	0.0	0.0	0.0	0.0	0.0	100.0	0.0	4,679.3	0.0
	DUKE	527.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	678.9	40.0	10.0	0.0	0.0	0.0	0.0	0.0	0.0	1,256.1	0.0
	DLCO	505.0	0.0	0.0	0.0	0.0	0.0	0.0	46.8	0.0	0.0	0.0	0.0	88.9	107.5	0.0	0.0	0.0	0.0	20.0	0.0	0.0	768.2	0.0
	DOM	16,108.2	118.0	1,138.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	31,717.6	8,117.1	0.0	0.0	0.0	0.0	0.0	5,307.5	150.0	62,656.4	50.0
	EKPC	176.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6,895.0	2,358.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	9,429.1	0.0
	OVEC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	430.0	178.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	608.5	0.0
	RMU	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Non-MAAC Total	44,550.0	8,933.7	2,856.9	1.5	50.2	5.0	0.0	112.8	0.0	14.4	0.0	0.0	115,848.6	32,583.0	209.0	65.0	0.0	0.0	20.0	18,659.3	150.0	224,059.3	1,086.0
Total		56,707.5	9,191.4	3,829.2	8.0	53.8	5.0	730.0	112.8	44.0	14.4	0.0	0.0	129,431.3	37,589.0	209.0	65.0	5.0	0.0	20.0	48,919.5	150.0	287,084.8	4,973.1

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.[54] PJM derated solar resources to 38 percent of nameplate capacity. Effective June 1, 2017, PJM adjusted the derates of wind and solar resources. The capacity factor derates for wind resources are dependent on the wind farm locations and have an average derate of 16.2 percent. The capacity factor derates for solar resources are dependent on the solar installation type and have an average derate of 46.7 percent.

Beginning with the 2023/2024 Delivery Year, unforced capacity for intermittent resources and limited duration resources will be determined by PJM's effective load carrying capability (ELCC) analysis. The PJM ELCC analysis will determine capacity derates by resource class. The unforced capacity derate for a specific resource will equal the product of the ELCC class rating and a resource specific performance factor. The 2023/2024 ELCC class rating for wind resources is 15.0 percent, for solar resources with tracking panels is 54.0 percent and for solar resources with fixed panels is 38.0 percent.[55] 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

53 This data includes only projects with a status of active, under construction, or suspended.
54 See "PJM Manual 14B: PJM Region Transmission Planning Process," Rev. 52 (April 10, 2023).
55 *ELCC Class Ratings for 2023-2024 BRA*, PJM Interconnection L.L.C. (December 16, 2021) <https://www.pjm.com/planning/resource-adequacy-planning/effective-load-carrying-capability>

defined four different energy storage classes differentiated by duration. The ELCC class rating is 83.0 percent for storage resources that can continuously generate energy at the nameplate capacity for four hours (four hour storage). The ELCC class rating is 98.0 percent for six hour storage and 100 percent for 8 hour storage and 10 hour storage.[56] Using the ELCC derate factors, based on the derating of 48,919.5 MW of wind resources to 7,337.9 MW, 129,431.3 MW of solar resources to 69,892.9 MW, 37,589.0 MW of solar + storage resources to 20,298.0 MW, 209.0 MW of solar + wind resources to 112.9 MW, 150.0 MW of wind + storage resources to 22.5 MW and 56,707.5 MW of battery resources to 47,067.2 MW, the 287,084.8 MW currently under construction, suspended or active in the queue would be reduced to 158,810.0 MW.[57]

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.[58] The impact and facilities studies are performed using the full amount of planned generation in the queues. The actual withdrawal rates are shown in Table 12-20 and Table 12-21.

Table 12-20 shows the milestone status when projects were withdrawn, for all withdrawn projects. Of the 3,543 projects withdrawn as of June 30, 2023, 1,757 (49.6 percent) were withdrawn before the system impact study was completed. Once a Construction Service Agreement (CSA) is executed, the financial obligation for any necessary transmission upgrades cannot be retracted. Of the 3,543 projects withdrawn, 672 (19.0 percent) were withdrawn after the completion of a Construction Service Agreement.

Table 12-20 Last milestone at time of withdrawal: January 1, 1997 through June 30, 2023

Milestone Completed	Projects Withdrawn	Percent	Average Days	Maximum Days
Never Started	715	20.2%	289	1,193
Feasibility Study	1,042	29.4%	273	1,633
System Impact Study	778	22.0%	734	3,248
Facilities Study	336	9.5%	1,180	4,107
Construction Service Agreement (CSA) or beyond	672	19.0%	1,401	7,864
Total	3,543	100.0%		

Average Time in Queue

Table 12-21 shows the time spent at various stages in the queue process and the completion time for the studies performed. For completed projects, there is an average time of 1,142 days, or 3.1 years, between entering a queue and going into service. For withdrawn projects, there is an average time of 655 days, or 1.8 years, between entering a queue and withdrawing.

Table 12-21 Project queue times by status (days): June 30, 2023[59]

Status	Average (Days)	Standard Deviation	Maximum
Active	841	521	5,947
In-Service	1,142	806	5,306
Suspended	1,681	522	3,529
Under Construction	2,039	638	5,145
Withdrawn	655	752	7,864

Table 12-22 presents information on the time in the stages of the queue for those projects not yet in service or already withdrawn. Of the 3,521 projects in the queue as of June 30, 2023, 169 (4.8 percent) had a completed feasibility study and 539 (15.3 percent) had a completed construction service agreement.

56 Additional information available in *PJM Manual 21A: Determination of Accredited UCAP Using Effective Load Carrying Capability Analysis*, PJM Interconnection L.L.C., Rev. 2 (April 10, 2023).
57 The ELCC derate adjusted MW are calculated using the four hour storage ELCC derate of 83.0 percent for battery resources, 15.0 percent ELCC derate for wind resources and 54.0 percent ELCC derate for solar resources.
58 See "PJM Manual 14B: PJM Region Transmission Planning Process," Rev. 52 (April 10, 2023).
59 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 12-22 Project queue times by milestone (days): June 30, 2023

Milestone Reached	Number of Projects	Percent of Total Projects	Average Days	Maximum Days
Under Review	2,168	61.6%	1,393	1,885
Feasibility Study	169	4.8%	1,050	1,395
System Impact Study	579	16.4%	1,245	1,795
Facilities Study	66	1.9%	1,557	2,285
Construction Service Agreement (CSA) or beyond	539	15.3%	1,781	5,947
Total	3,521	100.0%		

Table 12-23 shows the time spent in the queue by fuel type, and year the project entered the queue, for projects that are in service. The time from when a project enters the queue to the time the project goes in service has generally been decreasing compared to the period prior to 2017 although there are significant exceptions. For example, for a battery project entering the queue in 2015, there was an average of 1,082 days from the time it entered the queue until it went in service, compared to only 293 days when entering the queue in 2018, but the time increased to 600 days for battery projects entering the queue in 2019.

Table 12-23 Average time in queue (days) by fuel type and year submitted (In Service Projects): June 30, 2023[60]

Unit Type	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Battery	983	609	417	692	789	1,082	941		293	600	544			
CC	1,310	1,551	1,663	1,419	1,175	1,208	1,191	1,047	883	512				
CT - Natural Gas	1,131	804	953	1,073	1,409	619	1,566	1,038	805	357	805			
CT - Oil	717		259							280				
CT - Other	729	634	954	1,248	718	360								
Fuel Cell						827	643			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						
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	1,701	1,505	1,315	892	802	548			
Solar + Storage									553					
Solar + Wind														
Steam - Coal	745		513	1,010	583	853	684	647	1,122					
Steam - Natural Gas				1,182		421	751							
Steam - Oil														
Steam - Other	256	838	643											
WInd	2,748	2,711	1,750	1,589	1,205	1,463	1,637	1,398	934		997			
Wind + Storage							1,189							

60 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.

Completion Rates

The probability of a project going into service increases as each step of the planning process is completed. Table 12-24 shows the historic completion rates (MW energy) by unit type for projects that have completed the system impact study (SIS), facilities study agreement (FSA) and any milestone completed beyond the FSA including a Construction Service Agreement (CSA), Interconnection Service Agreement (ISA), Upgrade Construction Service Agreement (UCSA) and Wholesale Market Participant Agreement (WMPA) as well as the historic completion rates for all projects including those withdrawn before reaching the SIS milestone.[61] 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, 10.1 percent of the queued MW have gone into service. The completion rate for battery projects increases to 29.2 percent when battery projects complete the facility study agreement and further increases to 36.4 percent when battery projects complete the construction service agreement. Of all battery projects to enter the queue, only 0.4 percent of the queued MW have gone into service.

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

Table 12-24 Historic completion rates (MW energy) by unit type for projects with a completed SIS, FSA and CSA: June 30, 2023

Unit Type	Completion Rate (SIS)	Completion Rate (FSA)	Completion Rate (CSA)	Completion Rate (ALL)
Battery	10.1%	29.2%	36.4%	0.4%
CC	34.3%	50.7%	73.9%	16.4%
CT - Natural Gas	64.5%	77.4%	80.8%	46.1%
CT - Oil	35.4%	59.8%	90.9%	25.4%
CT - Other	12.1%	18.4%	29.5%	8.4%
Fuel Cell	52.8%	54.1%	54.1%	30.2%
Hydro - Pumped Storage	100.0%	100.0%	100.0%	24.1%
Hydro - Run of River	42.5%	60.0%	67.2%	20.9%
Nuclear	34.7%	41.9%	51.3%	28.5%
RICE - Natural Gas	30.7%	42.8%	47.4%	25.9%
RICE - Oil	34.0%	59.7%	59.7%	24.6%
RICE - Other	88.9%	91.3%	92.0%	77.9%
Solar	21.2%	42.6%	57.4%	3.1%
Solar + Storage	0.0%	0.2%	0.4%	0.0%
Solar + Wind	0.0%	0.0%	0.0%	0.0%
Steam - Coal	13.7%	25.5%	37.6%	6.3%
Steam - Natural Gas	90.5%	91.1%	91.1%	90.0%
Steam - Oil	0.0%	0.0%	0.0%	0.0%
Steam - Other	30.4%	39.9%	47.8%	27.1%
Wind	18.5%	35.8%	52.2%	7.1%
Wind + Storage	0.0%	0.0%	0.0%	0.0%

On June 30, 2023, 287,084.8 MW were in generation request queues in the status of active, under construction or suspended. Of the total 287,084.8 MW in the queue, 180,872.5 MW (63.0 percent) have reached at least the SIS milestone and 106,212.3 MW (37.0 percent) have not received a completed SIS. Based on historical completion rates, (applying the unit type specific completion rates for those projects that have reached the SIS, FSA or any milestone beyond the FSA, and using the overall completion rates for those projects that have not yet reached the SIS milestone), 42,040.6 MW (14.6 percent) of new generation in the queue are expected to go into service.

Table 12-25 shows the percent of all project MW, by unit type, to go in service by year submitted to the queue. Of all battery projects that entered the queue in 2010, 65.5 percent reached the status of in service by June 30, 2023. Of all battery projects that entered the queue in 2016, only 1.3 percent have reached the status of in service as of June 30, 2023.

Table 12-25 Percent of all projects (MW energy) to go in service by unit type and year submitted to the queue: June 30, 2023

Unit Type	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Battery	65.5%	8.3%	15.1%	43.9%	21.5%	7.7%	1.3%	0.0%	0.3%	0.0%	0.0%	0.0%	0.0%	0.0%
CC	14.6%	24.5%	30.8%	35.6%	53.6%	13.4%	20.4%	7.1%	3.3%	0.5%	0.0%	0.0%	0.0%	NA
CT - Natural Gas	100.0%	98.3%	71.6%	42.2%	56.8%	0.2%	13.2%	32.3%	7.8%	3.5%	7.2%	0.0%	0.0%	NA
CT - Oil	100.0%	NA	1.2%	0.0%	0.0%	NA	NA	NA	0.0%	38.5%	0.0%	NA	NA	NA
CT - Other	28.8%	26.2%	36.1%	100.0%	0.0%	100.0%	NA	0.0%	NA	NA	NA	0.0%	NA	NA
Fuel Cell	NA	NA	NA	NA	NA	67.4%	12.5%	0.0%	NA	100.0%	NA	0.0%	NA	NA
Hydro - Pumped Storage	NA	NA	NA	NA	NA	100.0%	NA	NA	0.0%	0.0%	NA	0.0%	NA	NA
Hydro - Run of River	0.0%	0.0%	57.6%	49.6%	11.2%	NA	100.0%	26.8%	100.0%	0.0%	0.0%	0.0%	NA	NA
Nuclear	15.5%	1.6%	0.0%	100.0%	NA	NA	25.4%	100.0%	100.0%	NA	0.0%	NA	NA	NA
RICE - Natural Gas	NA	NA	100.0%	66.7%	5.4%	6.2%	0.0%	5.4%	NA	NA	NA	0.0%	NA	NA
RICE - Oil	0.0%	0.0%	NA	NA	NA	30.8%	NA	NA	NA	NA	NA	NA	0.0%	NA
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
Solar	10.7%	8.1%	16.9%	24.4%	30.7%	25.2%	22.7%	4.4%	0.6%	1.0%	0.1%	0.0%	0.0%	0.0%
Solar + Storage	NA	NA	NA	NA	NA	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Solar + Wind	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	0.0%	0.0%	NA	NA
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
Steam - Natural Gas	NA	NA	NA	100.0%	0.0%	100.0%	100.0%	100.0%	NA	NA	0.0%	NA	NA	NA
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%
Steam - Other	0.5%	61.2%	16.6%	0.0%	0.0%	NA	NA	NA	NA	NA	NA	0.0%	NA	NA
WInd	6.1%	3.4%	2.5%	6.3%	20.7%	12.5%	18.1%	2.6%	0.6%	0.0%	0.0%	0.0%	0.0%	0.0%
Wind + Storage	NA	NA	NA	NA	NA	NA	100.0%	0.0%	NA	NA	NA	NA	0.0%	NA
All	11.6%	19.0%	25.9%	34.5%	42.3%	15.3%	20.8%	5.5%	1.5%	0.6%	0.1%	0.0%	0.0%	0.0%

Table 12-26 shows the total MW that went in service each year, by unit type, since 1999. In the first six months of 2023, 2,253.9 MW from the queue went in service. Of the 2,253.9 MW that went in service, 1,449.0 MW (64.3 percent) were combined cycle units, 468.1 MW (20.8 percent) were combustion turbine natural gas units, 200 MW (8.6 percent) were wind units and 136.8 MW (6.1 percent) were solar units.

Table 12-26 Total (MW Energy) by unit type and year project went in service: June 30, 2023

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
Battery	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	27.4	4.5	23.0	24.0	110.4	10.0	2.0	40.0	25.5	0.0	1.5	0.0	0.0
CC	0.0	0.0	100.0	2,608.0	2,785.0	2,845.0	15.1	1,196.0	22.0	177.0	52.0	136.0	1,869.0	162.7	82.2	2,155.7	2,977.7	5,418.0	3,888.1	10,865.0	2,881.4	88.0	3,424.7	2,850.9	1,449.0
CT - Natural Gas	0.0	401.6	432.0	2,442.0	638.7	61.3	993.0	39.3	97.0	821.0	181.7	97.8	850.4	393.0	95.0	125.2	317.9	72.0	212.0	388.0	104.0	142.0	328.4	153.5	468.1
CT - Oil	0.0	0.0	315.0	6.5	0.0	33.0	292.0	7.5	21.0	15.3	85.6	0.0	23.9	2.0	0.5	2.0	0.0	0.0	0.0	0.0	0.0	5.0	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
Fuel Cell	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.9	0.0	3.0	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
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
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
RICE - Natural Gas	0.0	0.0	0.0	0.0	0.0	8.0	29.0	2.0	19.5	0.0	0.0	10.5	0.0	0.0	0.0	0.0	18.9	20.9	19.9	5.2	39.8	0.0	0.0	0.0	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
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
Solar	77.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.3	5.1	6.8	137.2	98.9	44.4	59.8	172.1	300.8	332.9	285.3	559.0	1,660.0	807.5	1,019.8	136.8
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	0.0	0.0	0.0	0.0	1.1	0.0	0.0	0.0	0.0
Solar + Wind	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Steam - Coal	12.0	20.0	59.0	21.0	0.0	37.0	20.0	14.0	55.0	718.0	123.0	177.0	97.0	708.0	48.0	16.0	92.5	0.0	47.0	24.0	20.0	0.0	11.0	0.0	0.0
Steam - Natural Gas	0.0	0.0	2.5	10.0	0.0	0.0	0.0	0.0	25.0	145.0	0.0	0.0	5.5	0.0	0.0	0.0	0.0	696.5	0.0	0.0	0.0	64.0	0.0	0.0	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
Steam - Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	529.0	0.0	22.5	0.0	122.5	0.9	0.0	50.0	3.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
WInd	0.0	0.0	0.0	15.0	190.0	20.4	7.5	380.0	1,053.3	729.8	622.0	1,183.5	326.6	1,424.5	150.0	500.0	455.0	465.8	700.7	762.0	535.0	1,008.6	310.0	0.0	200.0
Wind + Storage	16.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	160.0	422.8	1,083.5	5,227.4	3,870.9	3,034.1	3,077.1	2,460.4	1,522.9	2,811.4	1,454.4	2,243.1	3,826.6	3,194.2	742.7	3,001.4	4,370.8	7,143.0	5,384.5	12,410.9	4,169.8	2,977.0	4,883.1	4,024.2	2,253.9

Queue Analysis by Fuel Group

The time it takes to complete a study depends on the backlog and the number of projects in the queue, but not on the size of the project. Table 12-27 shows the number of projects that entered the queue by year and by fuel group. The fuel groups are nuclear units, renewable units (including solar, hydro, biomass, renewable hybrid and wind) and traditional units (all other fuels). The number of queue entries has increased during the past several years, primarily by renewable projects. Of the 5,513 projects entered from January 2015 through June 2023, 4,149 projects (75.3 percent) were renewable. Of the 444 projects entered in the first six months of 2023, 399 projects (89.9 percent) were renewable.

Table 12-27 Number of projects entered in the queue: June 30, 2023

	Fuel Group						
Year Entered	Nuclear	Percent Nuclear	Renewable	Percent Renewable	Traditional	Percent Traditional	Total
1997	2	15.38%	0	0.00%	11	84.62%	13
1998	0	0.00%	0	0.00%	18	100.00%	18
1999	1	1.11%	5	5.56%	84	93.33%	90
2000	2	2.41%	3	3.61%	78	93.98%	83
2001	4	4.40%	6	6.59%	81	89.01%	91
2002	3	5.88%	15	29.41%	33	64.71%	51
2003	1	1.89%	34	64.15%	18	33.96%	53
2004	4	7.41%	17	31.48%	33	61.11%	54
2005	3	2.26%	75	56.39%	55	41.35%	133
2006	9	5.73%	67	42.68%	81	51.59%	157
2007	9	4.11%	65	29.68%	145	66.21%	219
2008	3	1.39%	102	47.22%	111	51.39%	216
2009	10	5.78%	107	61.85%	56	32.37%	173
2010	5	1.13%	370	83.90%	66	14.97%	441
2011	6	1.69%	264	74.37%	85	23.94%	355
2012	2	1.26%	59	37.11%	98	61.64%	159
2013	1	0.65%	54	35.06%	99	64.29%	154
2014	0	0.00%	100	52.08%	92	47.92%	192
2015	0	0.00%	134	43.37%	175	56.63%	309
2016	2	0.50%	298	74.69%	99	24.81%	399
2017	2	0.56%	293	82.54%	60	16.90%	355
2018	1	0.23%	344	78.18%	95	21.59%	440
2019	0	0.00%	548	78.62%	149	21.38%	697
2020	2	0.20%	781	78.34%	214	21.46%	997
2021	0	0.00%	983	73.63%	352	26.37%	1,335
2022	0	0.00%	369	68.72%	168	31.28%	537
2023	0	0.00%	399	89.86%	45	10.14%	444
Total	72	0.88%	5,492	67.26%	2,601	31.86%	8,165

As of June 30, 2023, renewable projects make up 77.6 percent of all projects in the queue and those projects account for 75.6 percent of the nameplate MW currently active, suspended or under construction in the queue as of June 30, 2023 (Table 12-28).

Table 12-28 Queue details by fuel group: June 30, 2023

Fuel Group	Number of Projects	Percent of Projects	MW	Percent MW
Nuclear	1	0.0%	44.0	0.0%
Renewable	2,734	77.6%	217,146.5	75.6%
Traditional	786	22.3%	69,894.3	24.3%
Total	3,521	100.0%	287,084.8	100.0%

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

While renewables currently make up the majority of both projects and nameplate MW in the queue, historical completion rates and derating factors must be accounted for when evaluating the share of capacity resources that are likely to be contributed by renewables (Table 12-24). Table 12-29 shows the total MW of all projects in the queue as of June 30, 2023, in the status of active, suspended and under construction, by unit type. Table 12-29 also shows the total MW for each fuel type adjusted based on current historical completion rates and for battery, solar and wind ELCC derates. Of the 9,191.4 MW of combined cycle projects in the queue, 5,377.4 MW (58.5 percent) are expected to go in service based on historical completion rates as of June 30, 2023. Of the 217,146.5 MW of renewable projects in the queue, only 32,536.9 MW (15.0 percent) are expected to go in service based on historical completion rates. Of the 217,146.5 MW of renewable projects in the queue, only 14,422.9 MW (6.6 percent) of capacity resources are expected to go into service, based on both historical completion rates and ELCC derate factors for battery, wind and solar.

Table 12-29 Queue totals for projects (active, suspended and under construction) by unit type adjusted based on current historical completion rates and ELCC battery, solar and wind derates (MW): June 30, 2023[62]

Unit Type	MW in Queue	Completion Rate Adjusted MW in Queue	Completion Rate and ELCC Adjusted MW in Queue
Battery	56,707.5	1,409.1	1,169.6
CC	9,191.4	5,377.4	5,377.4
CT - Natural Gas	3,829.2	2,646.0	2,646.0
CT - Oil	8.0	7.3	7.3
CT - Other	53.8	4.5	4.5
Fuel Cell	5.0	1.5	1.5
Hydro - Pumped Storage	730.0	707.2	707.2
Hydro - Run of River	112.8	52.3	52.3
Nuclear	44.0	22.6	22.6
RICE - Natural Gas	14.4	3.7	3.7
RICE - Oil	0.0	0.0	0.0
RICE - Other	0.0	0.0	0.0
Solar	129,431.3	22,804.6	12,314.5
Solar + Storage	37,589.0	4.3	2.3
Solar + Wind	209.0	0.0	0.0
Steam - Coal	65.0	23.1	23.1
Steam - Natural Gas	5.0	4.6	4.6
Steam - Oil	0.0	0.0	0.0
Steam - Other	20.0	5.4	5.4
Wind	48,919.5	8,967.0	1,345.0
Wind + Storage	150.0	0.0	0.0
Total	287,084.8	42,040.5	23,687.0

Queue Analysis by Unit Type and Project Classification

Table 12-30 shows the current status of all generation queue projects by unit type and project classification from January 1, 1997, through June 30, 2023. As of June 30, 2023, 8,165 projects, representing 827,797.5 MW, have entered the queue process since its inception. Of those, 1,101 projects, representing 85,750.0 MW, went into service. Of the projects that entered the queue process, 3,543 projects, representing 454,962.8 MW (55.0 percent of the MW) withdrew prior to completion. Such projects may create barriers to entry for projects that would otherwise be completed by taking up queue positions, increasing interconnection costs and creating uncertainty.

A total of 6,204 projects have been classified as new generation and 1,961 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 6,435 projects (78.8 percent) of all 8,165 generation queue projects to enter the queue since January 1, 1997.

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

Table 12-30 Status of all generation queue projects: January 1, 1997 through June 30, 2023

		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	23	67	50	10	25	3	0	10	2	10	0	55	219	1	0	8	5	0	4	99	0	591
	Upgrade	7	113	132	17	5	1	3	19	45	9	2	16	49	0	0	56	10	0	8	17	1	510
Under Construction	New Generation	4	0	1	0	0	0	0	0	0	0	0	0	48	3	0	0	1	0	0	1	0	58
	Upgrade	0	6	4	6	0	0	0	0	1	0	0	0	12	1	0	1	0	0	0	1	0	32
Suspended	New Generation	3	5	1	0	0	0	0	0	0	0	0	0	71	19	0	0	0	0	0	1	0	100
	Upgrade	0	0	0	0	0	0	0	0	0	0	0	0	2	2	0	0	0	0	0	0	0	4
Withdrawn	New Generation	232	436	30	10	83	26	2	44	9	29	12	16	1,562	102	0	55	1	0	34	476	1	3,160
	Upgrade	67	105	20	15	13	2	0	5	15	0	3	3	83	2	0	15	2	0	2	31	0	383
Active	New Generation	421	5	4	0	5	0	2	5	0	1	0	0	1,380	373	2	0	0	0	1	95	1	2,295
	Upgrade	271	18	24	0	2	2	1	2	0	0	0	0	559	52	1	2	0	0	0	97	1	1,032
Total Projects	New Generation	683	513	86	20	113	29	4	59	11	40	12	71	3,280	498	2	63	7	0	39	672	2	6,204
	Upgrade	345	242	180	38	20	5	4	26	61	9	5	19	705	57	1	74	12	0	10	146	2	1,961

Table 12-31 shows the totals in Table 12-30 by share of classification as new generation or upgrade. Within a unit type the shares of upgrades add to 100 percent and the shares of new generation add to 100 percent. For example, 70.9 percent of all hydro run of river projects classified as upgrades are currently in service in PJM, 19.2 percent of hydro run of river upgrades were withdrawn and 9.9 percent of hydro run of river upgrades are active in the queue.

Table 12-31 Status of all generation queue projects as a percent of total projects by classification: January 1, 1997 through June 30, 2023

		Percent of Projects																					
Project Status	Project Classification	Battery	CC	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
In Service	New Generation	3.4%	13.1%	58.1%	50.0%	22.1%	10.3%	0.0%	16.9%	18.2%	25.0%	0.0%	77.5%	6.7%	0.2%	0.0%	12.7%	71.4%	0.0%	10.3%	14.7%	0.0%	9.5%
	Upgrade	2.0%	46.7%	73.3%	44.7%	25.0%	20.0%	75.0%	73.1%	73.8%	100.0%	40.0%	84.2%	7.0%	0.0%	0.0%	75.7%	83.3%	0.0%	80.0%	11.6%	50.0%	26.0%
Under Construction	New Generation	0.6%	0.0%	1.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.5%	0.6%	0.0%	0.0%	14.3%	0.0%	0.0%	0.1%	0.0%	0.9%
	Upgrade	0.0%	2.5%	2.2%	15.8%	0.0%	0.0%	0.0%	0.0%	1.6%	0.0%	0.0%	0.0%	1.7%	1.8%	0.0%	1.4%	0.0%	0.0%	0.0%	0.7%	0.0%	1.6%
Suspended	New Generation	0.4%	1.0%	1.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	2.2%	3.8%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.0%	1.6%
	Upgrade	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.3%	3.5%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%
Withdrawn	New Generation	34.0%	85.0%	34.9%	50.0%	73.5%	89.7%	50.0%	74.6%	81.8%	72.5%	100.0%	22.5%	47.6%	20.5%	0.0%	87.3%	14.3%	0.0%	87.2%	70.8%	50.0%	50.9%
	Upgrade	19.4%	43.4%	11.1%	39.5%	65.0%	40.0%	0.0%	19.2%	24.6%	0.0%	60.0%	15.8%	11.8%	3.5%	0.0%	20.3%	16.7%	0.0%	20.0%	21.2%	0.0%	19.5%
Active	New Generation	61.6%	1.0%	4.7%	0.0%	4.4%	0.0%	50.0%	8.5%	0.0%	2.5%	0.0%	0.0%	42.1%	74.9%	100.0%	0.0%	0.0%	0.0%	2.6%	14.1%	50.0%	37.0%
	Upgrade	78.6%	7.4%	13.3%	0.0%	10.0%	40.0%	25.0%	7.7%	0.0%	0.0%	0.0%	0.0%	79.3%	91.2%	100.0%	2.7%	0.0%	0.0%	0.0%	66.4%	50.0%	52.6%

Table 12-32 shows the total MW of projects in the PJM generation queue by unit type and project classification. For example, the 476 new generation wind projects that have been withdrawn from the queue as of June 30, 203, (as shown in Table 12-30) constitute 87,651.6 MW. The 436 new generation combined cycle projects that have been withdrawn in the same time period constitute 219,816.7 MW.

Table 12-32 Status of all generation (MW) in the generation queue: January 1, 1997 through June 30, 2023

Project Status	Project Classification	Project MW: Battery	CC	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
In Service	New Generation	223.9	39,701.9	6,722.8	676.5	149.2	1.9	0.0	371.5	1,639.0	156.4	0.0	440.1	5,204.7	1.1	0.0	1,343.0	723.0	0.0	60.9	10,801.0	0.0	68,217.0
	Upgrade	44.4	8,346.5	3,132.1	132.8	12.3	3.0	390.0	387.6	2,365.0	17.3	27.3	47.5	502.4	0.0	0.0	976.5	225.5	0.0	667.8	238.7	16.3	17,533.0
Under Construction	New Generation	35.0	0.0	18.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3,354.8	19.6	0.0	0.0	5.0	0.0	0.0	100.8	0.0	3,533.2
	Upgrade	0.0	350.4	14.0	8.0	0.0	0.0	0.0	0.0	44.0	0.0	0.0	0.0	174.1	3.2	0.0	36.0	0.0	0.0	0.0	87.6	0.0	717.3
Suspended	New Generation	27.0	3,950.0	675.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3,398.3	264.1	0.0	0.0	0.0	0.0	0.0	80.0	0.0	8,394.4
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	26.9	150.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	176.9
Withdrawn	New Generation	8,845.7	219,816.7	4,889.3	1,735.0	1,583.3	5.5	500.0	2,066.5	8,161.0	481.2	63.9	88.6	51,975.7	10,014.8	0.0	33,511.6	27.0	0.0	1,050.9	87,651.6	90.0	432,558.2
	Upgrade	1,523.9	13,455.0	1,093.0	593.0	72.5	0.9	0.0	105.1	1,066.0	0.0	19.6	10.0	1,890.3	3.7	0.0	885.0	6.0	0.0	37.1	1,643.4	0.0	22,404.5
Active	New Generation	46,221.6	4,171.0	2,068.0	0.0	53.8	0.0	700.0	58.6	0.0	14.4	0.0	0.0	111,265.1	35,736.8	209.0	0.0	0.0	0.0	20.0	44,412.4	150.0	245,080.6
	Upgrade	10,423.9	720.0	1,054.2	0.0	0.0	5.0	30.0	54.2	0.0	0.0	0.0	0.0	11,212.1	1,415.3	0.0	29.0	0.0	0.0	0.0	4,238.7	0.0	29,182.4
Total Projects	New Generation	55,353.2	267,639.6	14,373.1	2,411.5	1,786.4	7.4	1,200.0	2,496.5	9,800.0	652.0	63.9	528.7	175,198.6	46,036.4	209.0	34,854.6	755.0	0.0	1,131.8	143,045.8	240.0	757,783.4
	Upgrade	11,992.2	22,871.9	5,293.3	733.8	84.8	8.9	420.0	546.9	3,475.0	17.3	46.9	57.5	13,805.8	1,572.2	0.0	1,926.5	231.5	0.0	704.9	6,208.4	16.3	70,014.2

Table 12-33 shows the MW totals in Table 12-32 by share by classification as new generation or upgrade. Within a unit type the shares of upgrades add to 100 percent and the shares of new generation add to 100 percent. For example, 61.3 percent of wind project MW classified as new generation have been withdrawn from the queue between January 1, 1997, and June 30, 2023.

Table 12-33 Status of all generation queue projects as percent of total MW in project classification: January 1, 1997 through June 30, 2023

Project Status	Project Classification	Percent of Total Projects by Classification: Battery	CC	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
In Service	New Generation	0.4%	14.8%	46.8%	28.1%	8.4%	26.2%	0.0%	14.9%	16.7%	24.0%	0.0%	83.2%	3.0%	0.0%	0.0%	3.9%	95.8%	0.0%	5.4%	7.6%	0.0%	9.0%
	Upgrade	0.4%	36.5%	59.2%	18.1%	14.5%	33.5%	92.9%	70.9%	68.1%	100.0%	58.2%	82.6%	3.6%	0.0%	0.0%	50.7%	97.4%	0.0%	94.7%	3.8%	100.0%	25.0%
Under Construction	New Generation	0.1%	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.9%	0.0%	0.0%	0.0%	0.7%	0.0%	0.0%	0.1%	0.0%	0.5%
	Upgrade	0.0%	1.5%	0.3%	1.1%	0.0%	0.0%	0.0%	0.0%	1.3%	0.0%	0.0%	0.0%	1.3%	0.2%	0.0%	1.9%	0.0%	0.0%	0.0%	1.4%	0.0%	1.0%
Suspended	New Generation	0.0%	1.5%	4.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.9%	0.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.0%	1.1%
	Upgrade	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%	9.5%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.3%
Withdrawn	New Generation	16.0%	82.1%	34.0%	71.9%	88.6%	73.8%	41.7%	82.8%	83.3%	73.8%	100.0%	16.8%	29.7%	21.8%	0.0%	96.1%	3.6%	0.0%	92.9%	61.3%	37.5%	57.1%
	Upgrade	12.7%	58.8%	20.6%	80.8%	85.5%	10.6%	0.0%	19.2%	30.7%	0.0%	41.8%	17.4%	13.7%	0.2%	0.0%	45.9%	2.6%	0.0%	5.3%	26.5%	0.0%	32.0%
Active	New Generation	83.5%	1.6%	14.4%	0.0%	3.0%	0.0%	58.3%	2.3%	0.0%	2.2%	0.0%	0.0%	63.5%	77.6%	100.0%	0.0%	0.0%	0.0%	1.8%	31.0%	62.5%	32.3%
	Upgrade	86.9%	3.1%	19.9%	0.0%	0.0%	55.9%	7.1%	9.9%	0.0%	0.0%	0.0%	0.0%	81.2%	90.0%	0.0%	1.5%	0.0%	0.0%	0.0%	68.3%	0.0%	41.7%

Table 12-34 shows the project MW that entered the PJM generation queue by unit type and year of entry. Since 2016, 71.8 percent of all new projects entering the generation queue have been combined cycle (10.1 percent), wind (18.1 percent) or solar projects (43.6 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 June 30, 2023, 48,073.9 MW of renewable hybrid units have entered the queue.

Table 12-34 Queue project MW by unit type and queue entry year: January 1, 1997 through June 30, 2023

Year	Battery	CC	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
1997	0.0	4,148.0	321.0	315.0	0.0	0.0	0.0	0.0	50.0	0.0	0.0	0.0	0.0	0.0	0.0	6.0	0.0	0.0	0.0	0.0	0.0	4,840.0
1998	0.0	7,006.0	1,775.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8,781.0
1999	0.0	29,412.7	2,061.1	0.0	10.0	0.0	0.0	196.0	45.0	0.0	0.0	0.0	0.0	0.0	0.0	47.0	0.0	0.0	525.0	115.4	0.0	32,412.2
2000	0.0	21,144.8	493.6	31.5	8.8	0.0	0.0	0.0	95.0	0.0	0.0	1.2	0.0	0.0	0.0	37.0	2.5	0.0	0.0	95.6	0.0	21,909.9
2001	0.0	25,411.7	264.0	0.0	0.0	0.0	0.0	107.0	90.0	0.0	0.0	15.6	0.0	0.0	0.0	1,244.6	10.0	0.0	0.0	234.9	0.0	27,377.8
2002	0.0	4,154.0	11.7	0.0	70.5	0.0	0.0	293.0	236.0	8.0	23.3	4.5	0.0	0.0	0.0	1,895.0	0.0	0.0	0.0	790.9	0.0	7,486.9
2003	0.0	2,361.4	10.0	8.0	0.8	0.0	0.0	2.0	0.0	29.0	0.0	27.5	0.0	0.0	0.0	522.0	0.0	0.0	165.0	997.0	0.0	4,122.7
2004	0.0	3,610.0	43.3	20.0	49.1	0.0	0.0	0.0	1,911.0	0.0	35.5	17.5	0.0	0.0	0.0	1,187.0	0.0	0.0	0.0	1,614.7	0.0	8,488.1
2005	0.0	5,824.6	961.0	281.0	51.4	0.0	340.0	174.2	242.0	21.5	0.0	65.1	0.0	0.0	0.0	6,360.0	0.0	0.0	24.0	6,020.0	0.0	20,364.9
2006	0.0	4,188.1	454.3	607.5	73.1	0.0	0.0	159.0	6,894.0	0.0	0.0	93.0	0.0	0.0	0.0	9,586.0	0.0	0.0	258.5	7,650.7	0.0	29,964.2
2007	0.0	13,944.6	941.2	215.9	149.5	0.0	16.0	161.6	368.0	0.0	0.0	56.5	3.3	0.0	0.0	9,078.0	190.0	0.0	50.5	18,525.6	0.0	43,700.6
2008	121.0	26,001.0	129.7	1,113.0	488.8	0.0	0.0	1,254.5	105.0	6.0	0.0	32.0	66.3	0.0	0.0	1,198.0	0.0	0.0	192.3	10,955.5	0.0	41,663.1
2009	34.0	5,548.4	14.0	66.0	214.2	0.0	0.0	133.9	1,933.8	4.5	16.0	15.2	636.5	0.0	0.0	1,273.0	5.5	0.0	148.0	6,672.6	0.0	16,715.6
2010	72.4	9,185.4	176.0	7.9	117.3	0.0	0.0	132.6	426.0	0.0	2.4	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	1,589.0	0.0	0.0	1,730.5	27.0	0.0	43.1	1,691.3	0.0	19,099.6
2015	546.9	27,550.8	1,324.5	0.0	0.9	2.3	34.0	0.0	0.0	320.4	13.0	31.4	2,920.7	2.0	0.0	47.0	606.5	0.0	0.0	2,160.6	0.0	35,560.9
2016	111.1	18,802.5	1,392.0	0.0	0.0	3.4	0.0	12.5	59.0	23.5	0.0	38.9	11,548.5	85.6	0.0	80.0	77.0	0.0	0.0	3,448.7	16.3	35,698.9
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	13,631.8	424.9	0.0	14.0	17.0	0.0	0.0	5,137.0	90.0	25,705.3
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	20,185.0	4,107.9	0.0	49.0	0.0	0.0	0.0	17,695.2	0.0	57,788.6
2019	5,272.2	3,332.5	1,587.1	13.0	0.0	3.0	500.0	99.0	0.0	0.0	0.0	0.0	29,745.4	7,631.9	0.0	11.0	0.0	0.0	0.0	11,405.4	0.0	59,600.4
2020	11,448.9	50.0	846.6	4.0	0.0	0.0	0.0	80.2	100.0	0.0	0.0	0.0	37,465.4	10,014.1	199.0	0.0	11.0	0.0	0.0	6,881.9	0.0	67,101.2
2021	25,907.1	2,129.0	771.0	0.0	392.9	5.0	30.0	23.5	0.0	14.4	0.0	0.0	49,138.7	14,871.2	10.0	0.0	0.0	0.0	20.0	11,160.0	0.0	104,472.8
2022	17,528.0	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	9,643.5	0.0	0.0	0.0	0.0	0.0	14,214.3	150.0	56,747.2
2023	4,234.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	878.0	827.5	0.0	0.0	0.0	0.0	0.0	3,580.9	0.0	9,520.8
Total	67,345.4	290,511.5	19,666.4	3,145.3	1,871.1	16.3	1,620.0	3,043.4	13,275.0	669.3	110.8	586.2	189,004.4	47,608.6	209.0	36,781.1	986.5	0.0	1,836.7	149,254.2	256.3	827,797.5

Combined Cycle Project Analysis

Table 12-35 shows the status of all combined cycle projects by number of projects that entered PJM generation queues from January 1, 1997, through June 30, 2023, by zone. Of the 34 combined cycle projects classified as new generation or upgrade currently active, suspended or under construction in the PJM generation queue, nine projects (26.5 percent) are located in the APS Zone.

Table 12-35 Status of all combined cycle queue projects by zone (number of projects): January 1, 1997 through June 30, 2023

		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	15	0	9	5	0	6	0	0	0	16	5	0	6	4	0	13	3	4	10	14	0	113
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	1	0	1	0	0	1	0	0	0	0	0	0	0	1	0	0	0	0	1	1	0	6
Suspended	New Generation	0	2	0	1	1	0	1	0	0	0	0	0	0	0	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	20	0	45	13	8	16	1	1	2	18	16	3	26	25	0	44	41	35	42	55	2	436
	Upgrade	8	8	0	10	4	0	4	0	1	0	11	6	0	8	7	0	3	7	5	8	15	0	105
Active	New Generation	0	0	0	4	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	5
	Upgrade	0	1	0	3	1	0	0	0	0	0	7	0	0	0	0	0	1	1	2	1	1	0	18
Total Projects	New Generation	24	29	0	53	19	10	20	1	3	2	25	18	3	33	29	0	49	43	39	51	60	2	513
	Upgrade	11	25	0	23	10	0	11	0	1	0	34	11	0	14	12	0	17	11	11	20	31	0	242

Table 12-36 shows the status of all combined cycle projects by MW that entered PJM generation queues from January 1, 1997, through June 30, 2023, by zone. Of the 9,191.4 MW of combined cycle projects classified as new generation or upgrade currently active, suspended or under construction in the PJM generation queue, 4,700.0 MW (51.1 percent) are located in the APS Zone.

Table 12-36 Status of all combined cycle queue projects by zone (MW): January 1, 1997 through June 30, 2023

		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	1,250.0	0.0	939.7	344.0	0.0	642.6	0.0	0.0	0.0	978.0	102.0	0.0	110.0	113.9	0.0	1,075.5	112.3	228.6	1,375.0	845.9	0.0	8,346.5
Under Construction	New Generation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	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	50.0	0.0	20.0	0.0	0.0	102.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	75.0	0.0	0.0	0.0	0.0	51.6	51.1	0.0	350.4
Suspended	New Generation	0.0	1,150.0	0.0	1,270.0	955.0	0.0	575.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3,950.0
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Withdrawn	New Generation	8,542.4	13,559.5	0.0	21,832.1	8,641.0	3,122.1	10,817.0	1,150.0	134.5	665.0	12,961.0	5,145.4	991.8	13,562.6	13,001.0	0.0	24,140.0	16,114.0	22,268.2	18,917.7	24,244.6	6.9	219,816.7
	Upgrade	157.0	746.0	0.0	1,284.0	636.0	0.0	1,735.0	0.0	36.0	0.0	780.4	1,410.0	0.0	413.0	1,742.0	0.0	240.0	1,125.6	229.1	703.0	2,217.9	0.0	13,455.0
Active	New Generation	0.0	0.0	0.0	3,231.0	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	4,171.0
	Upgrade	0.0	285.0	0.0	179.0	58.0	0.0	0.0	0.0	0.0	0.0	118.0	0.0	0.0	0.0	0.0	0.0	5.0	30.0	45.0	0.0	0.0	0.0	720.0
Total Projects	New Generation	9,192.4	20,320.5	0.0	28,303.1	14,287.0	3,262.1	14,352.9	1,150.0	667.5	665.0	18,789.6	5,464.6	991.8	15,228.4	15,558.0	0.0	26,805.0	18,014.0	23,828.2	24,809.7	25,943.1	6.9	267,639.6
	Upgrade	386.0	2,331.0	0.0	2,422.7	1,038.0	0.0	2,480.3	0.0	36.0	0.0	1,876.4	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	22,871.9

Of the 34 combined cycle units in the queue as of June 30, 2023, in the status of Active, Under Construction or Suspended, 15 units, representing 2,004.7 MW had a projected in service date prior to January 1, 2023 and 19 units, representing 7,186.7 MW had a projected in service date between January 1, 2023, and November 2, 2026.

Combustion Turbine - Natural Gas Project Analysis

Table 12-37 shows the status of all combustion turbine natural gas projects by number of projects that entered PJM generation queues from January 1, 1997, through June 30, 2023, by zone. Of the 34 combustion turbine natural gas projects classified as new generation or upgrade currently active, suspended or under construction in the PJM generation queue, 10 projects (29.4 percent) are located in the DOM Zone.

Table 12-37 Status of all combustion turbine - natural gas generation queue projects by zone (number of projects): January 1, 1997 through June 30, 2023

		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	2	3	6	0	2	1	0	2	4	2	4	9	0	50
	Upgrade	4	11	0	10	5	0	19	6	0	0	28	8	0	5	2	0	4	7	5	4	14	0	132
Under Construction	New Generation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	1
	Upgrade	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3	0	0	1	0	0	0	0	4
Suspended	New Generation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	1
	Upgrade	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Withdrawn	New Generation	1	6	0	0	0	2	1	1	0	0	4	0	1	1	0	0	1	6	0	1	5	0	30
	Upgrade	2	1	0	1	1	0	3	2	0	2	3	0	0	0	1	0	0	2	2	0	0	0	20
Active	New Generation	1	1	0	0	0	0	0	0	0	0	2	0	0	0	0	0	0	0	0	0	0	0	4
	Upgrade	2	2	0	1	4	0	5	1	0	0	8	0	0	0	0	0	0	0	1	0	0	0	24
Total Projects	New Generation	7	7	0	6	0	5	2	1	0	2	9	6	1	3	1	0	3	11	2	5	15	0	86
	Upgrade	8	14	0	12	10	0	27	9	0	2	39	8	0	5	6	0	4	10	8	4	14	0	180

Table 12-38 shows the status of all combustion turbine natural gas projects by MW that entered PJM generation queues from January 1, 1997, through June 30, 2023, by zone. Of the 3,829.2 MW of combustion turbine natural gas projects classified as new generation or upgrade currently active, suspended or under construction in the PJM generation queue, 1,138.0 MW (29.7 percent) are located in the DOM Zone.

Table 12-38 Status of all combustion turbine - natural gas queue projects by zone (MW): January 1, 1997 through June 30, 2023

		Project MW																						
Project Status	Project Classification	ACEC	AEP	AMPT	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
In Service	New Generation	360.7	0.0	0.0	1,176.0	0.0	23.0	190.0	0.0	0.0	219.4	1,081.0	1,140.0	0.0	520.0	10.0	0.0	559.0	361.9	5.0	150.9	925.9	0.0	6,722.8
	Upgrade	43.7	278.1	0.0	269.7	105.0	0.0	698.0	83.5	0.0	0.0	925.7	86.0	0.0	20.0	36.1	0.0	42.0	38.0	39.0	252.3	215.0	0.0	3,132.1
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	18.0	0.0	0.0	0.0	0.0	18.0
	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	11.5	0.0	0.0	2.5	0.0	0.0	0.0	0.0	14.0
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	675.0	0.0	675.0
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Withdrawn	New Generation	7.5	1,519.0	0.0	0.0	0.0	153.6	10.0	104.0	0.0	0.0	1,069.8	0.0	73.0	2.1	0.0	0.0	0.5	789.8	0.0	19.9	1,140.1	0.0	4,889.3
	Upgrade	165.5	6.0	0.0	4.0	25.0	0.0	373.0	104.0	0.0	18.5	57.0	0.0	0.0	0.0	0.0	0.0	0.0	327.0	13.0	0.0	0.0	0.0	1,093.0
Active	New Generation	230.0	700.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,138.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,068.0
	Upgrade	0.0	91.0	0.0	30.0	458.7	0.0	419.2	20.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	35.3	0.0	0.0	0.0	1,054.2
Total Projects	New Generation	598.2	2,219.0	0.0	1,176.0	0.0	176.6	200.0	104.0	0.0	219.4	3,288.8	1,140.0	73.0	522.1	10.0	0.0	559.5	1,169.7	5.0	170.8	2,741.0	0.0	14,373.1
	Upgrade	209.2	375.1	0.0	303.7	588.7	0.0	1,490.2	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	5,293.3

Wind Project Analysis

Table 12-39 shows the status of all wind generation projects, by number of projects that entered PJM generation queues from January 1, 1997, through June 30, 2023, by zone. Of the 195 wind projects classified as new generation or upgrade currently active, suspended or under construction in the PJM generation queue, 73 projects (37.4 percent) are located in the COMED Zone.

Table 12-39 Status of all wind generation queue projects by zone (number of projects): January 1, 1997 through June 30, 2023

		Number of Projects																						
Project Status	Project Classification	ACEC	AEP	AMPT	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
In Service	New Generation	1	19	0	18	0	0	27	0	0	0	3	0	0	0	0	0	0	23	0	8	0	0	99
	Upgrade	0	0	0	3	0	0	9	0	0	0	0	0	0	0	0	0	0	5	0	0	0	0	17
Under Construction	New Generation	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
	Upgrade	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	1
Suspended	New Generation	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
	Upgrade	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Withdrawn	New Generation	19	120	0	46	10	0	110	15	0	0	21	13	1	7	0	0	0	63	0	50	1	0	476
	Upgrade	2	2	0	7	0	0	8	0	0	0	3	1	0	0	0	0	0	6	0	2	0	0	31
Active	New Generation	5	14	0	6	1	0	34	1	0	0	8	9	0	11	0	0	0	3	0	1	2	0	95
	Upgrade	2	21	0	10	1	0	38	0	0	0	2	4	0	9	0	0	0	10	0	0	0	0	97
Total Projects	New Generation	25	153	0	71	11	0	172	16	0	0	32	22	1	18	0	0	0	89	0	59	3	0	672
	Upgrade	4	23	0	20	1	0	55	0	0	0	5	5	0	9	0	0	0	22	0	2	0	0	146

Table 12-40 shows the status of all wind projects by MW that entered PJM generation queues from January 1, 1997, through June 30, 2023, by zone. Of the 48,919.5 MW of wind projects classified as new generation or upgrade currently active, suspended or under construction in the PJM generation queue, 16,390.1 MW (33.5 percent) are located in the JCPLC Zone.

Table 12-40 Status of all wind generation queue projects by zone (MW): January 1, 1997 through June 30, 2023

		Project MW																						
Project Status	Project Classification	ACEC	AEP	AMPT	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
In Service	New Generation	7.5	3,544.6	0.0	1,364.0	0.0	0.0	4,288.9	0.0	0.0	0.0	322.5	0.0	0.0	0.0	0.0	0.0	0.0	1,047.0	0.0	226.5	0.0	0.0	10,801.0
	Upgrade	0.0	0.0	0.0	5.0	0.0	0.0	213.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20.5	0.0	0.0	0.0	0.0	238.7
Under Construction	New Generation	0.0	0.0	0.0	0.0	0.0	0.0	100.8	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	100.8
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	87.6	0.0	0.0	0.0	0.0	87.6
Suspended	New Generation	0.0	0.0	0.0	80.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	80.0
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Withdrawn	New Generation	4,943.6	24,731.4	0.0	3,552.2	1,814.0	0.0	25,593.9	2,128.0	0.0	0.0	4,988.4	3,240.8	150.3	7,397.0	0.0	0.0	0.0	5,257.0	0.0	3,835.2	20.0	0.0	87,651.6
	Upgrade	5.0	370.0	0.0	119.4	0.0	0.0	755.7	0.0	0.0	0.0	114.0	30.0	0.0	0.0	0.0	0.0	0.0	243.4	0.0	6.0	0.0	0.0	1,643.4
Active	New Generation	3,141.6	2,538.3	0.0	741.5	297.7	0.0	8,789.9	100.0	0.0	0.0	5,307.5	6,414.2	0.0	14,060.1	0.0	0.0	0.0	236.9	0.0	174.8	2,610.0	0.0	44,412.4
	Upgrade	0.0	12.6	0.0	207.6	0.0	0.0	483.4	0.0	0.0	0.0	0.0	955.3	0.0	2,330.0	0.0	0.0	0.0	249.8	0.0	0.0	0.0	0.0	4,238.7
Total Projects	New Generation	8,092.7	30,814.3	0.0	5,737.7	2,111.7	0.0	38,773.5	2,228.0	0.0	0.0	10,618.4	9,655.0	150.3	21,457.1	0.0	0.0	0.0	6,540.8	0.0	4,236.5	2,630.0	0.0	143,045.8
	Upgrade	5.0	382.6	0.0	332.0	0.0	0.0	1,452.2	0.0	0.0	0.0	114.0	985.3	0.0	2,330.0	0.0	0.0	0.0	601.3	0.0	6.0	0.0	0.0	6,208.4

Solar Project Analysis

Table 12-41 shows the status of all solar generation projects by number of projects that entered PJM generation queues from January 1, 1997, through June 30, 2023, by zone. Of the 2,072 solar projects classified as new generation or upgrade currently active, suspended or under construction in the PJM generation queue, 478 projects (23.1 percent) are located in the AEP Zone.

Table 12-41 Status of all solar generation queue projects by zone (number of projects): January 1, 1997 through June 30, 2023

		Number of Projects																						
Project Status	Project Classification	ACEC	AEP	AMPT	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
In Service	New Generation	10	12	0	10	0	1	1	1	1	0	56	18	1	54	0	0	1	3	2	2	46	0	219
	Upgrade	2	5	0	3	0	0	0	0	2	0	12	10	0	11	0	0	0	1	0	3	0	0	49
Under Construction	New Generation	1	5	0	3	3	0	1	5	1	3	17	1	0	0	3	0	0	1	0	1	3	0	48
	Upgrade	0	0	0	0	1	0	1	0	1	1	4	0	0	0	0	0	0	0	0	0	4	0	12
Suspended	New Generation	1	7	0	16	5	0	4	3	0	0	14	0	1	0	5	0	0	7	0	7	1	0	71
	Upgrade	0	0	0	1	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	2
Withdrawn	New Generation	192	139	0	106	37	15	51	27	16	2	269	159	17	199	32	1	11	81	25	62	121	0	1,562
	Upgrade	4	6	0	4	5	0	6	1	0	0	26	3	0	9	3	0	0	10	3	0	3	0	83
Active	New Generation	20	287	1	128	81	5	74	27	9	3	304	52	68	32	33	2	10	159	9	73	3	0	1,380
	Upgrade	6	179	1	38	35	0	38	23	2	1	79	21	19	9	15	3	0	47	0	41	2	0	559
Total Projects	New Generation	224	450	1	263	126	21	131	63	27	8	660	230	87	285	73	3	22	251	36	145	174	0	3,280
	Upgrade	12	190	1	46	41	0	45	24	5	2	121	34	19	30	18	3	0	58	3	44	9	0	705

Table 12-42 shows the status of all solar projects by MW that entered PJM generation queues from January 1, 1997, through June 30, 2023, by zone. Of the 129,431.3 MW of solar projects classified as new generation or upgrade currently active, suspended or under construction in the PJM generation queue, 45,306.4 MW (35.0 percent) are located in the AEP Zone.

Table 12-42 Status of all solar generation queue projects by zone (MW): January 1, 1997 through June 30, 2023

		Project MW																						
Project Status	Project Classification	ACEC	AEP	AMPT	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
In Service	New Generation	65.0	694.2	0.0	140.5	0.0	1.1	9.0	2.5	125.0	0.0	3,075.2	280.9	50.0	417.7	0.0	0.0	3.3	53.5	30.0	15.0	241.9	0.0	5,204.7
	Upgrade	0.0	317.0	0.0	0.0	0.0	0.0	0.0	0.0	75.0	0.0	86.1	0.0	0.0	14.3	0.0	0.0	0.0	0.0	0.0	10.0	0.0	0.0	502.4
Under Construction	New Generation	2.6	365.7	0.0	93.8	423.0	0.0	50.0	599.6	70.0	45.9	1,356.7	150.0	0.0	0.0	60.0	0.0	0.0	100.0	0.0	20.0	17.5	0.0	3,354.8
	Upgrade	0.0	0.0	0.0	0.0	20.0	0.0	50.0	0.0	10.0	8.3	82.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.8	0.0	174.1
Suspended	New Generation	49.7	475.0	0.0	349.1	445.0	0.0	102.5	327.9	0.0	0.0	1,136.9	0.0	95.0	0.0	67.0	0.0	0.0	184.2	0.0	146.2	19.9	0.0	3,398.3
	Upgrade	0.0	0.0	0.0	15.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	11.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	26.9
Withdrawn	New Generation	2,120.2	9,635.4	0.0	3,055.2	1,943.7	121.6	4,074.2	2,324.6	689.4	33.0	16,528.9	2,741.3	1,010.9	1,624.3	1,050.0	78.0	114.2	2,730.6	440.0	1,090.1	570.3	0.0	51,975.7
	Upgrade	172.5	126.0	0.0	32.9	213.0	0.0	110.0	20.0	0.0	0.0	1,113.6	5.0	0.0	23.8	15.0	0.0	0.0	53.7	3.6	0.0	1.3	0.0	1,890.3
Active	New Generation	523.0	40,342.5	40.0	5,588.4	5,229.3	154.9	11,578.4	2,405.4	578.9	34.7	27,167.4	1,949.8	6,466.2	688.2	503.1	340.0	129.4	5,150.4	210.7	2,166.4	18.0	0.0	111,265.1
	Upgrade	48.0	4,123.2	166.0	554.4	730.7	0.0	1,687.0	275.5	20.0	0.0	1,974.6	74.0	333.8	16.4	193.0	90.0	0.0	585.5	0.0	340.1	0.0	0.0	11,212.1
Total Projects	New Generation	2,760.5	51,512.8	40.0	9,226.9	8,041.0	277.6	15,814.1	5,659.9	1,463.3	113.6	49,265.1	5,122.1	7,622.1	2,730.2	1,680.1	418.0	246.9	8,218.6	680.7	3,437.7	867.6	0.0	175,198.6
	Upgrade	220.5	4,566.2	166.0	603.1	963.7	0.0	1,847.0	295.5	105.0	8.3	3,256.3	78.9	333.8	65.5	208.0	90.0	0.0	639.2	3.6	350.1	5.1	0.0	13,805.8

Battery Project Analysis

Table 12-43 shows the status of all battery generation projects by number of projects that entered PJM generation queues from January 1, 1997, through June 30, 2023, by zone. Of the 699 battery projects currently active, suspended or under construction in the PJM generation queue, 239 projects (34.2 percent) are located in the DOM Zone.

Table 12-43 Status of all battery generation queue projects by zone (number of projects): January 1, 1997 through June 30, 2023

		Number of Projects																						
Project Status	Project Classification	ACEC	AEP	AMPT	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
In Service	New Generation	0	2	0	3	0	0	7	1	4	0	0	0	0	2	0	0	1	0	0	1	2	0	23
	Upgrade	0	1	0	0	0	0	0	1	1	0	0	0	0	2	0	0	0	2	0	0	0	0	7
Under Construction	New Generation	0	0	0	0	0	1	0	0	0	0	1	0	0	2	0	0	0	0	0	0	0	0	4
	Upgrade	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Suspended	New Generation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	2	0	3
	Upgrade	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Withdrawn	New Generation	8	33	0	4	7	25	28	3	3	1	38	17	1	38	4	0	4	4	1	7	6	0	232
	Upgrade	4	9	0	8	2	0	6	2	1	0	10	2	0	7	3	0	3	7	0	3	0	0	67
Active	New Generation	16	74	0	20	14	10	45	1	3	5	151	16	5	20	6	0	0	11	7	7	10	0	421
	Upgrade	6	53	1	18	10	1	49	4	1	0	87	9	3	5	4	0	0	17	0	2	1	0	271
Total Projects	New Generation	24	109	0	27	21	36	80	5	10	6	190	33	6	62	10	0	5	15	8	16	20	0	683
	Upgrade	10	63	1	26	12	1	55	7	3	0	97	11	3	14	7	0	3	26	0	5	1	0	345

Table 12-44 shows the status of all battery projects by MW that entered PJM generation queues from January 1, 1997, through June 30, 2023, by zone. Of the 56,707.5 MW of battery generation currently active, suspended or under construction in the PJM generation queue, 16,108.2 MW (28.4 percent) are located in the DOM Zone.

Table 12-44 Status of all battery generation queue projects by zone (MW): January 1, 1997 through June 30, 2023

		Project MW																						
Project Status	Project Classification	ACEC	AEP	AMPT	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
In Service	New Generation	0.0	6.0	0.0	39.9	0.0	0.0	86.0	12.0	16.0	0.0	0.0	0.0	0.0	40.0	0.0	0.0	1.0	0.0	0.0	20.0	3.0	0.0	223.9
	Upgrade	0.0	4.0	0.0	0.0	0.0	0.0	0.0	8.0	4.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	28.4	0.0	0.0	0.0	0.0	44.4
Under Construction	New Generation	0.0	0.0	0.0	0.0	0.0	1.0	0.0	0.0	0.0	0.0	20.0	0.0	0.0	14.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	35.0
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Suspended	New Generation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20.0	7.0	0.0	27.0
	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	166.5	1,419.0	0.0	187.0	206.1	260.6	1,680.0	319.9	75.5	20.0	2,188.4	350.0	20.3	874.1	214.7	0.0	4.3	360.0	20.0	299.8	179.5	0.0	8,845.7
	Upgrade	20.0	302.2	0.0	209.0	20.3	0.0	335.3	95.0	20.0	0.0	183.0	14.0	0.0	55.1	149.0	0.0	60.0	41.0	0.0	20.0	0.0	0.0	1,523.9
Active	New Generation	1,924.2	8,591.5	0.0	1,878.2	2,010.0	1,342.5	7,277.2	85.0	475.0	505.0	14,179.2	909.0	176.0	1,478.8	526.2	0.0	0.0	1,005.8	1,918.0	380.0	1,560.0	0.0	46,221.6
	Upgrade	0.0	2,784.4	0.0	1,553.3	408.0	115.0	2,441.0	205.0	52.2	0.0	1,909.0	155.0	0.0	94.0	310.0	0.0	0.0	362.0	0.0	20.0	15.0	0.0	10,423.9
Total Projects	New Generation	2,090.7	10,016.5	0.0	2,105.1	2,216.1	1,604.1	9,043.2	416.9	566.5	525.0	16,387.6	1,259.0	196.3	2,406.9	740.9	0.0	5.3	1,365.8	1,938.0	719.8	1,749.5	0.0	55,353.2
	Upgrade	20.0	3,090.6	0.0	1,762.3	428.3	115.0	2,776.3	308.0	76.2	0.0	2,092.0	169.0	0.0	149.1	459.0	0.0	60.0	431.4	0.0	40.0	15.0	0.0	11,992.2

Renewable Hybrid Project Analysis

Table 12-45 shows the status of all renewable hybrid generation projects (solar + storage, solar + wind and wind + storage) by number of projects that entered PJM generation queues from January 1, 1997, through June 30, 2023, by zone.[63] Of the 455 renewable hybrid projects currently active, suspended or under construction in the PJM generation queue, 106 projects (23.3 percent) are located in the AEP Zone.

Table 12-45 Status of all renewable hybrid generation queue projects by zone (number of projects): January 1, 1997 through June 30, 2023

		Number of Projects																						
Project Status	Project Classification	ACEC	AEP	AMPT	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
In Service	New Generation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	1
	Upgrade	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Under Construction	New Generation	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	2	0	3
	Upgrade	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Suspended	New Generation	0	0	0	5	3	0	0	0	0	0	0	0	3	0	7	0	0	1	0	0	0	0	19
	Upgrade	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	2
Withdrawn	New Generation	4	12	0	8	6	0	6	0	0	0	31	2	8	2	1	0	0	5	1	7	10	0	103
	Upgrade	0	0	0	0	0	0	0	0	0	0	1	0	0	0	1	0	0	0	0	0	0	0	2
Active	New Generation	6	98	0	31	7	0	21	12	2	3	74	7	25	5	18	1	1	24	3	37	1	0	376
	Upgrade	1	6	0	8	3	0	5	3	0	0	9	0	3	0	1	0	0	7	0	8	0	0	54
Total Projects	New Generation	10	110	0	44	16	0	27	12	2	3	106	9	36	7	26	1	1	30	4	44	14	0	502
	Upgrade	1	8	0	9	3	0	5	3	0	0	10	0	3	0	2	0	0	7	0	9	0	0	60

Table 12-46 shows the status of all renewable hybrid projects by MW that entered PJM generation queues from January 1, 1997, through June 30, 2023, by zone. Of the 37,948.0 MW of renewable hybrid generation currently active, suspended or under construction in the PJM generation queue, 13,910.8 MW (36.7 percent) are located in the AEP Zone.

Table 12-46 Status of all renewable hybrid generation queue projects by zone (MW): January 1, 1997 through June 30, 2023

		Project MW																						
Project Status	Project Classification	ACEC	AEP	AMPT	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
In Service	New Generation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.1	0.0	1.1
	Upgrade	0.0	0.0	0.0	16.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	16.3
Under Construction	New Generation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	17.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.6	0.0	19.6
	Upgrade	0.0	3.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.2
Suspended	New Generation	0.0	0.0	0.0	9.5	57.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	175.0	0.0	18.9	0.0	0.0	3.0	0.0	0.0	0.0	0.0	264.1
	Upgrade	0.0	100.0	0.0	0.0	0.0	0.0	0.0	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	150.0
Withdrawn	New Generation	14.5	3,860.8	0.0	568.0	484.9	0.0	986.9	0.0	0.0	0.0	2,339.9	104.5	1,004.0	70.0	20.0	0.0	0.0	304.2	20.0	291.0	36.1	0.0	10,104.8
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.7
Active	New Generation	206.0	13,282.6	0.0	3,515.7	603.8	0.0	3,132.5	610.8	50.0	107.5	8,051.1	286.5	2,098.1	165.0	303.3	178.5	5.0	1,538.4	1,452.0	489.0	20.0	0.0	36,095.8
	Upgrade	60.0	525.0	0.0	0.0	60.1	0.0	40.0	40.0	0.0	0.0	199.0	0.0	85.0	0.0	0.0	0.0	0.0	155.2	0.0	251.0	0.0	0.0	1,415.3
Total Projects	New Generation	220.5	17,143.4	0.0	4,093.3	1,146.4	0.0	4,119.4	610.8	50.0	107.5	10,408.0	391.0	3,277.1	235.0	342.2	178.5	5.0	1,845.7	1,472.0	780.0	59.7	0.0	46,485.4
	Upgrade	60.0	628.2	0.0	16.3	60.1	0.0	40.0	40.0	0.0	0.0	199.0	0.0	85.0	0.0	3.7	0.0	0.0	155.2	0.0	301.0	0.0	0.0	1,588.5

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

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."[64] Where the transmission owner is a vertically integrated company that also owns generation, there is a potential conflict of interest when the transmission owner evaluates the interconnection requirements of new generation which is a competitor to the generation or transmission of the parent company and when the transmission owner evaluates the interconnection requirements of new generation which is part of the same company as the transmission owner. There is also a potential conflict of interest when the transmission owner evaluates the interconnection requirements of a nonincumbent transmission developer which is a competitor of the transmission owner. The MMU recommends outsourcing interconnection studies to an independent party to avoid potential conflicts of interest.

Table 12-47 shows the relationship between the project developer and transmission owner for all project MW that have entered the PJM generation queue from January 1, 1997, through June 30, 2023, by transmission owner and unit type. A project where the developer is affiliated with the transmission owner is classified as related. A project where the developer is not affiliated with the transmission owner is classified as unrelated. For example, 36.0 MW of combined cycle generation projects that have entered the PJM generation queue in the DUKE Zone were projects developed by Duke Energy or subsidiaries of Duke Energy, the transmission owner for the DUKE Zone. These project MW are classified as related. There have been 667.5 MW of combined cycle projects that have entered the PJM generation queue in the DUKE Zone by developers not affiliated with Duke Energy. These project MW are classified as unrelated.

Of the 827,797.5 MW that have entered the queue during the time period of January 1, 1997, through June 30, 2023, 71,170.5 MW (8.6 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 39,506.7 MW that entered the queue in the PSEG Zone during the time period of January 1, 1997, through June 30, 2023, 13,532.3 MW (34.3 percent) were submitted by PSEG or one of their affiliated companies.

64 See OATT § 1 (Transmission Owner).

Table 12-47 Relationship between project developer and transmission owner for all interconnection queue projects MW by unit type: June 30, 2023

				MW by Unit Type																						
Parent Company	Transmission Owner	Related to Developer	Number of Projects	Battery	CC	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total	Percent of Total
AEP	AEP	Related	52	116.0	678.0	0.0	0.0	0.0	0.0	34.0	2.4	214.0	0.0	0.0	0.0	299.7	180.0	0.0	3,918.0	90.0	0.0	0.0	0.0	0.0	5,532.1	3.5%
		Unrelated	1,253	12,991.1	21,973.5	2,594.1	7.5	506.5	0.0	0.0	453.6	0.0	12.0	0.0	75.4	55,779.3	17,591.6	0.0	10,399.0	0.0	0.0	452.0	31,196.9	0.0	154,032.4	96.5%
AES	DAY	Related	14	20.0	0.0	47.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	21.5	0.0	0.0	1,347.5	0.0	0.0	0.0	0.0	0.0	1,436.0	11.6%
		Unrelated	136	704.9	1,150.0	264.5	0.0	12.0	0.0	0.0	0.0	0.0	0.0	0.0	10.0	5,933.9	650.8	0.0	0.0	0.0	0.0	0.0	2,228.0	0.0	10,954.1	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	206.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	206.0	100.0%
DUQ	DUQ	Related	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	49	525.0	665.0	237.9	40.0	19.2	0.0	0.0	194.6	1,879.0	0.0	0.0	0.0	121.9	107.5	0.0	2,810.0	0.0	0.0	20.0	0.0	0.0	6,620.1	100.0%
DOM	DOM	Related	220	1,171.7	11,397.5	2,045.7	100.0	0.0	0.0	340.0	0.0	1,944.0	0.0	0.0	60.0	6,369.1	17.0	0.0	301.0	0.0	0.0	4.0	2,786.0	0.0	26,536.1	22.0%
		Unrelated	1,180	17,307.9	9,268.5	2,225.8	0.5	227.3	0.0	0.0	35.0	0.0	0.0	10.0	116.2	46,152.2	10,440.0	0.0	20.0	0.0	0.0	316.3	7,946.4	150.0	94,216.1	78.0%
DUKE	DUKE	Related	12	37.3	36.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	105.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	178.7	5.6%
		Unrelated	44	605.4	667.5	0.0	0.0	0.0	0.0	0.0	112.0	0.0	0.0	0.0	4.8	1,462.9	40.0	10.0	120.0	0.0	0.0	0.0	0.0	0.0	3,022.6	94.4%
EKPC	EKPC	Related	2	0.0	821.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	821.8	6.5%
		Unrelated	157	196.3	170.0	73.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7,955.9	3,362.1	0.0	0.0	0.0	0.0	0.0	150.3	0.0	11,907.5	93.5%
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	390	2,110.7	9,048.4	807.4	388.0	20.7	2.8	0.0	0.0	0.0	2.0	5.0	10.3	2,972.7	280.5	0.0	15.0	5.5	0.0	10.0	8,097.7	0.0	23,776.7	97.8%
	BGE	Related	15	22.5	250.0	10.0	0.0	0.0	0.0	0.0	0.0	117.2	0.0	0.0	8.5	20.0	0.0	0.0	10.0	101.0	0.0	0.0	0.0	0.0	539.2	5.9%
		Unrelated	77	1,696.6	3,012.1	166.6	18.0	133.0	0.0	0.0	0.4	3,280.0	1.3	0.0	0.0	257.6	0.0	0.0	0.0	2.5	0.0	25.0	0.0	0.0	8,593.1	94.1%
	COMED	Related	17	0.0	0.0	296.0	0.0	0.0	0.0	0.0	0.0	1,185.0	0.0	0.0	0.0	9.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,490.0	1.6%
		Unrelated	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	17,652.1	3,960.4	199.0	1,926.0	91.0	0.0	90.0	40,225.7	0.0	94,428.7	98.4%
	DPL	Related	5	1.0	60.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	68.4	0.3%
		Unrelated	424	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	5,193.6	391.0	0.0	653.0	15.0	0.0	65.0	10,640.3	0.0	27,253.5	99.7%
	PECO	Related	33	40.0	7,515.0	5.0	83.0	0.0	0.0	0.0	265.0	437.8	0.0	0.0	0.0	0.0	0.0	0.0	7.0	0.0	0.0	0.0	0.0	0.0	8,352.8	28.0%
		Unrelated	98	25.3	20,610.5	596.5	8.5	15.0	0.0	0.0	0.0	0.0	0.0	17.0	3.7	246.9	5.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	21,528.4	72.0%
	PEPCO	Related	5	1.0	503.0	0.0	0.0	4.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	508.0	1.7%
		Unrelated	120	1,937.0	23,827.9	92.3	34.0	5.0	0.0	0.0	0.0	1,640.0	32.0	0.0	3.5	684.3	1,472.0	0.0	0.0	6.0	0.0	0.0	0.0	0.0	29,734.0	98.3%
First Energy	APS	Related	10	0.0	1,453.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	71.2	0.0	0.0	1,710.0	0.0	0.0	0.0	0.0	0.0	3,234.2	5.1%
		Unrelated	673	3,867.4	29,272.8	1,479.7	0.0	84.4	0.0	0.0	638.3	0.0	154.4	53.8	25.4	9,758.8	4,093.3	0.0	4,092.0	0.0	0.0	184.4	6,069.7	16.3	59,790.6	94.9%
	ATSI	Related	6	0.0	1,678.0	0.0	0.0	0.0	0.0	0.0	0.0	16.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,694.0	5.4%
		Unrelated	284	2,644.4	13,647.0	588.7	10.5	166.4	0.0	0.0	0.0	0.0	59.7	6.6	6.9	9,004.7	1,206.5	0.0	0.0	16.5	0.0	0.0	2,111.7	0.0	29,469.5	94.6%
	JCPLC	Related	2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20.0	0.0	0.0	0.0	0.0	12.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	32.0	0.1%
		Unrelated	490	2,556.0	15,751.4	542.1	0.0	4.8	0.6	30.0	1.6	0.0	0.6	0.0	12.8	2,783.7	235.0	0.0	0.0	0.0	0.0	30.0	23,787.1	0.0	45,735.6	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	219	1,199.9	17,488.9	57.6	1,204.4	52.1	0.0	0.0	0.0	93.0	0.0	8.0	23.2	1,888.1	345.9	0.0	0.0	0.0	0.0	84.0	0.0	0.0	22,445.1	100.0%
	PE	Related	4	0.0	534.0	5.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,860.0	0.0	0.0	0.0	0.0	0.0	2,399.0	5.4%
		Unrelated	625	1,797.2	18,747.9	1,532.2	0.0	218.0	3.0	16.0	46.3	0.0	341.8	8.0	14.8	8,857.7	2,000.9	0.0	561.0	590.0	0.0	525.0	7,142.1	0.0	42,401.7	94.6%
OVEC	OVEC	Related	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	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	508.0	178.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	686.5	100.0%
PPL	PPL	Related	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	3,641.1	991.0	0.0	6,896.6	0.0	0.0	31.0	4,242.5	90.0	43,843.5	91.1%
PSEG	PSEG	Related	107	0.0	11,086.1	1,818.1	0.0	0.0	0.0	0.0	0.0	381.0	0.0	0.0	0.0	175.4	3.7	0.0	24.0	44.0	0.0	0.0	0.0	0.0	13,532.3	34.3%
		Unrelated	280	1,764.5	17,971.9	1,137.9	600.0	62.5	4.9	0.0	1,000.0	0.0	10.6	0.0	13.7	697.3	56.1	0.0	0.0	25.0	0.0	0.0	2,630.0	0.0	25,974.4	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	533	1,409.5	38,803.4	4,226.8	183.0	4.0	0.0	374.0	396.4	5,945.0	0.0	0.0	68.5	7,245.7	200.7	0.0	9,288.5	235.0	0.0	4.0	2,786.0	0.0	71,170.5	8.6%
		Unrelated	7,632	65,936.0	251,708.1	15,439.6	2,962.3	1,867.1	16.3	1,246.0	2,647.0	7,330.0	669.3	110.8	517.7	181,758.7	47,407.9	209.0	27,492.6	751.5	0.0	1,832.7	146,468.2	256.3	756,627.0	91.4%

Combined Cycle Project Developer and Transmission Owner Relationships

Table 12-48 shows the relationship between the project developer and transmission owner for all combined cycle project MW that have entered the PJM generation queue from January 1, 1997, through June 30, 2023, by transmission owner and project status. Of the 48,398.8 combined cycle project MW that are in service or currently under construction, 8,624.6 MW (17.8 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 June 30, 2023, 821.8 MW (82.9 percent) have been submitted by EKPC or one of their affiliated companies.

Table 12-48 Relationship between project developer and transmission owner for all combined cycle project MW in the queue: June 30, 2023

			MW by Project Status						
Parent Company	Transmission Owner	Related to Developer	Active	In Service	Under Construction	Suspended	Withdrawn	Total	Percent of Total
AEP	AEP	Related	0.0	678.0	0.0	0.0	0.0	678.0	3.0%
		Unrelated	285.0	6,183.0	50.0	1,150.0	14,305.5	21,973.5	97.0%
AES	DAY	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	0.0	0.0	0.0	0.0	1,150.0	1,150.0	100.0%
AMP	AMPT	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
DUQ	DUQ	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	0.0	0.0	0.0	0.0	665.0	665.0	100.0%
DOM	DOM	Related	94.0	4,762.5	0.0	0.0	6,541.0	11,397.5	55.2%
		Unrelated	24.0	2,044.1	0.0	0.0	7,200.4	9,268.5	44.8%
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	5.0	3,740.5	0.0	0.0	16,865.0	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	3,410.0	2,384.7	20.0	1,270.0	22,188.1	29,272.8	95.3%
	ATSI	Related	0.0	0.0	0.0	0.0	1,678.0	1,678.0	10.9%
		Unrelated	998.0	4,095.0	0.0	955.0	7,599.0	13,647.0	89.1%
	JCPLC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	0.0	1,775.8	0.0	0.0	13,975.6	15,751.4	100.0%
	MEC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	0.0	2,670.9	75.0	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	6,667.0	51.6	0.0	17,959.7	24,678.3	91.6%
PSEG	PSEG	Related	0.0	1,738.0	51.1	0.0	9,297.0	11,086.1	38.2%
		Unrelated	0.0	806.4	0.0	0.0	17,165.5	17,971.9	61.8%
Con Ed	REC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	0.0	0.0	0.0	0.0	6.9	6.9	100.0%
Total		Related	94.0	8,573.5	51.1	0.0	30,084.8	38,803.4	13.4%
		Unrelated	4,797.0	39,474.9	299.3	3,950.0	203,186.8	251,708.1	86.6%

Combustion Turbine – Natural Gas Project Developer and Transmission Owner Relationships

Table 12-49 shows the relationship between the project developer and transmission owner for all CT – natural gas project MW that have entered the PJM generation queue from January 1, 1997, through June 30, 2023, by transmission owner and project status. Of the 9,886.9 CT – natural gas project MW that are in service or currently under construction, 1,803.0 (18.2 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 June 30, 2023, 1,818.1 MW (61.5 percent) have been submitted by PSEG or one of their affiliated companies.

Table 12-49 Relationship between project developer and transmission owner for all CT – natural gas project MW in the queue: June 30, 2023

			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	791.0	278.1	0.0	0.0	1,525.0	2,594.1	100.0%
AES	DAY	Related	0.0	47.0	0.0	0.0	0.0	47.0	15.1%
		Unrelated	20.0	36.5	0.0	0.0	208.0	264.5	84.9%
AMP	AMPT	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
DUQ	DUQ	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	0.0	219.4	0.0	0.0	18.5	237.9	100.0%
DOM	DOM	Related	1,138.0	824.0	0.0	0.0	83.7	2,045.7	47.9%
		Unrelated	0.0	1,182.7	0.0	0.0	1,043.1	2,225.8	52.1%
DUKE	DUKE	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
EKPC	EKPC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	0.0	0.0	0.0	0.0	73.0	73.0	100.0%
Exelon	ACEC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	230.0	404.4	0.0	0.0	173.0	807.4	100.0%
	BGE	Related	0.0	10.0	0.0	0.0	0.0	10.0	5.7%
		Unrelated	0.0	13.0	0.0	0.0	153.6	166.6	94.3%
	COMED	Related	296.0	0.0	0.0	0.0	0.0	296.0	17.5%
		Unrelated	123.2	888.0	0.0	0.0	383.0	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	35.3	44.0	0.0	0.0	13.0	92.3	100.0%
First Energy	APS	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	30.0	1,445.7	0.0	0.0	4.0	1,479.7	100.0%
	ATSI	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	458.7	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	46.1	11.5	0.0	0.0	57.6	100.0%
	PE	Related	0.0	5.0	0.0	0.0	0.0	5.0	0.3%
		Unrelated	0.0	394.9	20.5	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	675.0	234.0	1,137.9	38.5%
Con Ed	REC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
Total		Related	1,434.0	1,803.0	0.0	0.0	989.8	4,226.8	21.5%
		Unrelated	1,688.2	8,051.9	32.0	675.0	4,992.5	15,439.6	78.5%

Wind Project Developer and Transmission Owner Relationships

Table 12-50 shows the relationship between the project developer and transmission owner for all wind project MW that have entered the PJM generation queue from January 1, 1997, through June 30, 2023, by transmission owner and project status. Of the 11,228.1 wind project MW that are in service or currently under construction, 12.0 MW (0.1 percent) have been developed by transmission owners building in their own service territory. DOM is the transmission owner with the highest percentage of affiliates building wind projects in their own service territory. Of the 10,732.4 MW that entered the queue in the DOM Zone during the time period of January 1, 1997, through June 30, 2023, 2,786.0 MW (26.0 percent) have been submitted by DOM or one of their affiliated companies.

Table 12-50 Relationship between project developer and transmission owner for all wind project MW in the queue: June 30, 2023

			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	2,550.9	3,544.6	0.0	0.0	25,101.4	31,196.9	100.0%
AES	DAY	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	100.0	0.0	0.0	0.0	2,128.0	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	2,640.0	12.0	0.0	0.0	134.0	2,786.0	26.0%
		Unrelated	2,667.5	310.5	0.0	0.0	4,968.4	7,946.4	74.0%
DUKE	DUKE	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
EKPC	EKPC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	0.0	0.0	0.0	0.0	150.3	150.3	100.0%
Exelon	ACEC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	3,141.6	7.5	0.0	0.0	4,948.6	8,097.7	100.0%
	BGE	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
	COMED	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	9,273.3	4,502.1	100.8	0.0	26,349.5	40,225.7	100.0%
	DPL	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	7,369.5	0.0	0.0	0.0	3,270.8	10,640.3	100.0%
	PECO	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
	PEPCO	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
First Energy	APS	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	949.1	1,369.0	0.0	80.0	3,671.6	6,069.7	100.0%
	ATSI	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	297.7	0.0	0.0	0.0	1,814.0	2,111.7	100.0%
	JCPLC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	16,390.1	0.0	0.0	0.0	7,397.0	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	486.7	1,067.5	87.6	0.0	5,500.3	7,142.1	100.0%
OVEC	OVEC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
PPL	PPL	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	174.8	226.5	0.0	0.0	3,841.2	4,242.5	100.0%
PSEG	PSEG	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	2,610.0	0.0	0.0	0.0	20.0	2,630.0	100.0%
Con Ed	REC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
Total		Related	2,640.0	12.0	0.0	0.0	134.0	2,786.0	1.9%
		Unrelated	46,011.1	11,027.7	188.4	80.0	89,161.0	146,468.2	98.1%

Solar Project Developer and Transmission Owner Relationships

Table 12-51 shows the relationship between the project developer and transmission owner for all solar project MW that have entered the PJM generation queue from January 1, 1997, through June 30, 2023, by transmission owner and project status. Of the 9,236.0 solar project MW that are in service or currently under construction, 1,822.7 MW (19.7 percent) have been developed by transmission owners building in their own service territory. PSEG is the transmission owner with the highest percentage of affiliates building solar projects in their own service territory. Of the 872.7 MW that entered the queue in the PSEG Zone during the time period of January 1, 1997, through June 30, 2023, 175.4 MW (20.1 percent) have been submitted by PSEG or one of their affiliated companies.

Table 12-51 Relationship between project developer and transmission owner for all solar project MW in the queue: June 30, 2023

			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	44,365.7	976.5	365.7	475.0	9,596.4	55,779.3	99.5%
AES	DAY	Related	0.0	0.0	0.0	0.0	21.5	21.5	0.4%
		Unrelated	2,680.9	2.5	599.6	327.9	2,323.1	5,933.9	99.6%
AMP	AMPT	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	206.0	0.0	0.0	0.0	0.0	206.0	100.0%
DUQ	DUQ	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	34.7	0.0	54.2	0.0	33.0	121.9	100.0%
DOM	DOM	Related	4,380.3	1,330.1	307.0	99.9	251.9	6,369.2	12.1%
		Unrelated	24,761.8	1,831.2	1,131.7	1,037.0	17,390.6	46,152.2	87.9%
DUKE	DUKE	Related	49.0	0.0	0.0	0.0	56.4	105.4	6.7%
		Unrelated	549.9	200.0	80.0	0.0	633.0	1,462.9	93.3%
EKPC	EKPC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	6,800.0	50.0	0.0	95.0	1,010.9	7,955.9	100.0%
Exelon	ACEC	Related	0.0	0.0	0.0	0.0	8.3	8.3	0.3%
		Unrelated	571.0	65.0	2.6	49.7	2,284.4	2,972.7	99.7%
	BGE	Related	0.0	0.0	0.0	0.0	20.0	20.0	7.2%
		Unrelated	154.9	1.1	0.0	0.0	101.6	257.6	92.8%
	COMED	Related	0.0	9.0	0.0	0.0	0.0	9.0	0.1%
		Unrelated	13,265.4	0.0	100.0	102.5	4,184.2	17,652.1	99.9%
	DPL	Related	0.0	7.4	0.0	0.0	0.0	7.4	0.1%
		Unrelated	2,023.8	273.6	150.0	0.0	2,746.3	5,193.6	99.9%
	PECO	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	129.4	3.3	0.0	0.0	114.2	246.9	100.0%
	PEPCO	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	210.7	30.0	0.0	0.0	443.6	684.3	100.0%
First Energy	APS	Related	71.2	0.0	0.0	0.0	0.0	71.2	0.7%
		Unrelated	6,071.6	140.5	93.8	365.0	3,088.0	9,758.8	99.3%
	ATSI	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	5,960.0	0.0	443.0	445.0	2,156.7	9,004.7	100.0%
	JCPLC	Related	0.0	0.0	0.0	0.0	12.0	12.0	0.4%
		Unrelated	704.6	432.0	0.0	11.0	1,636.1	2,783.7	99.6%
	MEC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	696.1	0.0	60.0	67.0	1,065.0	1,888.1	100.0%
	PE	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	5,735.8	53.5	100.0	184.2	2,784.2	8,857.7	100.0%
OVEC	OVEC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	430.0	0.0	0.0	0.0	78.0	508.0	100.0%
PPL	PPL	Related	146.8	0.0	0.0	0.0	0.0	146.8	3.9%
		Unrelated	2,359.8	25.0	20.0	146.2	1,090.1	3,641.1	96.1%
PSEG	PSEG	Related	0.0	129.3	5.2	0.0	40.9	175.4	20.1%
		Unrelated	18.0	112.6	16.1	19.9	530.7	697.3	79.9%
Con Ed	REC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
Total		Related	4,747.2	1,510.5	312.2	99.9	576.0	7,245.7	3.8%
		Unrelated	117,730.0	4,196.7	3,216.7	3,325.3	53,290.0	181,758.7	96.2%

Battery Project Developer and Transmission Owner Relationships

Table 12-52 shows the relationship between the project developer and transmission owner for all battery project MW that have entered the PJM generation queue from January 1, 1997, through June 30, 2023, by transmission owner and project status. Of the 303.3 battery project MW that are in service or currently under construction, 60.0 MW (19.8 percent) have been developed by transmission owners building in their own service territory. PECO is the transmission owner with the highest percentage of affiliates building battery projects in their own service territory. Of the 65.3 MW that entered the queue in the PECO Zone during the time period of January 1, 1997, through June 30, 2023, 40.0 MW (61.3 percent) have been submitted by PECO or one of their affiliated companies.

Table 12-52 Relationship between project developer and transmission owner for all battery project MW in the queue: June 30, 2023

			MW by Project Status						
Parent Company	Transmission Owner	Related to Developer	Active	In Service	Under Construction	Suspended	Withdrawn	Total	Percent of Total
AEP	AEP	Related	100.0	6.0	0.0	0.0	10.0	116.0	0.9%
		Unrelated	11,275.9	4.0	0.0	0.0	1,711.2	12,991.1	99.1%
AES	DAY	Related	0.0	20.0	0.0	0.0	0.0	20.0	2.8%
		Unrelated	290.0	0.0	0.0	0.0	414.9	704.9	97.2%
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	505.0	0.0	0.0	0.0	20.0	525.0	100.0%
DOM	DOM	Related	1,151.7	0.0	20.0	0.0	0.0	1,171.7	6.3%
		Unrelated	14,936.5	0.0	0.0	0.0	2,371.4	17,307.9	93.7%
DUKE	DUKE	Related	0.0	14.0	0.0	0.0	23.3	37.3	5.8%
		Unrelated	527.2	6.0	0.0	0.0	72.2	605.4	94.2%
EKPC	EKPC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	176.0	0.0	0.0	0.0	20.3	196.3	100.0%
Exelon	ACEC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	1,924.2	0.0	0.0	0.0	186.5	2,110.7	100.0%
	BGE	Related	2.5	0.0	0.0	0.0	20.0	22.5	1.3%
		Unrelated	1,455.0	0.0	1.0	0.0	240.6	1,696.6	98.7%
	COMED	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	9,718.2	86.0	0.0	0.0	2,015.4	11,819.5	100.0%
	DPL	Related	1.0	0.0	0.0	0.0	0.0	1.0	0.1%
		Unrelated	1,063.0	0.0	0.0	0.0	364.0	1,427.0	99.9%
	PECO	Related	0.0	0.0	0.0	0.0	40.0	40.0	61.3%
		Unrelated	0.0	1.0	0.0	0.0	24.3	25.3	38.7%
	PEPCO	Related	1.0	0.0	0.0	0.0	0.0	1.0	0.1%
		Unrelated	1,917.0	0.0	0.0	0.0	20.0	1,937.0	99.9%
First Energy	APS	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	3,431.5	39.9	0.0	0.0	396.0	3,867.4	100.0%
	ATSI	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	2,418.0	0.0	0.0	0.0	226.4	2,644.4	100.0%
	JCPLC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	1,572.8	40.0	14.0	0.0	929.2	2,556.0	100.0%
	MEC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	836.2	0.0	0.0	0.0	363.7	1,199.9	100.0%
	PE	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	1,367.8	28.4	0.0	0.0	401.0	1,797.2	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	400.0	20.0	0.0	20.0	319.8	759.8	100.0%
PSEG	PSEG	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	1,575.0	3.0	0.0	7.0	179.5	1,764.5	100.0%
Con Ed	REC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
Total		Related	1,256.2	40.0	20.0	0.0	93.3	1,409.5	2.1%
		Unrelated	55,389.3	228.3	15.0	27.0	10,276.4	65,936.0	97.9%

Renewable Hybrid Project Developer and Transmission Owner Relationships

Table 12-53 shows the relationship between the project developer and transmission owner for all renewable hybrid project MW that have entered the PJM generation queue from January 1, 1997, through June 30, 2023, by transmission owner and project status. Of the 40.1 renewable hybrid project MW that are in service or currently under construction, 20.7 MW (51.5 percent) have been developed by transmission owners building in their own service territory. PSEG is the transmission owner with the highest percentage of affiliates building hybrid projects in their own service territory. Of the 59.7 MW that entered the queue in the PSEG Zone during the time period of January 1, 1997, through June 30, 2023, 3.7 MW (6.2 percent) have been submitted by PSEG or one of their affiliated companies.

Table 12-53 Relationship between project developer and transmission owner for all hybrid project MW in the queue: June 30, 2023

			MW by Project Status						
Parent Company	Transmission Owner	Related to Developer	Active	In Service	Under Construction	Suspended	Withdrawn	Total	Percent of Total
AEP	AEP	Related	180.0	0.0	0.0	0.0	0.0	180.0	1.0%
		Unrelated	13,627.6	0.0	3.2	100.0	3,860.8	17,591.6	99.0%
AES	DAY	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	650.8	0.0	0.0	0.0	0.0	650.8	100.0%
AMP	AMPT	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
DUQ	DUQ	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	107.5	0.0	0.0	0.0	0.0	107.5	100.0%
DOM	DOM	Related	0.0	0.0	17.0	0.0	0.0	17.0	0.2%
		Unrelated	8,250.1	0.0	0.0	0.0	2,339.9	10,590.0	99.8%
DUKE	DUKE	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	50.0	0.0	0.0	0.0	0.0	50.0	100.0%
EKPC	EKPC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	2,183.1	0.0	0.0	175.0	1,004.0	3,362.1	100.0%
Exelon	ACEC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	266.0	0.0	0.0	0.0	14.5	280.5	100.0%
	BGE	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
	COMED	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	3,172.5	0.0	0.0	0.0	986.9	4,159.4	100.0%
	DPL	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	286.5	0.0	0.0	0.0	104.5	391.0	100.0%
	PECO	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	5.0	0.0	0.0	0.0	0.0	5.0	100.0%
	PEPCO	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	1,452.0	0.0	0.0	0.0	20.0	1,472.0	100.0%
First Energy	APS	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	3,515.7	16.3	0.0	9.5	568.0	4,109.6	100.0%
	ATSI	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	663.9	0.0	0.0	57.7	484.9	1,206.5	100.0%
	JCPLC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	165.0	0.0	0.0	0.0	70.0	235.0	100.0%
	MEC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	303.3	0.0	0.0	18.9	23.7	345.9	100.0%
	PE	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	1,693.6	0.0	0.0	3.0	304.2	2,000.9	100.0%
OVEC	OVEC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	178.5	0.0	0.0	0.0	0.0	178.5	100.0%
PPL	PPL	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	740.0	0.0	0.0	50.0	291.0	1,081.0	100.0%
PSEG	PSEG	Related	0.0	1.1	2.6	0.0	0.0	3.7	6.2%
		Unrelated	20.0	0.0	0.0	0.0	36.1	56.1	93.8%
Con Ed	REC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
Total		Related	180.0	1.1	19.6	0.0	0.0	200.7	0.4%
		Unrelated	37,331.1	16.3	3.2	414.1	10,108.5	47,873.2	99.6%

Network Transmission Project Costs

Any entity that requests interconnection of a new generating facility, including increases to the capacity of an existing generating unit, or that requests interconnection of a merchant transmission facility, must follow the process defined in the PJM tariff to obtain interconnection service.[65] 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.[66] 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.[67] On June 30, 2023, there were 3,521 projects in generation request queues in the status of active, under construction or suspended, and 1,320 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.[68] 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.[69] For example, the 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.[70]

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

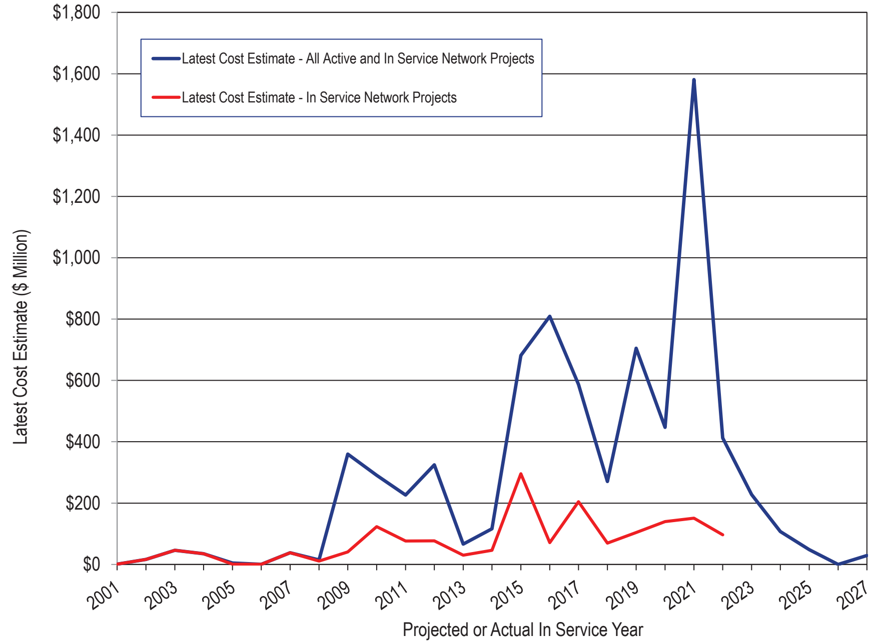
65 See OATT Parts IV & VI.
66 See "PJM Manual 14B: PJM Regional Transmission Planning Process," Rev. 52 (April 10, 2023).
67 See "PJM Manual 14G: Generation Interconnection Requests," Rev. 8 (July 26, 2023).
68 Winter peak load is included in the generation deliverability powerflow analysis during the 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.
69 See "PJM Manual 14B: PJM Region Transmission Planning Process," Rev. 53 (July 26, 2023).
70 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>.

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.[71] 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.[72] [73] In order to retain the prior 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 underutilized transmission system capability.[74] 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 network transmission project cost estimates by projected and actual in service year for network projects in the status of active or in service. The increase in estimated network upgrade costs for projects in the planning process in recent years is a result of the large number of requests in the new services queue and the existing backlog (Figure 12-5). However, as generation requests withdraw from the queue, the overall network costs decrease and 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. PJM does not track final project costs, so the in service costs only reflect the last estimate provided by PJM before the project went in service. Given the significance of this information to market participants and regulators, the MMU recommends that estimated network costs for queue resources, in service dates for queue resources and final project interconnection costs be updated regularly and with accurate and verifiable data.

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



71 183 FERC ¶61,009.

72 *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).

73 *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).

74 183 FERC ¶61,009 at 31.

Regional Transmission Expansion Plan (RTEP)[75]

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; to identify new transmission enhancements that result in economic benefits; and to identify economic benefits associated with modification to existing RTEP reliability based enhancements that when modified would relieve one or more economic constraints. PJM identifies the economic benefit of proposed transmission projects based on production cost analyses.[76] PJM presents the RTEP market efficiency enhancements to the PJM Board, along with stakeholder input, for Board approval.

To be recommended to the PJM Board of Managers for approval, the relative benefits and costs of the economic based enhancement or expansion of the proposed project must reduce congestion on one or more constraints by at least one dollar, meet a ratio threshold of at least 1.25:1 and have an independent cost review, performed by PJM, if expected costs are over $50 million. PJM provides the review of a project with a projected cost of over $50 million using its own staff or outside consultants that are hired to assist in the review. PJM presents its findings to the TEAC where PJM's findings are reviewed by the stakeholders. While stakeholders can comment on the findings, PJM makes the final decision about what costs will be used for the purpose of calculating the cost/benefit ratio for the project. The cost/benefit ratio is the ratio of the present value of the total annual benefit for 15 years to the present value of the total annual cost for the first 15 years of the life of the enhancement or expansion.

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

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

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

75 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. 53 (July 26 2023).

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

window was open from November 1, 2014, through February 28, 2015. This window accepted proposals to address historical congestion on 12 identified flowgates. PJM received 93 proposals from 19 entities. Thirteen projects, 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.[77]

The fifth market efficiency cycle was performed for the 2020/2021 RTEP long term window. The 2020/2021 RTEP long term window was open from November 11, 2020, through May 11, 2021. This window accepted proposals to address historical congestion on four internal flowgates. PJM received 24 proposals from seven entities. Four projects, all submitted by an incumbent transmission owner, were approved by the PJM Board.

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

The Cost/Benefit Evaluation

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

The total benefit of a project is calculated as the sum of the net present value of calculated energy market benefits and calculated reliability pricing model (RPM) benefits for a 15 year period, starting with the projected in service date of the project. PJM measures benefits as reductions in estimated load charges and production costs in the energy market and reductions in estimated load capacity payments and in system capacity costs in the capacity market, but does not weight increases and decreases in benefits equally. The method for calculating energy market benefits and reliability pricing model benefits depends on whether the project is regional or subregional. A regional project is any project rated at or above 230 kV. A subregional project is any project rated at less than 230 kv.

The energy market benefit analysis uses an energy market simulation tool that produces an hourly least-cost, security constrained market solution, including total operational costs, hourly LMPs, bus specific injections and bus specific withdrawals for each modeled year with and without the proposed RTEP project. Using the output from the model, PJM calculates changes in energy production costs and load energy payments.

The definition of the energy benefit analysis depends on whether the project is regional or subregional. For a regional project, the energy benefit for each modeled year is equal to 50 percent of the change in system wide total system

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

energy production costs with and without the project plus 50 percent of the change in zonal load payments with and without the project, including only those zones where the project reduced the load payments. For subregional projects, the calculation of benefits for each modeled year ignores any impact on system wide energy production costs and is instead based only the change in zonal load energy payments with and without the project, but including only those zones where the project reduced the load energy payments.

In both the regional and subregional analysis, changes in zonal load energy payments are netted against changes in the estimated value of any Auction Revenue Rights (ARR) that sink in that zone for purposes of determining whether a zone benefits from a proposed RTEP project. Estimated ARR credits are calculated for each simulated year using the most recent planning year's actual ARR MW combined with FTR prices assumed to be equal to the market simulation's CLMP differences between ARR source and sink points. The value of the ARR rights with and without the RTEP project is evaluated based on changes in modeled CLMPs on the latest allocation of ARR rights. ARR MW allocations are not adjusted to reflect any potential changes in ARR allocations which may be allowed by the RTEP upgrade and the value of the ARRs are assumed to match the forecasted CLMP differences on the ARR paths.

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

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

The difference in the benefits calculation used in the regional and subregional cost/benefit threshold tests is related to how the direct costs of the transmission projects are allocated for approved regional and subregional projects. The costs of an approved regional project are allocated so that 50 percent of the total costs are allocated on a system wide load ratio share basis and the remaining 50 percent of the total costs are allocated to zones with projected energy market benefits and reliability pricing model benefits in proportion to those projected positive benefits. The costs of an approved subregional project are allocated so that the total costs of the project is allocated to zones with projected energy market benefits and reliability pricing model benefits in proportion to those projected positive benefits.

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

The recent introduction of storage as transmission assets (SATA) raises a number of additional concerns about PJM's cost/benefit analysis. PJM's cost/cost analysis uses a 15 year forecast for purposes of evaluating benefits and costs of traditional transmission assets with an expected useful life of 50 years or more. Using the same 15 year horizon does not make sense for SATA resources with an expected useful life of 10 years or less, depending on use. Using a 15 year benefit horizon will exaggerate the forecasted benefit stream relative to the stream of benefits that could be produced over the expected useful life relative to traditional transmission assets. Further, the rules for how to account for the actual, and forecasted, revenues and charges for operating the SATA to provide transmission load relief have not been established.

Without clear rules on how to allocate operational revenues and costs it is impossible to develop forecasted benefits and/or costs of a SATA project.

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

The Transource Project

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

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

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

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

Subsequent studies of the 9A project have reduced its benefit/cost ratio as a result of increased costs, decreased congestion on the AP South Interface since 2014 and a reduction in peak load forecasts since 2015.

PJM's 2019 study using simulations for years 2017, 2021, 2024 and 2027 had a cost benefit ratio of 2.10 with a capital cost of $383.63 million. The sum of the positive (energy cost reductions) effects was $855.19 million, a reduction of $322 million (28.0 percent) from the initial study. The sum of negative effects (energy cost increases) was $827.34 million, a reduction of $27.86 million (3.3 percent) from the results of the initial study. The net actual benefit of the project in the 2019 study was $27.85 million, not the $1,188.07 from the initial study. Using the total benefits (positive and negative) to compare to the net present value of costs in the 2019 analysis, the benefit to cost ratio was 0.07, not 2.10. The project should have been rejected on those grounds.

A portion of Project 9A in Pennsylvania was challenged in a proceeding at the Pennsylvania PUC. On May 20, 2021, the Pennsylvania PUC denied the Transource application to build in Pennsylvania based on failure to demonstrate need combined with negative economic and environmental effects.[78] Transource is appealing the decision at the state and federal level.[79]

78 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).

79 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.).

On May 5, 2022, the state court denied the appeal. The matter remains pending in the U.S. District Court for the Middle District of Pennsylvania.

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.[80] 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.[81]

While suspended, PJM is required by Schedule 6 of the Operating Agreement (OA) to "annually review the cost and benefits" of Board approved market efficiency projects that have not commenced construction or have not received state siting approval. Under Schedule 6, PJM's 2021 study showed a cost/benefit ratio of 1.00 with a capital cost of $453.71 million. The sum of the positive (energy cost reductions) effects was $452.4 million, a reduction of $735.7 million (-61.9 percent) from the initial study. The sum of negative effects (energy cost increases) was $452.4 million, a reduction of $399.3 million (46.9 percent) in the negative effects from the -$851.7 results of the initial study. The net benefit of the project in the 2021 study was -$159.8 million, not the $1,188.07 from the initial study. Using the total benefits (positive and negative) to compare to the net present value of costs in the 2019 analysis, the benefit to cost ratio was -0.35, not 2.10. The project should be rejected on these grounds rather than simply suspended.

PJM MISO Interregional Market Efficiency Process (IMEP)

PJM and MISO developed a process to facilitate the construction of interregional projects in response to the Commission's concerns about interregional coordination along the PJM-MISO seam. This process, called the Interregional Market Efficiency Process (IMEP), operates on a two year study schedule and is designed to address forward looking congestion. To qualify as an IMEP project, the project must be evaluated in a joint study process, qualify as an economic transmission enhancement in both PJM and MISO transmission expansion models and meet specific IMEP cost benefit criteria.[82] The allocation of costs to each RTO for IMEPs will be in proportion to the benefits received.

While the IMEP process is a joint effort, PJM and MISO perform their own analysis of benefits to their own system and each uses a different modeling approach and a different metric for determining the benefits of a proposed project. PJM makes use of the cost/benefit analysis used for its own internal market efficiency projects which will, by definition, overstate project benefits by ignoring areas where energy costs are increased. MISO, on the other hand, measures benefits as changes in projected system wide production cost caused by the project. The use of different approaches to measuring benefits is an issue when studying potential benefits of projects in a joint effort, and when using the defined benefits to allocate the costs of IMEP projects to each RTO. PJM's approach will over allocate the costs of IMEP projects to PJM members.

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

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

PJM MISO Targeted Market Efficiency Process (TMEP)

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

80 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>.

81 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>.

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

relief over a four year period, that exceed the expected installed capacity cost of the proposed project.[83] [84]

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

The allocation of costs to each RTO for an approved TMEP project will be in proportion to the benefits received by that RTO.[85] The proportion of benefits is calculated using the average shadow price of the constraint times the dfax to affected downstream buses times MW of load at the buses, which is effectively the proportion of congestion paid by the RTO. Within an RTO, the RTO's share of the cost of the approved project is allocated to each transmission control area in proportion to the benefits received by each transmission control area.

PJM and MISO did not conduct a TMEP study in 2019. As a result of decreases in M2M congestion and the addition of transmission upgrades already in process that affect the top congested historical M2M flowgates, PJM and MISO did not conduct a TMEP study in 2020. PJM and MISO agreed to assess the impact of planned upgrades and congestion using an additional year of market data. As a result, PJM and MISO did not conduct a TMEP study in 2021. The 2022 TMEP study focused on 23 flowgates as potential TMEP projects. Of the 23 initial flowgates, 19 were eliminated due to their relationship with other existing reliability projects already included in PJM's RTEP or MISO's MTEP plans, or the identified congestion was caused by outages.[86] Two projects were eliminated after studies showed that congestion was not persistent in October 2022, and an additional project was eliminated in December 2022 after further studies showed congestion was not persistent, leaving one TMEP project that was approved for implementation by the PJM Board on February 15, 2023, and by the MISO Board on March 23, 2023.[87] [88] PJM and MISO are currently performing an analysis to determine the need for a 2023 TMEP study.

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

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.[89] When a transmission project addresses a combination of reliability, market efficiency and/or public policy objectives, PJM can develop a multi driver approach project by identifying a more efficient or cost effective solution. PJM may choose a solution using either the proportional multi driver method or the incremental multi driver method. The proportional method combines separate solutions that address reliability, economics and/or public policy into a single transmission enhancement or expansion that incorporates separate drivers into one Multi-Driver Project. The incremental method expands or enhances a proposed single-driver solution to include one or more additional component(s) to address a combination of reliability,

83 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.," (December 11, 2008) <http://www.pjm.com/directory/merged-tariffs/miso-joa.pdf>.
84 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).
85 See *PJM Interconnection, L.L.C*, Docket No. ER17-729-000 (December 30, 2016).
86 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>.
87 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>.
88 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>.
89 See PJM. Docket No. ER14-2864 (September 12, 2014).

economic and/or public policy drivers.[90] On February 20, 2015, the Commission approved the tariff revisions with an effective date of November 12, 2014.[91]

On June 7, 2022, PJM opened its first multi driver proposal window. The window seeks to address reliability and market efficiency needs on three identified facilities. PJM accepted proposed solutions until August 8, 2022. PJM received 14 proposals from three entities. After conducting an independent cost review, a reliability analysis and a market efficiency analysis on the 14 proposals and a combination of the proposals, PJM proposed a combination of two proposals (Project 644 + 908) as its preferred solution. Two separate companies made the two proposals that were picked (644 and 908). The preferred solution (Project 644 + 908) has an estimated capital cost of $82.30 million ($85.50 million in present value of payments), with a PJM determined expected cost/benefit ratio of 1.99.[92] 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.

The cost/benefit analysis used in the multi driver review is the same flawed cost/benefit analysis that PJM uses for evaluating Market Efficiency projects. PJM's assumed benefit of the combined project was calculated as the sum of the present value of positive (energy cost reductions) effects of $169.8 million. The sum of the present value of negative effects (energy cost increases), which was ignored in the PJM calculation of benefits, was $149.1 million. The total benefit of the proposed multi driver project is therefore only $20.7 million, not the $169.8 asserted by PJM. Using the total benefits (positive and negative) to compare to the net present value of costs in the PJM's analysis, the benefit to cost ratio is 0.24, not 1.99. All $149.1 million of the increases in energy costs (negative benefits) would be paid by load in the ComEd Zone.

Supplemental Transmission Projects

Supplemental projects are asserted to be "transmission expansions or enhancements that are not required for compliance with PJM criteria and are not state 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."[93] 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.[94] Transmission owners have a clear incentive to increase investments in rate base given that transmission owners are paid for these projects on a cost of service basis.

Figure 12-6 shows the latest cost estimate of all baseline and supplemental projects by expected in service year. FERC Order No. 890 was issued on February 16, 2007, and implemented in PJM starting in 2008. Order No. 890 required Transmission Providers to participate in a coordinated, open and transparent planning process. Prior to the implementation of Order No.

90 See "PJM Manual 14B: PJM Region Transmission Planning Process," Rev. 53 (July 26, 2023).
91 150 FERC ¶ 61,117 (February 20, 2015).
92 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>.
93 See PJM. Planning. "Transmission Construction Status," (Accessed on June 30, 2023) <https://www.pjm.com/planning/project-construction>.
94 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).

890, there were transmission projects planned by transmission owners and included in the PJM planning models, that were not included in the totals shown in Figure 12-6, Table 12-54 and Table 12-55 because PJM did not track or report such projects. There has been a significant increase in supplemental projects coincident with the implementation of Order No. 890 starting in 2008 and the competitive planning process introduced by FERC Order No. 1000 starting in 2011.

Figure 12-6 Cost estimate of baseline and supplemental projects by expected in service year: January 1, 1998 through December 31, 2023

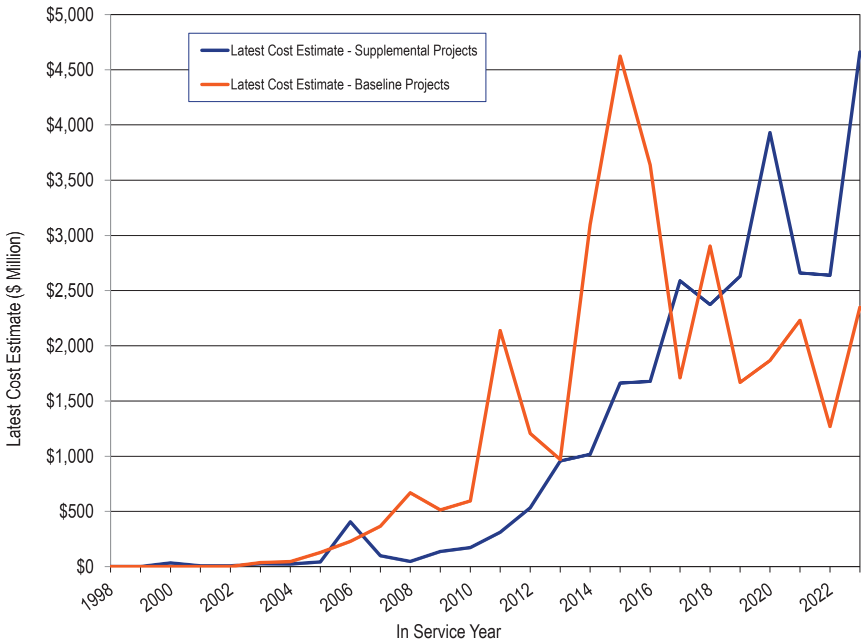


Table 12-54 shows the number of supplemental projects by expected in service year for each transmission zone. The average number of supplemental projects in each expected in service year increased by 955.0 percent, from 20 for years 1998 through 2007 (pre Order No. 890) to 211 for years 2008 through 2023 (post Order No. 890). As of June 30, 2023, there are 1,745 supplemental projects with expected in service dates between 2023 and 2027.

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

Year	ACEC	AEP	AMPT	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	NEET	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
1998	0	0	0	0	0	0	0	0	0	0	0	3	0	0	0	0	0	0	0	0	0	0	0	3
1999	0	0	0	0	0	0	0	0	0	0	0	2	0	0	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	6	4	0	40
2012	0	5	0	6	4	1	2	0	7	3	16	1	0	2	0	0	0	1	0	0	5	11	0	64
2013	5	21	0	4	5	0	11	0	6	4	13	1	0	1	1	0	0	1	0	1	14	19	0	107
2014	2	31	0	2	8	2	14	0	5	6	18	3	3	2	0	0	0	1	2	0	9	16	0	124
2015	4	15	0	2	9	1	37	0	8	4	17	5	3	2	0	0	0	1	0	4	7	24	0	143
2016	6	17	0	4	17	0	26	0	6	2	13	4	2	0	1	0	0	3	2	3	11	30	0	147
2017	8	107	0	3	26	1	23	0	3	8	31	11	5	0	3	0	0	0	3	1	22	43	0	298
2018	10	143	0	3	13	1	20	0	14	3	22	6	4	0	0	0	0	2	0	1	20	26	0	288
2019	3	160	0	4	30	5	14	2	16	1	33	8	5	3	14	0	0	1	15	0	15	27	0	356
2020	5	132	0	4	33	6	12	5	13	1	30	2	6	10	17	0	0	3	35	1	17	22	0	354
2021	4	151	0	6	31	7	3	7	13	2	22	0	8	16	23	0	0	23	24	0	19	22	0	381
2022	1	132	0	9	40	5	10	7	8	1	27	2	6	14	49	0	0	6	25	4	17	18	0	381
2023	9	322	2	3	30	0	5	19	9	1	38	4	6	3	33	2	5	5	35	2	15	25	0	573
2024	7	305	0	4	14	2	5	12	3	1	31	5	3	11	29	0	0	0	29	4	15	10	0	490
2025	8	257	5	1	21	3	3	12	4	1	25	3	1	1	27	0	0	2	50	1	13	14	0	452
2026	5	48	0	0	9	7	2	5	3	0	14	2	2	4	5	0	0	0	2	0	5	17	0	130
2027	1	63	0	0	6	1	0	2	2	2	5	1	2	0	1	0	0	0	0	0	6	8	0	100
2028	0	18	0	0	0	0	0	0	2	1	3	1	2	0	0	0	0	1	5	0	5	0	0	38
2029	0	0	0	0	1	3	0	0	0	0	0	0	0	0	0	0	0	0	1	0	12	0	0	17
2030	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	9	0	0	10
2031	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	9	0	0	10
2032	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	7	0	0	7
2033	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	7	0	0	7
2034	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	6	0	0	0	0	6
2035	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2036	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2037	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2038	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2039	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2040	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	101	1,947	7	119	298	54	231	71	122	60	374	158	58	75	207	2	5	62	243	22	275	355	0	4,846

Table 12-55 shows the latest cost estimate of supplemental projects by expected in service year for each transmission zone. The average cost of supplemental projects in each expected in service year increased by 2,450.1 percent, from $64.6 million for years 1998 through 2007 (pre Order No. 890) to $1.8 billion for years 2008 through 2023 (post Order No. 890). As of June 30, 2023, the 1,745 supplemental projects with expected in service dates between 2023 and 2027, have a total cost estimate of $19.4 billion.

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

Year	ACEC	AEP	AMPT	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	NEET	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
1998	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$1.67	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$1.67
1999	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.77	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.77
2000	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$32.94	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$32.94
2001	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$6.79	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$6.79
2002	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$7.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$7.00
2003	$7.42	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$8.77	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$9.60	$0.00	$0.00	$0.00	$0.00	$25.79
2004	$4.45	$0.00	$0.00	$10.00	$0.00	$0.00	$0.82	$0.00	$0.00	$0.00	$0.00	$7.33	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$22.60
2005	$4.06	$14.67	$0.00	$10.12	$0.00	$0.00	$2.57	$0.00	$0.00	$0.00	$0.02	$10.99	$0.00	$0.00	$0.00	$0.00	$0.00	$0.50	$0.00	$0.00	$0.00	$0.00	$0.00	$42.93
2006	$4.03	$309.70	$0.00	$0.94	$0.00	$0.00	$48.93	$0.00	$0.00	$0.00	$0.00	$11.62	$0.00	$6.00	$0.00	$0.00	$0.00	$0.00	$1.50	$0.00	$4.63	$18.80	$0.00	$406.15
2007	$0.56	$2.06	$0.00	$9.85	$0.00	$37.61	$4.65	$0.00	$0.00	$31.75	$0.00	$9.72	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.34	$2.28	$0.00	$98.82
2008	$2.36	$0.00	$0.00	$12.03	$0.00	$0.45	$7.61	$0.00	$0.00	$7.00	$14.01	$2.27	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$1.60	$0.00	$0.00	$47.33
2009	$0.77	$0.90	$0.00	$12.22	$0.00	$5.00	$21.11	$0.00	$0.00	$19.60	$2.12	$7.36	$0.00	$0.00	$0.00	$0.00	$0.00	$48.10	$2.73	$0.00	$0.16	$17.60	$0.00	$137.67
2010	$0.00	$34.36	$0.00	$12.13	$0.00	$18.90	$1.38	$0.00	$0.00	$34.45	$14.98	$0.00	$0.00	$0.03	$4.58	$0.00	$0.00	$31.80	$0.00	$0.00	$1.86	$17.72	$0.00	$172.19
2011	$0.00	$37.60	$0.00	$9.30	$0.00	$0.00	$1.00	$0.00	$0.00	$16.72	$85.67	$0.00	$0.00	$1.16	$0.00	$0.00	$0.00	$113.30	$0.00	$0.00	$11.87	$34.60	$0.00	$311.22
2012	$0.00	$46.00	$0.00	$5.12	$0.35	$2.20	$12.60	$0.00	$26.06	$11.60	$165.74	$0.99	$0.00	$6.61	$0.00	$0.00	$0.00	$12.60	$0.00	$0.00	$19.66	$223.01	$0.00	$532.54
2013	$3.15	$134.93	$0.00	$1.10	$33.68	$0.00	$59.25	$0.00	$9.93	$79.10	$25.03	$0.99	$0.00	$0.05	$4.10	$0.00	$0.00	$22.50	$0.00	$2.40	$76.70	$503.72	$0.00	$956.63
2014	$8.03	$387.00	$0.00	$5.97	$58.70	$21.20	$60.37	$0.00	$2.43	$14.90	$88.61	$5.96	$0.72	$5.60	$0.00	$0.00	$0.00	$13.30	$1.30	$0.00	$33.47	$309.71	$0.00	$1,017.27
2015	$3.73	$237.45	$0.00	$3.80	$21.90	$2.00	$376.00	$0.00	$14.12	$4.53	$113.53	$13.06	$1.22	$0.30	$0.00	$0.00	$0.00	$33.80	$0.00	$42.50	$50.17	$743.91	$0.00	$1,662.02
2016	$74.54	$84.13	$0.00	$18.40	$182.70	$0.00	$308.15	$0.00	$15.13	$26.95	$40.68	$26.60	$0.25	$0.00	$2.37	$0.00	$0.00	$86.40	$0.40	$7.80	$58.76	$744.18	$0.00	$1,677.44
2017	$66.28	$648.74	$0.00	$8.60	$164.45	$0.09	$145.97	$0.00	$64.31	$3.62	$104.25	$92.29	$2.21	$0.00	$14.70	$0.00	$0.00	$0.00	$8.30	$12.00	$264.34	$988.92	$0.00	$2,589.07
2018	$66.55	$816.23	$0.00	$14.60	$42.12	$4.08	$80.94	$0.00	$69.80	$3.13	$162.94	$68.94	$10.87	$0.00	$0.00	$0.00	$0.00	$47.60	$0.00	$156.00	$197.34	$631.25	$0.00	$2,372.39
2019	$64.30	$1,163.04	$0.00	$11.97	$190.40	$76.55	$90.19	$0.30	$90.69	$0.30	$90.14	$33.55	$23.67	$0.90	$62.30	$0.00	$0.00	$2.00	$75.80	$0.00	$298.00	$356.41	$0.00	$2,630.51
2020	$59.58	$920.44	$0.00	$0.30	$112.78	$62.58	$78.09	$13.66	$72.06	$6.40	$258.72	$39.50	$25.61	$2.60	$23.10	$0.00	$0.00	$2.40	$74.50	$102.70	$215.29	$1,861.58	$0.00	$3,931.89
2021	$86.54	$982.77	$0.00	$9.50	$184.21	$32.85	$125.70	$26.10	$117.39	$18.90	$98.40	$0.00	$25.67	$46.70	$85.89	$0.00	$0.00	$74.44	$63.48	$0.00	$197.67	$483.34	$0.00	$2,659.55
2022	$81.40	$624.58	$0.00	$18.88	$258.13	$203.30	$147.60	$36.05	$63.58	$45.00	$180.40	$9.38	$27.00	$30.50	$131.58	$0.00	$0.00	$73.68	$68.01	$2.79	$213.97	$423.43	$0.00	$2,639.26
2023	$185.45	$1,929.02	$27.20	$8.64	$174.21	$0.00	$34.30	$63.07	$120.13	$0.00	$297.45	$72.90	$36.29	$1.00	$256.96	$51.90	$4.40	$191.60	$85.70	$4.02	$176.28	$940.89	$0.00	$4,661.41
2024	$76.01	$2,364.97	$0.00	$21.24	$111.83	$118.00	$241.90	$92.20	$42.10	$3.25	$531.28	$87.80	$32.10	$95.90	$115.76	$0.00	$0.00	$0.00	$75.80	$809.47	$241.50	$321.01	$0.00	$5,382.12
2025	$213.99	$1,724.53	$80.20	$60.00	$717.90	$144.10	$115.40	$57.40	$38.40	$34.00	$626.18	$51.40	$3.80	$0.00	$154.80	$0.00	$0.00	$3.80	$103.80	$0.50	$428.90	$407.03	$0.00	$4,966.13
2026	$95.50	$647.60	$0.00	$0.00	$187.76	$687.25	$161.00	$30.10	$23.80	$0.00	$252.00	$58.78	$21.90	$24.00	$33.30	$0.00	$0.00	$0.00	$41.10	$0.00	$258.00	$404.50	$0.00	$2,926.59
2027	$17.13	$554.85	$0.00	$0.00	$157.30	$0.00	$0.00	$22.60	$30.62	$160.00	$179.90	$6.10	$28.01	$0.00	$10.00	$0.00	$0.00	$0.00	$0.00	$0.00	$83.80	$180.80	$0.00	$1,431.11
2028	$0.00	$398.94	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$26.50	$30.40	$7.59	$15.00	$30.78	$0.00	$0.00	$0.00	$0.00	$71.00	$140.10	$0.00	$112.26	$0.00	$0.00	$832.57
2029	$0.00	$0.00	$0.00	$0.00	$10.00	$276.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$136.39	$0.00	$0.00	$422.39
2030	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$200.00	$0.00	$181.88	$0.00	$0.00	$381.88
2031	$0.00	$0.00	$0.00	$0.00	$80.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$192.80	$0.00	$0.00	$272.80
2032	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$154.80	$0.00	$0.00	$154.80
2033	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$116.28	$0.00	$0.00	$116.28
2034	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$443.00	$0.00	$0.00	$0.00	$0.00	$443.00
2035	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2036	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2037	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2038	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2039	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2040	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total	$1,125.83	$14,064.51	$107.40	$264.71	$2,688.42	$1,692.16	$2,125.53	$341.48	$827.05	$551.60	$3,339.64	$690.47	$270.10	$221.35	$899.44	$51.90	$4.40	$828.82	$1,395.12	$1,140.18	$3,728.72	$9,614.69	$0.00	$45,973.52

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

End of Life Transmission Projects

An end of life transmission project is a project submitted for the purpose of replacing existing infrastructure that is at, or is approaching, the end of its useful life. Under the current process, end of life transmission projects are not subject to the RTEP open window process and have become a form of supplemental project that is exempt from competition under the existing rules.[95]

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

Competitive Planning Process Exclusions

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

- **Immediate Need Exclusion.** Due to the immediate need of the violation (3 years or less), the timing required for an RTEP proposal window is defined to be infeasible and such projects are excluded from competition. As a result, the local Transmission Owner is the Designated Entity.[96] On October 17, 2019, the Commission issued an Order Instituting Section 206 Proceedings to determine if RTOs have implemented the exemption in a manner consistent with the Commission's directives under Order 1000.[97] 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.[98] 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.[99] The decision was largely based on deference to FERC expertise.[100]
- **Below 200kV.** Due to the lower voltage level of the identified violation(s), the driver(s) for this project are excluded from competition. As a result, the local Transmission Owner is the Designated Entity.[101] Some supplemental projects are in this category.
- **Substation Equipment.** Due to identification of the limiting element(s) as substation equipment, such projects are excluded from competition. As a result, the local Transmission Owner is the Designated Entity.[102] Some supplemental projects are in this category.

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

Dominion Data Center Alley Immediate Need

An area in northern Virginia in the Dominion Transmission Zone, known as Data Center Alley, has experienced significant load growth due to increases in customer requests for data centers in the area. As a result, Dominion has presented 44 supplemental project requests to serve the increase in load through the summer of 2025. As part of the supplemental planning process, PJM performs a do no harm analysis. PJM has identified the need for additional baseline reinforcements to support the load growth. "Due to the pace and magnitude of load increase in the data center alley area, current operational

95 In recent decisions addressing competing proposals on end of life projects, the Commission accepted a transmission owner proposal excluding end of life projects from competition in the RTEP process, 172 FERC ¶ 61,136 (2020), *reh'g denied*, 173 FERC ¶ 61,225 (2020), and rejected a proposal from PJM stakeholders that would have included end of life projects in competition in the RTEP process, 173 FERC ¶ 61,242 (2020).
96 See OA Schedule 6 § 1.5.8(m).
97 169 FERC ¶ 61,054 (2019).
98 LSP Transmission Holdings II, LLC v. FERC, 45 F.4th 979.
99 *Id.* at 999.
100 *Id.*
101 See OA Schedule 6 § 1.5.8(n).
102 See OA Schedule 6 § 1.5.8(p).

and reliability constraints on the transmission system to serve load and consideration that a shortened competitive window will lead to delays of about 6 months, PJM has determined to designate Dominion construction responsibility to mitigate these immediate need violations."[103] [104] The proposed solution includes 500kV and 230kV lines extensions, the reconductoring of multiple 230kV lines and substation work. The initial cost estimate for the scope of work is $627.6 million.[105]

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.[106]

The 2020 RTEP Window 1 was the first open window that received cost capping proposals to be evaluated under the comparative cost framework. PJM has not provided the requested data to the MMU to allow for an analysis of their financial review process. Without this analysis, the MMU cannot verify that the analysis performed under the comparative cost framework was sufficient or adequately followed the process defined in the PJM manual.[107] The existing proposal templates do not provide enough information to adequately perform a financial analysis. The MMU recommends that PJM modify the project proposal templates to include data necessary to perform a detailed project lifetime financial analysis. The required data includes, but is not limited to: capital expenditure; capital structure; return on equity; cost of debt; tax assumptions; ongoing capital expenditures; ongoing maintenance; and expected life.

Storage As A Transmission Asset (SATA)

The PJM Planning Committee is currently considering whether storage devices should be included in the RTEP process as transmission assets.[108]

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.[109] 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.[110]

103 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>.
104 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>.
105 See "Reliability Analysis Update Immediate Need," presented at the September 6, 2022 meeting of the Transmission Expansion Advisory Committee. <https://www.pjm.com/-/media/committees-groups/committees/teac/2022/20220906/item-09a---reliability-analysis-update---immediate-need.ashx>.
106 170 FERC ¶ 61,243 (2020).
107 See "PJM Manual 14F: Competitive Planning Process," Rev. 9 (April 27, 2022).
108 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>.
109 See *AEP*, Docket No. EL20-58 (July 22, 2020).
110 173 FERC ¶ 61,264 (2020).

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

Board Authorized Transmission Upgrades

The Transmission Expansion Advisory Committee (TEAC) regularly reviews internal and external proposals to improve transmission reliability throughout PJM. These proposals, which include reliability baseline, network, market efficiency and targeted market efficiency projects, as well as scope changes and project cancellations, but exclude supplemental and end of life projects, are periodically presented to the PJM Board of Managers for authorization.[111]

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 six months of 2023, the PJM Board approved a net change of $559.3 million in transmission upgrades. On February 15, 2023, the PJM Board authorized $645.2 million in transmission upgrades and additions. On April 11, 2023, the PJM Board authorized a net reduction of $85.5 million in transmission upgrades and additions. The net reduction was a result of an additional $101.5 million in new baseline projects and $187.0 million in baseline projects cancelled due to the withdrawal of several nuclear and coal deactivation requests. As of June 30, 2023, the PJM Board had approved $42.1 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 June 30, 2023, no QTUs have cleared a BRA or IA.

Cost Allocation

In response to complaints against PJM RTEP Baseline Upgrade Filings in 2014 that included cost allocations for $1.5 billion in baseline transmission enhancements and expansions, on November 24, 2015, FERC issued an order directing investigation of "whether there is a definable category of reliability projects within PJM for which the solution-based DFAX cost allocation method may not be just and reasonable, such as projects addressing reliability violations that are not related to flow on the planned transmission facility, and whether an alternative just and reasonable *ex ante* cost allocation method could be established for any such category of projects."[112] FERC convened a technical conference on January 12, 2016, to address the complaints in multiple proceedings and to address these two core issues.[113]

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.[114] The Commission found that PJM's solution based dfax method for

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

112 153 FERC ¶ 61,245 at P 35 (2015).
113 See Docket Nos. EL15-18-000 (ConEd), EL15-67-000 (Linden), and EL15-95-000 (Artificial Island).
114 170 FERC ¶ 61,122 (2020).

regional cost allocation, including the 0.01 distribution cutoff factor, is just and reasonable.

On appeal, the U.S. Court of Appeals for the D.C. Circuit found that FERC had failed to explain its distinction between the projects eligible to use the dfax method and those not eligible.[115] 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."[116] The Court also rejected the 0.01 distribution cutoff factor as "absurd."[117] The Court remanded issues concerning PJM's solution based dfax method to FERC, where the matter is now pending.[118]

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

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

115 See *Consolidated Edison v. FERC et al.*, 15-1183 et al, slip. op. (D.C. Cir. August 9, 2022).
116 *Id.* at 9.
117 See *id.*
118 See FERC Docket Nos. ER22-1606-000 & EL21-39-000 (consolidated).

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 impact 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. Congestion costs were significantly higher during extreme winter weather conditions such as January 2014, when the congestion costs in PJM were $825.1 million for one month.[119]

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

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

Transmission line ratings can result in short term, significant increases in prices as a result of the application of transmission penalty factors. For example, violation of a transmission constraint, meaning that the flow exceeds the line limit, generally results in at least a $2,000 per MWh price. As the power flows approach their rated limits, PJM dispatchers often reduce the limits.[120] Violation of these reduced line ratings results in penalty factors setting prices. In 2021, there were 170,067 transmission constraint intervals in the real-time market with a nonzero shadow price. For nearly eight percent of these transmission constraint intervals, the line limit was violated, meaning that the flow exceeded the facility limit. In 2021, the average shadow price of transmission constraints when the line limit was violated was nearly 8.8 times higher than when the transmission constraint was binding at its limit.[121]

Capacity market prices separate locally when transmission capability into Locational Deliverable Areas (LDA) is not adequate to meet the LDA capacity requirement with the lowest cost capacity. The available transmission capability into LDAs is defined as the Capacity Emergency Transfer Limit (CETL). Higher cost LDAs are the equivalent in the capacity market of congestion in the energy market. Load in the higher cost LDAs pay more for capacity than those in lower cost LDAs. For example, the clearing price for the BGE LDA in the 2021/2022 Base Residual Auction was $200.30 per MW-day. The clearing price for the EMAAC LDA was $165.73 per MW-day.[122]

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.[123] 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.[124]

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,

120 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>.

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

122 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).

123 See "PJM Manual 3: Transmission Operations," Rev. 64 (May 31, 2023) § 2.1.1, at p 27.

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

line ratings should be updated in real time to reflect real time conditions and to help ensure that real-time prices are based on actual current line ratings. New technologies that permit dynamic line ratings (DLR) should be implemented.

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

Given the significant impact of transmission line ratings on all aspects of wholesale power markets, ensuring and improving the accuracy and transparency of line ratings is essential. Line ratings should incorporate ambient temperature conditions, wind speed and other relevant operating conditions. In PJM, real-time prices are calculated every five minutes for thousands of nodes. PJM prices are extremely sensitive to transmission line ratings.

The MMU recommends that all PJM transmission owners use the same methods to define line ratings and implement dynamic line ratings (DLR), subject to NERC standards and guidelines, subject to review by NERC, PJM and the MMU, and approval by FERC. The same facilities should have the same basic ratings under the same operating conditions regardless of the transmission owner. Transmission owner discretion should be minimized or eliminated. The line rating methods should be based on the basic engineering facts of the transmission system components and reflect the impact of actual operating conditions on the ratings of transmission facilities, including ambient temperatures and wind speed when relevant.[125] The line rating methods should be public and fully transparent.

125 *See* "Transmission Owner Ratings Development and Reporting in PJM," presented at May 3, 2018 meeting of the Planning Committee.

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.[126] All line rating changes and the detailed reasons for those changes should be public and fully transparent.

The Commission recently adopted rules that enhance the ability of PJM and the MMU to understand and monitor line ratings on the PJM grid. Order No. 881, issued December 16, 2021, requires that: transmission providers implement ambient-adjusted ratings on transmission lines; RTOs/ISOs implement the systems and procedures necessary for hourly ratings updates; transmission providers use uniquely determined emergency ratings; 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.[127] [128]

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."[129]

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.

126 *See* the *2018 State of the Market Report for PJM*, Volume II, Section 2: Recommendations.
127 *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").
128 *See* 18 CFR § 35.28(c)(5)&(g)(13).
129 Order No. 881-A at P 91.

Order No. 881 did not require the use of dynamic line ratings ("DLR") based on an insufficient record.[130] But, on February 17, 2022, in Docket No. AD22-5, FERC issued a notice of inquiry addressing the DLR issues.[131]

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

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

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

130 Order No. 881 at PP 25, 254
131 *Implementation of Dynamic Line Ratings*, Notice of Inquiry, 178 FERC ¶ 61,110 (2022).

Transmission Facility Outages

Scheduling Transmission Facility Outage Requests

A transmission facility is designated as reportable by PJM if a change in its status can affect a transmission constraint on any Monitored Transmission Facility or could impede free flowing ties within the PJM RTO and/or adjacent areas.[132] 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.[133] The specific timeline is shown in Table 12-57.[134]

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

The outage data for the FTR market are for outages scheduled to occur in the 2021/2022 planning period and the first ten months of the 2022/2023 planning period, regardless of when they were initially submitted.[135] The outage data for the day-ahead market are for outages scheduled to occur from January 2015 through May 2023.

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.[136] Table 12-56 shows that 77.5 percent of requested outages were planned for less than or equal to five days and 8.2 percent of requested outages were planned for greater than 30 days in the 2022/2023 planning period. Table 12-56 also shows that 77.3 percent of the requested outages were planned for less than or equal to five days and 8.1 percent of requested outages were planned for greater than 30 days in the 2021/2022 planning period.

132 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. 64 (May 31, 2023S.
133 See PJM, "Manual 3: Transmission Operations," Rev. 64 (May 31, 2023).
134 See PJM, "Manual 3: Transmission Operations," Rev. 64 (May 31, 2023).
135 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.
136 *Id.* at 70.

Table 12-56 Transmission facility outage request summary by planned duration: June 2021 through May 2023

	2021/2022 (12 months)		2022/2023 (12 months)	
Planned Duration (Days)	Outage Requests	Percent of Total	Outage Requests	Percent of Total
<=5	15,182	77.3%	15,281	77.5%
>5 & <=30	2,869	14.6%	2,819	14.3%
>30	1,587	8.1%	1,614	8.2%
Total	19,638	100.0%	19,714	100.0%

After receiving a transmission facility outage request from a TO, PJM assigns a received status to the request based on its submission date and outage planned duration. The received status can be On Time or Late, as defined in Table 12-57.[137]

The purpose of the rules defined in Table 12-57 is to require the TOs to submit transmission facility outages prior to the Financial Transmission Right (FTR) auctions so that market participants have complete information about market conditions on which to base their FTR bids and PJM can accurately model market conditions.[138]

Table 12-57 Transmission facility outage request received status definition

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

Table 12-58 shows a summary of requests by received status. In the 2022/2023 planning period, 37.5 percent of outage requests received were late. In the 2021/2022 planning period, 40.1 percent of outage requests received were late.

Table 12-58 Transmission facility outage requests by received status: June 2021 through May 2023

	2021/2022 (12 months)				2022/2023 (12 months)			
Planned Duration (Days)	On Time	Late	Total	Percent Late	On Time	Late	Total	Percent Late
<=5	9,607	5,575	15,182	36.7%	10,144	5,137	15,281	33.6%
>5 & <=30	1,555	1,314	2,869	45.8%	1,532	1,287	2,819	45.7%
>30	602	985	1,587	62.1%	649	965	1,614	59.8%
Total	11,764	7,874	19,638	40.1%	12,325	7,389	19,714	37.5%

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.[139]

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.[140] Table 12-59 is a summary of outage requests by emergency status. Of all outage requests scheduled to occur in the 2022/2023 planning period, 11.5 percent were for emergency outages. Of all outage requests scheduled to occur in the 2021/2022 planning period, 12.1 percent were for emergency outages.

137 See PJM, "Manual 3: Transmission Operations," Rev. 64 (May 31, 2023).
138 See "Report of PJM Interconnection, L.L.C. on Transmission Oversight Procedures," Docket No. EL01-122-000 (November 2, 2001).

139 See PJM, "Manual 3: Transmission Operations," Rev. 64 (May 31, 2023). 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).
140 PJM, "Manual 3: Transmission Operations," Rev. 64 (May 31, 2023).

Table 12-59 Transmission facility outage requests by emergency: June 2021 through May 2023

	2021/2022 (12 months)				2022/2023 (12 months)			
Planned Duration (Days)	Emergency	Non Emergency	Total	Percent Emergency	Emergency	Non Emergency	Total	Percent Emergency
<=5	1,748	13,434	15,182	11.5%	1,648	13,633	15,281	10.8%
>5 & <=30	356	2,513	2,869	12.4%	348	2,471	2,819	12.3%
>30	269	1,318	1,587	17.0%	270	1,344	1,614	16.7%
Total	2,373	17,265	19,638	12.1%	2,266	17,448	19,714	11.5%

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."[141]

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

Table 12-60 is a summary of outage requests by congestion status. Of all outage requests submitted to occur in the 2022/2023 planning period, 7.5 percent were expected to cause congestion. Of all the outage requests that were expected to cause congestion, 3.9 percent (46 out of 1,481) were denied by PJM in the 2022/2023 planning period and 20.5 percent (304 out of 1,481) were cancelled (Table 12-62). Of all outage requests submitted to occur in the 2021/2022 planning period, 6.3 percent were expected to cause congestion. Of all the outage requests that were expected to cause congestion, 3.8 percent (47 out of 1,236) were denied by PJM in the 2021/2022 planning period and 19.6 percent (242 out of 1,236) were cancelled (Table 12-62).

Table 12-60 Transmission facility outage requests by congestion: June 2021 through May 2023

	2021/2022 (12 months)				2022/2023 (12 months)			
Planned Duration (Days)	Congestion Expected	No Congestion Expected	Total	Percent Congestion Expected	Congestion Expected	No Congestion Expected	Total	Percent Congestion Expected
<=5	918	14,264	15,182	6.0%	1,065	14,216	15,281	7.0%
>5 & <=30	211	2,658	2,869	7.4%	288	2,531	2,819	10.2%
>30	107	1,480	1,587	6.7%	128	1,486	1,614	7.9%
Total	1,236	18,402	19,638	6.3%	1,481	18,233	19,714	7.5%

Table 12-61 shows the outage requests summary by received status, congestion status and emergency status. In the 2022/2023 planning period, 26.1 percent of requests were submitted late and were nonemergency while 1.0 percent of requests (204 out of 19,714) were late, nonemergency, and expected to cause congestion. In the 2021/2022 planning period, 28.3 percent of request were submitted late and were nonemergency while 1.1 percent of requests (221 out of 19,638) were late, nonemergency, and expected to cause congestion.

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

Table 12-61 Transmission facility outage requests by received status, emergency and congestion: June 2021 through May 2023

		2021/2022 (12 months)				2022/2023 (12 months)			
Received Status		Congestion Expected	No Congestion Expected	Total	Percent of Total	Congestion Expected	No Congestion Expected	Total	Percent of Total
Late	Emergency	56	2,261	2,317	11.8%	66	2,171	2,237	11.3%
	Non Emergency	221	5,336	5,557	28.3%	204	4,948	5,152	26.1%
On Time	Emergency	8	48	56	0.3%	7	22	29	0.1%
	Non Emergency	951	10,757	11,708	59.6%	1,204	11,092	12,296	62.4%
Total		1,236	18,402	19,638	100.0%	1,481	18,233	19,714	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.[142] Table 12-62 shows the detailed process status for outage requests only for the outage requests that are expected to cause congestion. Status Submitted and status Received are in the In Process category and status Cancelled by Company and status PJM Admin Closure are in the Cancelled category in Table 12-62. Table 12-62 shows that of all the outage requests that were expected to cause congestion, 3.9 percent (46 out of 1,481) were denied by PJM in the 2022/2023 planning period, 68.7 percent were complete and 20.5 percent (304 out of 1,481) were cancelled. Of all the outage requests that were expected to cause congestion, 3.8 percent (47 out of 1,236) were denied by PJM in the 2021/2022 planning period, 67.6 percent were complete and 19.6 percent (242 out of 1,236) were cancelled.

Table 12-62 Transmission facility outage requests by processed status[143]: June 2021 through May 2023

		2021/2022 (12 months)						2022/2023 (12 months)					
Received Status		Cancelled	Complete	In Process	Denied	Congestion Expected	Percent Complete	Cancelled	Complete	In Process	Denied	Congestion Expected	Percent Complete
Late	Emergency	7	47	0	1	56	83.9%	3	63	0	0	66	95.5%
	Non Emergency	36	159	3	22	221	71.9%	32	155	7	8	204	76.0%
On Time	Emergency	2	6	0	0	8	75.0%	0	7	0	0	7	100.0%
	Non Emergency	197	624	93	24	951	65.6%	269	793	97	38	1,204	65.9%
Total		242	836	96	47	1,236	67.6%	304	1,018	104	46	1,481	68.7%

There are clear rules defined for assigning On Time or Late status for submitted outage requests in both the PJM tariff and PJM manuals.[144] The On Time or Late status affects the way in which PJM addresses the potential to exceed transmission limits. Table 12-62 shows that in the 2021/2022 planning period, 221 nonemergency outage requests were submitted late and expected to cause congestion. The expected impact on congestion and the options for controlling that congestion is the basis for PJM's treatment of late outage requests. But 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

142 See PJM Markets & Operations, PJM Tools "Outage Information," <http://www.pjm.com/markets-and-operations/etools/oasis/system-information/outage-info.aspx> (2019).
143 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.
144 OA Schedule 1 § 1.9.2.

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.[145]

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 12-63 is a summary of all the outage requests planned for the 2021/2022 planning period and the 2022/2023 planning period which were approved and then cancelled or rescheduled by TOs at least once. If an outage request was submitted, approved and subsequently rescheduled at least once, the outage request will be counted as Approved and Rescheduled. If an outage request was submitted, approved and subsequently cancelled at least once, the outage request will be counted as Approved and Cancelled. In the 2022/2023 planning period, 26.9 percent of transmission outage requests were approved by PJM and then rescheduled by the TOs, and 10.8 percent of the transmission outages were approved by PJM and subsequently cancelled by the TOs. In the 2021/2022 planning period, 30.2 percent of transmission outage requests were approved by PJM and then rescheduled by the TO, and 12.6 percent of the transmission outages were approved by PJM and subsequently cancelled by the TO.

Table 12-63 Rescheduled and cancelled transmission outage requests: June 2021 through May 2023

	2021/2022 (12 months)					2022/2023 (12 months)				
Planned Duration (Days)	Outage Requests	Approved and Rescheduled	Percent Approved and Rescheduled	Approved and Cancelled	Percent Approved and Cancelled	Outage Requests	Approved and Rescheduled	Percent Approved and Rescheduled	Approved and Cancelled	Percent Approved and Cancelled
<=5	15,182	3,195	21.0%	2,165	14.3%	15,281	2,850	18.7%	1,882	12.3%
>5 & <=30	2,869	1,607	56.0%	212	7.4%	2,819	1,458	51.7%	187	6.6%
>30	1,587	1,134	71.5%	91	5.7%	1,614	988	61.2%	63	3.9%
Total	19,638	5,936	30.2%	2,468	12.6%	19,714	5,296	26.9%	2,132	10.8%

145 "PJM Manual 38: Operations Planning," Rev. 16 (Jan. 25, 2023). p 20. 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."

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.[146] 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.[147] 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 12-57) define a transmission outage request as On Time or Late based on the planned outage duration and the time of submission. The rule has stricter submission requirements for transmission outage requests planned for longer than 30 days. In order to avoid the stricter submission requirement, some transmission owners divided the duration of outage requests longer than 30 days into shorter segments for the same equipment and submitted one request for each segment. The MMU recommends that PJM not permit transmission owners to divide long duration outages into smaller segments to avoid complying with the requirements for long duration outages.

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

Table 12-64 shows that there were 12,418 transmission equipment planned outages in the 2022/2023 planning period, of which 1,623 or 13.1 percent were longer than 30 days, and of which 250 or 2.0 percent were scheduled longer than 30 days when the duration of all the outage requests are combined for the same equipment.

Table 12-64 Transmission equipment outages: June 2021 through May 2023

		2021/2022 (12 months)		2022/2023 (12 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	1,377	11.3%	1,373	11.1%
	Yes	238	2.0%	250	2.0%
<= 30		10,585	86.8%	10,795	86.9%
Total		12,200	100.0%	12,418	100.0%

Table 12-65 shows the details of long duration (> 30 days) outages when combining the duration of the outage requests for the same equipment.[148] 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 2022/2023 planning period, within effective duration greater than a month and shorter than two months, there were 31 outages with a combined duration longer than 30 days.

146 PJM, "Manual 3: Transmission Operations," Rev. 64 (May 31, 2023).
147 *Id.*

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

Table 12-65 Transmission equipment outages by effective duration: June 2021 through May 2023

	2021/2022 (12 months)		2022/2023 (12 months)	
Effective Duration of Outage	Count of Equipment with Planned Outages	Percent of Total	Count of Equipment with Planned Outages	Percent of Total
<=31	3	1.3%	3	1.2%
>31 & <=62	29	12.2%	31	12.4%
>62 & <=93	20	8.4%	23	9.2%
>93	186	78.2%	193	77.2%
Total	238	100.0%	250	100.0%

Transmission Facility Outage Analysis for the FTR Market

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

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

Annual FTR Market

The Annual FTR Market includes the Annual ARR Allocation and the Annual FTR Auction. When determining transmission outages to be modeled in the simultaneous feasibility test used in the Annual FTR Market, PJM considers all outages with planned duration longer than or equal to two weeks as an initial list. Then PJM may exercise significant discretion in selecting outages to be modeled in the final model. PJM posts the final FTR outage list to the FTR web page usually at least one week before the auction bidding opening day.[149]

In the 2022/2023 planning period, 333 outage requests were included in the annual FTR market outage list and 19,381 outage requests were not included.[150] In the 2021/2022 planning period, 375 outage requests were included in the annual FTR market outage list and 19,263 outage requests were not included. Table 12-66, Table 12-67, Table 12-68 and Table 12-69 show the summary information on the modeled outage requests and Table 12-70 and Table 12-71 show the summary information on outages that were not included in the Annual FTR Market.

Table 12-66 shows that 21.9 percent of the outage requests modeled in the Annual FTR Market for the 2022/2023 planning period had a planned duration of less than two weeks and that 15.3 percent of the outage requests (51 out of 333) modeled in the Annual FTR Market for the planning period were submitted late according to outage submission rules. It also shows that 28.0 percent of the outage requests modeled in the Annual FTR Market for the 2021/2022 planning period had a planned duration of less than two weeks and that 16.8 percent of the outage requests (63 out of 375) modeled in the Annual FTR Market for the planning period were submitted late according to outage submission rules.

Table 12-66 Annual FTR market modeled transmission facility outage requests by received status: June 2021 through May 2023

	2021/2022 (12 months)				2022/2023 (12 months)			
Planned Duration	On Time	Late	Total	Percent of Total	On Time	Late	Total	Percent of Total
<2 weeks	90	15	105	28.0%	67	6	73	21.9%
>=2 weeks & <2 months	128	17	145	38.7%	99	12	111	33.3%
>=2 months	94	31	125	33.3%	116	33	149	44.7%
Total	312	63	375	100.0%	282	51	333	100.0%

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

149 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.

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

Table 12-67 Annual FTR market modeled transmission facility outage requests by emergency: June 2021 through May 2023

		2021/2022 (12 months)				2022/2023 (12 months)			
Received Status	Planned Duration	Emergency	Non Emergency	Total	Percent Non Emergency	Emergency	Non Emergency	Total	Percent Non Emergency
On Time	<2 weeks	0	90	90	100.0%	0	67	67	100.0%
	>=2 weeks & <2 months	0	128	128	100.0%	0	99	99	100.0%
	>=2 months	0	94	94	100.0%	1	115	116	99.1%
	Total	0	312	312	100.0%	1	281	282	99.6%
Late	<2 weeks	0	15	15	100.0%	1	5	6	83.3%
	>=2 weeks & <2 months	0	17	17	100.0%	0	12	12	100.0%
	>=2 months	0	31	31	100.0%	2	31	33	93.9%
	Total	0	63	63	100.0%	3	48	51	94.1%

PJM determines expected congestion for both On Time and Late outage requests. A Late outage request may be denied or cancelled if it is expected to cause congestion. Table 12-68 shows a summary of requests by expected congestion and received status. Of all the annual FTR market modeled outages expected to occur in the 2022/2023 planning period and submitted late, 13.7 (7 out of 51) was expected to cause congestion. Overall, of all the annual FTR market modeled outages expected to occur in the 2021/2022 planning period and submitted late, 20.6 percent (13 out of 63) were expected to cause congestion.

Table 12-68 Annual FTR market modeled transmission facility outage requests by congestion: June 2021 through May 2023

		2021/2022 (12 months)				2022/2023 (12 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	16	74	90	17.8%	17	50	67	25.4%
	>=2 weeks & <2 months	35	93	128	27.3%	16	83	99	16.2%
	>=2 months	19	75	94	20.2%	31	85	116	26.7%
	Total	70	242	312	22.4%	64	218	282	22.7%
Late	<2 weeks	2	13	15	13.3%	0	6	6	0.0%
	>=2 weeks & <2 months	7	10	17	41.2%	2	10	12	16.7%
	>=2 months	4	27	31	12.9%	5	28	33	15.2%
	Total	13	50	63	20.6%	7	44	51	13.7%

Table 12-69 shows that 26.1 percent of outage requests modeled in the annual FTR market for the 2022/2023 planning period and with a duration of two weeks or longer but shorter than two months were cancelled after the FTR auction was open, compared to 20.0 percent for the 2021/2022 planning period. Table 12-69 also shows that 19.5 percent of outages requests modeled in the Annual FTR Market for the first ten months of the 2022/2023 planning period and with a duration of two months or longer were cancelled, compared to 20.0 percent for the 2021/2022 planning period.

Table 12-69 Annual FTR market modeled transmission facility outage requests by processed status: June 2021 through May 2023

		2021/2022 (12 months)		2022/2023 (12 months)	
Planned Duration	Processed Status	Outage Requests	Percent	Outage Requests	Percent
<2 weeks	In Progress	11	10.5%	5	6.8%
	Denied	1	1.0%	0	0.0%
	Approved	1	1.0%	2	2.7%
	Cancelled	28	26.7%	29	39.7%
	Revised	0	0.0%	0	0.0%
	Active	0	0.0%	0	0.0%
	Completed	64	61.0%	37	50.7%
	Total	105	100.0%	73	100.0%
>=2 weeks & <2 months	In Progress	28	19.3%	17	15.3%
	Denied	1	0.7%	0	0.0%
	Approved	0	0.0%	0	0.0%
	Cancelled	29	20.0%	29	26.1%
	Revised	1	0.7%	0	0.0%
	Active	0	0.0%	0	0.0%
	Completed	86	59.3%	65	58.6%
	Total	145	100.0%	111	100.0%
>=2 months	In Progress	10	8.0%	23	15.4%
	Denied	0	0.0%	0	0.0%
	Approved	3	2.4%	2	1.3%
	Cancelled	25	20.0%	29	19.5%
	Revised	0	0.0%	0	0.0%
	Active	2	1.6%	14	9.4%
	Completed	85	68.0%	81	54.4%
	Total	125	100.0%	149	100.0%
Total Cancelled		82	21.9%	87	26.1%
Grand Total		375		333	

More outage requests were not modeled in the Annual FTR Market than were modeled in the Annual FTR Market. In the 2022/2023 planning period, 333 outage requests were modeled and 19,381 outage requests were not modeled in the Annual FTR Market. In the 2021/2022 planning period, 375 outage requests were modeled and 19,263 outage requests were not modeled in the Annual FTR Market.

Table 12-70 shows that 11.7 percent of outage requests not modeled in the Annual FTR Auction with duration longer than or equal to two months, labeled On Time according to the rules, were submitted or rescheduled after the Annual FTR Auction bidding opening date for the 2022/2023 planning period compared to 13.6 percent in the 2021/2022 planning period.

Table 12-70 Transmission facility outage requests not modeled in Annual FTR Auction: June 2021 through May 2023

	2021/2022 (12 months)						2022/2023 (12 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	1,922	8,363	81.3%	217	6,101	96.6%	1,936	8,882	82.1%	207	5,679	96.5%
>=2 weeks & <2 months	635	356	35.9%	128	795	86.1%	709	286	28.7%	132	724	84.6%
>=2 months	152	24	13.6%	197	373	65.4%	203	27	11.7%	225	371	62.2%
Total	2,709	8,743	76.3%	542	7,269	93.1%	2,848	9,195	76.4%	564	6,774	92.3%

Table 12-71 shows that 89.2 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 2022/2023 planning period. It also shows that 91.2 percent of late outage requests which were not modeled in the Annual FTR Auction with duration longer than or equal to two months and submitted after the Annual FTR Auction bidding opening date were active or completed in the 2021/2022 planning period.

Table 12-71 Late transmission facility outage requests: June 2021 through May 2023

	2021/2022 (12 months)			2022/2023 (12 months)		
Planned Duration	Completed Outages	Total	Percent Complete	Completed Outages	Total	Percent Complete
<2 weeks	5,285	6,101	86.6%	4,930	5,679	86.8%
>=2 weeks & <2 months	696	795	87.5%	607	724	83.8%
>=2 months	340	373	91.2%	331	371	89.2%
Total	6,321	7,269	87.0%	5,868	6,774	86.6%

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.[151] Table 12-72 and Table 12-73 show the summary information on outage requests modeled in the Monthly Balance of Planning Period FTR Auction and Table 12-74 and Table 12-75 show the summary information on

151 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 12-72 shows that on average, 27.0 percent of the outage requests modeled in the Monthly Balance of Planning Period FTR Auction were submitted late according to outage submission rules in the 2022/2023 planning period. On average, 33.1 percent of the outage requests modeled in the Monthly Balance of Planning Period FTR Auction were submitted late according to outage submission rules in the 2021/2022 planning period.

Table 12-72 Monthly Balance of Planning Period FTR Auction modeled transmission facility outage requests by received status: June 2021 through May 2023

	2021/2022				2022/2023			
Month	On Time	Late	Total	Percent Late	On Time	Late	Total	Percent Late
Jun	209	116	325	35.7%	246	101	347	29.1%
Jul	103	85	188	45.2%	147	87	234	37.2%
Aug	125	81	206	39.3%	160	85	245	34.7%
Sep	363	147	510	28.8%	483	156	639	24.4%
Oct	480	192	672	28.6%	635	203	838	24.2%
Nov	454	205	659	31.1%	531	164	695	23.6%
Dec	325	153	478	32.0%	407	127	534	23.8%
Jan	214	118	332	35.5%	224	72	296	24.3%
Feb	216	121	337	35.9%	224	93	317	29.3%
Mar	399	142	541	26.2%	450	162	612	26.5%
Apr	454	172	626	27.5%	494	162	656	24.7%
May	402	182	584	31.2%	446	125	571	21.9%
Average	312	143	455	33.1%	371	128	499	27.0%

Table 12-73 shows that on average, 19.1 percent of outage requests modeled in the Monthly Balance of Planning Period FTR Auction were cancelled in the 2022/2023 planning period. On average, 17.4 percent of outage requests modeled in the Monthly Balance of Planning Period FTR Auction were cancelled in the 2021/2022 planning period.

Table 12-73 Monthly Balance of Planning Period FTR Auction modeled transmission facility outage requests by processed status: June 2021 through May 2023

Planning Year	Month	In Process	Denied	Approved	Cancelled	Revised	Active	Complete	Total	Percent Cancelled
2021/2022	Jun	35	2	10	55	0	76	147	325	16.9%
	Jul	15	2	4	26	0	76	65	188	13.8%
	Aug	24	1	4	25	0	86	66	206	12.1%
	Sep	56	2	15	89	0	176	172	510	17.5%
	Oct	56	7	21	120	0	216	252	672	17.9%
	Nov	47	3	15	108	0	182	304	659	16.4%
	Dec	32	2	8	82	0	95	259	478	17.2%
	Jan	41	1	19	61	0	96	114	332	18.4%
	Feb	43	1	17	54	0	105	117	337	16.0%
	Mar	64	2	15	109	0	157	194	541	20.1%
	Apr	55	2	20	117	0	163	269	626	18.7%
	May	60	8	25	106	0	122	263	584	18.2%
	Average	44	3	14	79	0	129	185	455	17.4%
2022/2023	Jun	27	16	14	57	0	78	155	347	16.4%
	Jul	20	9	7	40	0	81	77	234	17.1%
	Aug	19	7	10	37	0	81	91	245	15.1%
	Sep	65	6	24	130	1	210	203	639	20.3%
	Oct	86	7	23	180	2	213	327	838	21.5%
	Nov	57	3	16	140	1	198	280	695	20.1%
	Dec	41	5	9	116	1	79	283	534	21.7%
	Jan	35	3	10	59	0	91	98	296	19.9%
	Feb	36	3	7	60	0	106	105	317	18.9%
	Mar	68	2	14	108	1	163	256	612	17.6%
	Apr	59	1	20	137	1	167	271	656	20.9%
	May	56	3	24	109	0	136	243	571	19.1%
	Average	47	5	15	98	1	134	199	499	19.1%

Table 12-74 shows that on average, 9.2 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 2022/2023 planning period, compared to 9.4 percent in the 2021/2022 planning period. On average, 59.6 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 2022/2023 planning period, compared to 61.7 percent in the 2021/2022 planning period.

Table 12-74 Transmission facility outage requests not modeled in Monthly Balance of Planning Period FTR Auction: June 2021 through May 2023

	2021/2022						2022/2023					
	On Time			Late			On Time			Late		
	Before Bidding Opening Date	After Bidding Opening Date	Percent After	Before Bidding Opening Date	After Bidding Opening Date	Percent After	Before Bidding Opening Date	After Bidding Opening Date	Percent After	Before Bidding Opening Date	After Bidding Opening Date	Percent After
Jun	776	87	10.1%	323	613	65.5%	753	163	17.8%	312	558	64.1%
Jul	349	69	16.5%	272	501	64.8%	366	82	18.3%	247	465	65.3%
Aug	365	49	11.8%	262	464	63.9%	402	73	15.4%	279	466	62.6%
Sep	933	106	10.2%	318	615	65.9%	955	66	6.5%	326	504	60.7%
Oct	1,035	77	6.9%	384	664	63.4%	1,086	76	6.5%	345	544	61.2%
Nov	860	50	5.5%	411	516	55.7%	946	77	7.5%	425	496	53.9%
Dec	673	34	4.8%	340	525	60.7%	737	59	7.4%	354	538	60.3%
Jan	561	87	13.4%	308	461	59.9%	656	45	6.4%	296	417	58.5%
Feb	696	69	9.0%	348	530	60.4%	676	50	6.9%	371	474	56.1%
Mar	1,289	78	5.7%	328	589	64.2%	1,312	81	5.8%	377	560	59.8%
Apr	1,524	119	7.2%	383	533	58.2%	1,262	102	7.5%	397	501	55.8%
May	1,187	148	11.1%	419	573	57.8%	1,315	62	4.5%	428	574	57.3%
Average	854	81	9.4%	341	549	61.7%	872	78	9.2%	346	508	59.6%

Table 12-75 shows that on average, 70.0 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 2022/2023 planning period, compared to 70.2 percent in the 2021/2022 planning period.

Table 12-75 Late transmission facility outage requests: June 2021 through May 2023

	2021/2022			2022/2023		
	Completed Outages	Total	Percent Complete	Completed Outages	Total	Percent Complete
Jun	419	613	68.4%	408	558	73.1%
Jul	371	501	74.1%	354	465	76.1%
Aug	307	464	66.2%	335	466	71.9%
Sep	408	615	66.3%	349	504	69.2%
Oct	471	664	70.9%	380	544	69.9%
Nov	347	516	67.2%	325	496	65.5%
Dec	402	525	76.6%	395	538	73.4%
Jan	301	461	65.3%	267	417	64.0%
Feb	370	530	69.8%	306	474	64.6%
Mar	407	589	69.1%	400	560	71.4%
Apr	383	533	71.9%	363	501	72.5%
May	439	573	76.6%	390	574	67.9%
Average	385	549	70.2%	356	508	70.0%

Table 12-75 shows that only 1.7 percent of all outage requests were modeled in the Annual FTR Auction in 2022/2023 planning period, and 1.9 percent were modeled in the 2021/2022 planning period. For Monthly FTR Auctions in the 2022/2023 planning period, an average of 25.3 percent of all outage requests were modeled, and 23.1 percent were modeled in the 2021/2022 planning period.

Table 12-76 FTR market modeled transmission facility outage requests: June 2021 through May 2023

	2021/2022 (12 months)			2022/2023 (10 months)		
Planned Duration	Annual Modeled	Monthly Modeled	Total	Annual Modeled	Monthly Modeled	Total
<2 weeks	105	2,720	2,825	73	3,162	3,235
>=2 weeks & <2 months	145	1,236	1,381	111	1,240	1,351
>=2 months	125	578	703	149	594	743
Total	375	4,534	4,909	333	4,996	5,329
All outage requests			19,638			19,714
Percent of Modeled	1.9%	23.1%	25.0%	1.7%	25.3%	27.0%

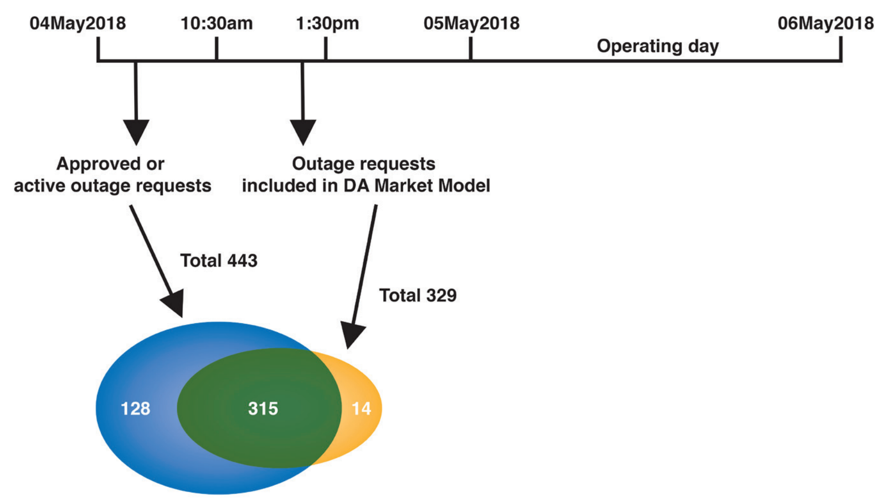
Transmission Facility Outage Analysis in the Day-Ahead Energy Market

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.[152]

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

For example for the operating day of May 5, 2018, Figure 12-7 shows that: there were 443 approved or active outages seen by market participants before the day-ahead market was closed; there were 329 outage requests included in the day-ahead market model; there were 315 outage requests included in both sets of outage; there were 128 outage requests approved or active before the day-ahead market was closed but not included as inputs in day-ahead market model; and there were 14 outage requests included in day-ahead market model but not available to market participants prior to the day-ahead market.

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



152 PJM, "Manual 3: Transmission Operations," Rev. 64 (May 31, 2023).

Figure 12-8 compares the weekly average number of active or approved outages available to market participants prior to the close of the day-ahead market with the outages included as inputs to the day-ahead market by PJM. Figure 12-8 shows that the number of outages visible to market participants but excluded in the day-ahead model has decreased significantly for the Fall and Spring outage seasons of the 2022/2023 planning period.

Figure 12-8 Approved or active outage requests: January 2015 through June 2023

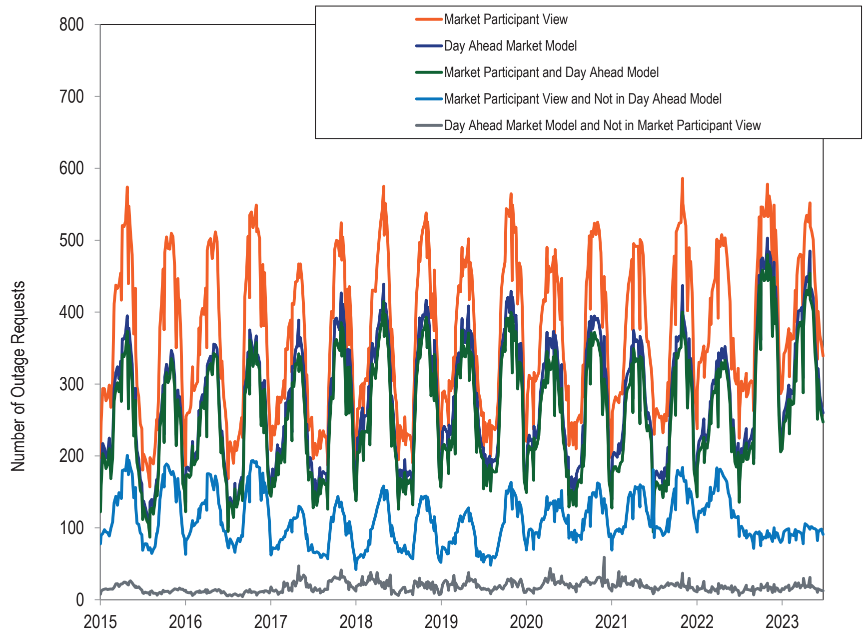


Figure 12-9 compares the weekly average number of outages included in the day-ahead market with the outages that actually occurred during the operating day. Figure 12-9 shows that starting on May 29, 2022, the weekly average number of outages included in the day-ahead market as indicated by dark blue line was consistently higher than the weekly average number of outages indicated by orange line that actually occurred through the end of June 2023.

Figure 12-9 Day-ahead market model outages: January 2015 through June 2023

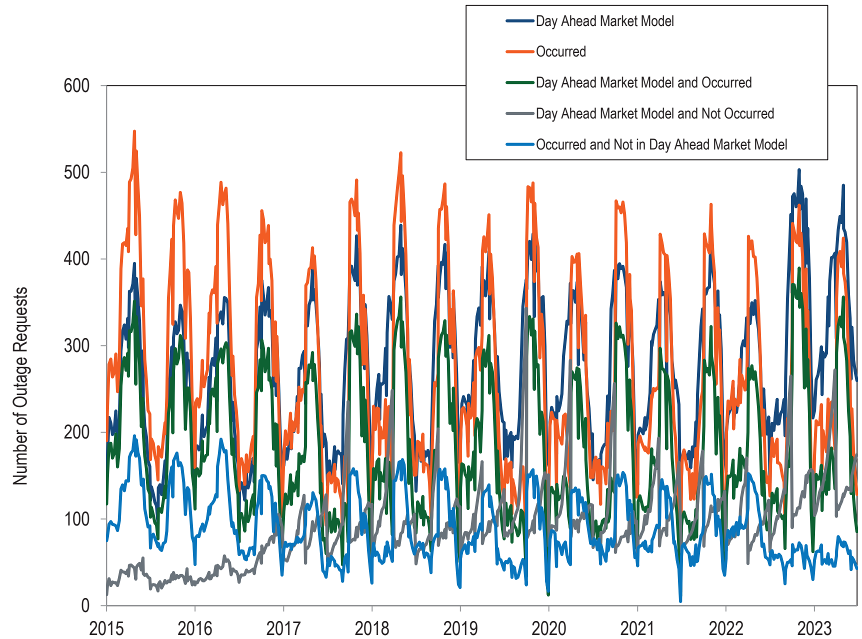


Figure 12-10 compares the weekly average number of active or approved outages for which information was available to market participants prior to the close of the day-ahead market with the outages that actually occurred during the operating day. Figure 12-4 shows a sharp quarterly increase of outages that are visible to market participants but do not occur, indicated by the lighter blue line in the last 2 weeks of June, September, December, and March beginning in 2017.

Figure 12-10 Approved or active outage requests: January 2015 through June 2023

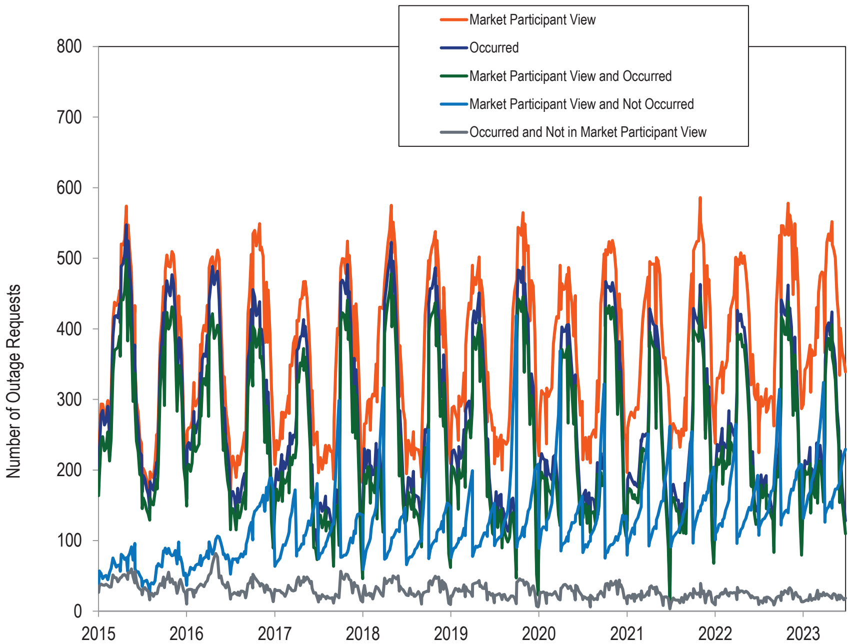


Figure 12-8, Figure 12-9, and Figure 12-10 show that on a weekly average basis, for the full year 2022, the active or approved outages for which information was available to day-ahead market participants, the outages included as inputs in the day-ahead market model and the outages that actually occurred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