Generation and Transmission Planning[1]

Overview

Planned Generation and Retirements

- **Planned Generation.** As of December 31, 2017, 99,452.5 MW of capacity were in generation request queues for construction through 2024, compared to an installed capacity of 201,496.5 MW as of December 31, 2017. Of the capacity in queues, 9,880.7 MW, or 9.9 percent, are uprates and the rest are new generation. Wind projects account for 18,287.9 MW of nameplate capacity or 18.4 percent of the capacity in the queues. Natural gas fired projects account for 59,999.8 MW of capacity or 60.3 percent of the capacity in the queues.
- **Generation Retirements.** 32,699.3 MW have been, or are planned to be, retired between 2011 and 2020. Of that, 6,935.9 MW are planned to retire after December 31, 2017. In 2017, 2,126.8 MW were retired. Of the 6,935.9 MW pending retirement, 4,620.0 MW (66.6 percent) are coal units. The coal unit retirements were a result of low gas prices, low capacity prices and the investments required for compliance with the EPA's Mercury and Air Toxics Standards (MATS) for some units.
- **Generation Mix.** A significant shift in the distribution of unit types within the PJM footprint continues as natural gas fired units enter the queue and coal fired steam units retire. There are 199.0 MW of coal fired steam capacity and 59,999.8 MW of gas fired capacity in the queue. The replacement of coal fired steam units by units burning natural gas will significantly affect future congestion, the role of firm and interruptible gas supply, and natural gas supply infrastructure.

Generation and Transmission Interconnection Planning Process

- 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.[2] PJM's process is designed to ensure that new generation is added in a reliable and systematic manner. The process is complex and time consuming at least in part as a result of the required analyses. The cost, time and uncertainty associated with interconnecting to the grid may create barriers to entry for potential entrants.
- The 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 drop out. Excluding currently active projects and projects currently under construction, 3,685 projects, representing 474,780.1 MW, have entered the queue process since its inception. Of those, 753 projects, representing 51,560.5 MW, went into service. Of the projects that entered the queue process, 68.2 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.
- Feasibility, impact and facilities studies may be delayed for reasons including disputes with developers, circuit and network issues and retooling as a result of projects being withdrawn. The Earlier Queue Submittal Task Force (EQSTF) was established in August 2015 to address delays associated with the submittal of large numbers of requests at the end of the queue window, which resulted in revisions to the PJM Open Access Transmission Tariff, effective October 31, 2016.[3] [4] On December 15, 2016, the Commission issued a notice of proposed rulemaking proposing additional queue reforms intended to improve certainty, promote more informed interconnection, and enhance interconnection processes.[5]
- 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."[6] Where

1 Totals presented in this section include corrections to historical data and may not match totals presented in previous reports.

2 See OATT Parts IV & VI.
3 See Earlier Queue Submittal Task Force at <http://www.pjm.com/committees-and-groups/closed-groups/eqstf.aspx>.
4 See Letter Order, ER16-2518-000 (Oct. 7, 2016).
5 157 FERC ¶ 61,212 (2016).
6 See OATT § 1 (Transmission Owner).

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 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 merchant transmission developer which is a competitor of the transmission owner.

Regional Transmission Expansion Plan (RTEP)

- The Transmission Expansion Advisory Committee (TEAC) regularly reviews internal and external proposals to improve transmission reliability throughout PJM. These proposals are periodically presented to the PJM Board of Managers for authorization. In 2017, the PJM Board approved over $1.7 billion in upgrades.
- There are currently three backbone projects under development, Surry Skiffes Creek 500kV, and the conversion of the Marion-Bayonne and Bayway-Linden lines from 138 kV to 345 kV.[7]
- Through December 31, 2017, PJM has completed two market efficiency cycles. In the first cycle, PJM received 92 proposals for 11 identified issues. In the second market efficiency cycle, PJM received 96 proposals for four identified issues.
- The first Targeted Market Efficiency Process (TMEP) analysis included the investigation of congestion on 50 market to market flowgates. The study resulted in the evaluation of 13 potential upgrades, resulting in the recommendation of five TMEP projects. The five projects address $59 million in historical congestion, with a TMEP benefit of $99.6 million. The projects have a total cost of $20 million, with a 5.0 average benefit/cost ratio. PJM and MISO presented the five recommended projects to their boards in December, 2017, and both boards approved all five projects.[8]
- On April 6, 2017, the PJM Board lifted the suspension of the Artificial Island project. The project is expected to be in service by June 2020.

Transmission Facility Outages

- PJM maintains a list of reportable transmission facilities. When the reportable transmission facilities need to be taken out of service, PJM transmission owners are required to report planned transmission facility outages as early as possible. PJM processes the transmission facility outage requests according to rules in PJM's Manual 3 to decide if the outage is on time or late and whether or not they will allow the outage.[9]
- There were 15,613 transmission outage requests submitted in the 2017/2018 planning period. Of the requested outages, 73.4 percent were planned for five days or shorter and 8.5 percent were planned for longer than 30 days. Of the requested outages, 43.7 percent were late according to the rules in PJM's Manual 3.

Recommendations

The MMU recommends improvements to the planning process.

- 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 rules be implemented to permit competition to provide financing for transmission projects. This competition could

7 See "2017 RTEP Process Scope and Input Assumptions White Paper," P 25. <http://www.pjm.com/-/media/library/reports-notices/2017-rtep/20170731-rtep-input-assumptions-and-scope-whitepaper.ashx?la=en>.

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

9 PJM. "Manual 03: Transmission Operations," Rev. 52 (Dec. 22, 2017) Section 4.

reduce the cost of capital for transmission projects and significantly reduce total costs to customers. (Priority: Low. First reported 2013. Status: Not adopted.)

- The MMU recommends that rules be implemented to require that project cost caps on new transmission projects be part of the evaluation of competing projects. (Priority: Low. First reported 2015. Status: Not adopted.)
- The MMU recommends that barriers to entry be addressed in a timely manner in order to help ensure that the capacity market will result in the entry of new capacity to meet the needs of PJM market participants and reflect the uncertainty and resultant risks in the cost of new entry used to establish the capacity market demand curve in RPM. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends that the question of whether Capacity Injection Rights (CIRs) should persist after the retirement of a unit be addressed. Even if the treatment of CIRs remains unchanged, the rules need to ensure that incumbents cannot exploit control of CIRs to block or postpone entry of competitors.[10] (Priority: Low. First reported 2013. Status: Not 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.)
- 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 merchant transmission providers in the RTEP. (Priority: Medium. First reported 2014. Status: Not adopted.)
- The MMU recommends that PJM enhance the transparency and queue management process for merchant 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 merchant transmission. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends consideration of changing the minimum distribution factor in the allocation from 0.01 to 0.00 and adding a threshold minimum usage impact on the line. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM reevaluate all transmission outage tickets as on time or late as if they were new requests when an outage is rescheduled and apply the standard rules for late submissions to any such outages. (Priority: Low. First reported 2014. Status: Not adopted.)
- The MMU recommends that PJM draft a clear definition of the congestion analysis required for transmission outage requests to include in Manual 3 after appropriate review. (Priority: Low. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM modify the rules to reduce or eliminate the approval of late outage requests submitted or rescheduled after the FTR auction bidding opening date. (Priority: Low. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM not permit transmission owners to divide long duration outages into smaller segments to avoid complying with the requirements for long duration outages. (Priority: Low. First reported 2015. Status: Not adopted.)
- The MMU recommends improvements in queue management including that PJM establish a review process to ensure that projects are removed from the queue if they are not viable, as well as a process to allow commercially viable projects to advance in the queue ahead of projects which have failed to make progress, subject to rules to prevent gaming. (Priority: Medium. First reported 2013. Status: Partially adopted.)
- The MMU recommends an analysis of the study phase of PJM's transmission planning to reduce the need for postponements of study results, to

10 See "Comments of the Independent Market Monitor for PJM," Docket No. ER12-1177-000 <http://www.monitoringanalytics.com/reports/Reports/2012/IMM_Comments_ER12-1177-000_20120312.pdf>.

decrease study completion times, and to improve the likelihood that a project at a given phase in the study process will successfully go into service. (Priority: Medium. First reported 2014. Status: Partially adopted.)

- The MMU recommends that PJM limit the scope of supplemental projects that can obtain exceptions to the Order No. 1000 process, to ensure maximum competition. (Priority: Medium. New recommendation. Status: Not adopted.)

Conclusion

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

The 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.

Managing the generation queues is a highly complex process. The PJM queue evaluation process has been substantially improved in recent years and it is more efficient and effective as a result. The PJM queue evaluation process should continue to be improved to help ensure that barriers to competition for new generation investments are not created. Issues that need to be addressed include the ownership rights to CIRs, whether transmission owners should perform interconnection studies, and improvements in queue management to ensure that projects are removed from the queue if they are not viable, as well as a process to allow commercially viable projects to advance in the queue ahead of projects which have failed to make progress.

The 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 merchant transmission providers. PJM should enhance the transparency and queue management process for merchant 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 merchant 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. Because PJM now has the responsibility for planning the development of the grid under its RTEP process, property bought to facilitate future expansion should be a part of the RTEP process and be made available to all providers on equal terms.

There are currently no market incentives for transmission owners to submit and complete transmission outages in a timely and efficient manner. Requiring transmission owners to pay does not create an effective incentive when those payments are passed through to transmission customers. The process for the submission of planned transmission outages needs to be carefully reviewed and redesigned to limit the ability of transmission owners to submit transmission outages that are late for FTR auction bid submission dates and are late for the Day-Ahead Energy Market. The submission of late transmission outages can inappropriately affect market outcomes when market participants do not have the ability to modify market bids and offers.

Planned Generation and Retirements

Planned Generation Additions

Expected net revenues provide incentives to build new generation to serve PJM markets. The amount of planned new generation in PJM reflects investors' perception of the incentives provided by the combination of revenues from the PJM energy, capacity and ancillary service markets. On December 31, 2017, 99,452.5 MW of capacity were in generation request queues for construction through 2024, compared to an installed capacity of 201,496.5 MW as of December 31, 2017. Although it is clear that not all generation in the queues will be built, PJM has added capacity.[11] In 2017, 5,124.5 MW of nameplate capacity went into service in PJM.

PJM Generation Queues

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. The duration of the queue period has varied. Queues A and B were open for a year. Queues C through T were open for six months. Starting in February 2008, Queues U through Y1 were open for three months. Starting in May 2012, the duration of the queue period was reset to six months, starting with Queue Y2. Queue AD1 closed on September 30, 2017. Queue AD2 began on October 1, 2017.

All projects that have been entered in a queue 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. Withdrawn projects are removed from the queue and listed separately. 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.[12]

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.[13]

Table 12-1 shows MW in queues by expected completion date and MW changes in the queues between December 31, 2016, and December 31, 2017, for ongoing projects, i.e. projects with the status active, under construction or suspended.[14] Projects that are already in service are not included here. The total MW in queues increased by 17,516.2 MW, or 21.4 percent, from 81,936.3 MW at the end of 2016 to 99,452.5 MW on December 31, 2017.

Table 12-1 Queue comparison by expected completion year (MW): December 31, 2016 to December 31, 2017[15]

			Year Change	
Year	As of 12/31/2016	As of 12/31/2017	MW	Percent
2016	21,064.0	0.0	(21,064.0)	(100.0%)
2017	12,957.0	10,827.9	(2,129.1)	(16.4%)
2018	14,859.6	22,367.2	7,507.6	50.5%
2019	18,416.5	26,679.1	8,262.6	44.9%
2020	10,869.3	24,903.5	14,034.2	129.1%
2021	1,925.9	10,983.9	9,058.0	470.3%
2022	250.0	3,690.9	3,440.9	1,376.4%
2023	0.0	0.0	0.0	0.0%
2024	1,594.0	0.0	(1,594.0)	(100.0%)
Total	81,936.3	99,452.5	17,516.2	21.4%

Table 12-2 shows the project status changes in more detail and how scheduled queue capacity has changed between December 31, 2016, and December 31, 2017. For example, 28,415.2 MW entered the queue between January 1, 2017 and December 31, 2017. Of those 28,415.2 MW, 9,657.3 MW have been withdrawn. Of the total 63,727.4 MW marked as active at the beginning of 2017, 6,941.0 MW were withdrawn, 2,810.1 MW were suspended, 1,705.6 MW started construction, and 398.3 MW went into service by December 31, 2017. The Under Construction column shows that 791.4 MW came out of suspension and 1,705.6 MW began construction in 2017, in addition to the 16,489.3 MW of capacity that maintained the status under construction from December 31, 2016 through December 31, 2017.

11 See Monitoring Analytics, "New Generation in the PJM Capacity Market: MW and Funding Sources for Delivery Years 2007/2008 through 2018/2019," <http://www.monitoringanalytics.com/reports/Reports/2016/New_Generation_in_the_PJM_Capacity_Market_20160504.pdf>.

12 See "PJM Manual 14C Generation and Transmission Interconnection Process," Rev. 12 (June 22, 2017) Section 3.7

13 PJM does not track the duration of suspensions or PJM termination of projects.

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

15 Wind and solar capacity in Table 12-1 through Table 12-4 have not been adjusted to reflect derating.

Table 12-2 Change in project status (MW): December 31, 2016 to December 31, 2017

		Status at 12/31/2017				
Status at 12/31/2016	Total at 12/31/2016	Active	Suspended	Under Construction	In Service	Withdrawn
(Entered during 2017)		18,757.8	0.0	0.0	0.0	9,657.3
Active	63,727.4	51,872.4	2,810.1	1,705.6	398.3	6,941.0
Suspended	5,790.0	371.0	3,645.3	791.4	0.0	982.3
Under Construction	24,012.9	108.9	2,900.7	16,489.3	4,228.1	285.9
In Service	46,934.1	0.0	0.0	0.0	46,934.1	0.0
Withdrawn	305,900.6	0.0	0.0	0.0	0.0	305,900.6
Total	446,365.0	71,110.1	9,356.1	18,986.3	51,560.5	323,767.2

Table 12-3 shows the amount of capacity active, in service, under construction, suspended, or withdrawn for each queue since the beginning of the RTEP process and the total amount of capacity that had been included in each queue. All items in queues A-M are either in service or have been withdrawn. As of December 31, 2017, there are 99,452.5 MW of capacity in queues that are not yet in service, of which 9.4 percent are suspended, 19.1 percent are under construction and 71.5 percent have not begun construction.

Table 12-3 Capacity in PJM queues (MW): December 31, 2017[16]

Queue	Active	In Service	Under Construction	Suspended	Withdrawn	Total
A Expired 31-Jan-98	0.0	8,631.0	0.0	0.0	17,252.0	25,883.0
B Expired 31-Jan-99	0.0	4,645.5	0.0	0.0	15,656.7	20,302.2
C Expired 31-Jul-99	0.0	531.0	0.0	0.0	3,474.8	4,005.8
D Expired 31-Jan-00	0.0	850.6	0.0	0.0	7,369.0	8,219.6
E Expired 31-Jul-00	0.0	795.2	0.0	0.0	8,033.8	8,829.0
F Expired 31-Jan-01	0.0	52.0	0.0	0.0	3,092.5	3,144.5
G Expired 31-Jul-01	0.0	1,189.6	0.0	0.0	17,980.8	19,170.4
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	3,738.3	3,841.3
J Expired 31-Jan-03	0.0	42.0	0.0	0.0	846.0	888.0
K Expired 31-Jul-03	0.0	99.0	0.0	0.0	485.3	584.3
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	38.0	0.0	8,090.2	10,527.0
O Expired 31-Jul-05	0.0	1,668.2	437.0	0.0	5,466.8	7,572.0
P Expired 31-Jan-06	0.0	3,037.3	253.0	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	1,986.4	60.0	1,240.0	19,468.9	22,755.3
S Expired 31-Jul-07	0.0	3,669.5	0.0	70.0	12,396.5	16,136.0
T Expired 31-Jan-08	0.0	3,014.0	1,208.0	300.0	23,013.3	27,535.3
U Expired 31-Jan-09	200.0	837.3	649.9	820.0	30,829.6	33,336.8
V Expired 31-Jan-10	390.0	2,748.6	36.1	761.0	12,877.6	16,813.3
W Expired 31-Jan-11	663.0	2,175.7	837.1	618.8	19,759.2	24,053.7
X Expired 31-Jan-12	1,687.5	4,601.2	3,258.9	1,979.0	18,816.3	30,343.0
Y Expired 30-Apr-13	470.5	2,433.1	3,036.6	267.2	19,532.2	25,739.5
Z Expired 30-Apr-14	997.0	714.4	5,543.4	114.3	6,931.5	14,300.7
AA1 Expired 31-Oct-14	3,542.3	199.8	2,215.0	396.1	5,645.5	11,998.7
AA2 Expired 30-Apr-15	4,814.2	320.9	676.5	2,474.9	7,779.8	16,066.3
AB1 Expired 31-Oct-15	11,863.1	64.0	715.9	170.7	7,629.9	20,443.6
AB2 Expired 31-Mar-16	10,854.9	122.1	20.9	103.6	4,163.0	15,264.5
AC1 Through 30-Sep-16	16,538.4	18.7	0.0	40.5	3,490.8	20,088.5
AC2 Through 30-Apr-17	6,612.7	0.0	0.0	0.0	5,772.0	12,384.7
AD1 Through 30-Sep-17	10,482.8	0.0	0.0	0.0	1,225.0	11,707.8
AD2 Through 30-Apr-18	1,993.7	0.0	0.0	0.0	82.4	2,076.1
Total	71,110.1	51,560.5	18,986.3	9,356.1	323,767.2	474,780.1

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

Distribution of Units in the Queues

Table 12-4 shows the projects under construction, suspended, or active, by unit type, and control zone.[17] As of December 31, 2017, 99,452.5 MW of capacity were in generation request queues for construction through 2024, compared to 93,533.3 MW at December 31, 2016.[18] Table 12-4 also shows the planned retirements for each zone.

Table 12-4 Queue capacity by LDA, control zone and fuel (MW): December 31, 2017[19]

LDA	Zone	Biomass	CC	CT	Coal	Diesel	Fuel Cell	Hydro	Nuclear	Solar	Storage	Wind	Other	Total Queue Capacity	Planned Retirements
EMAAC	AECO	0.0	1,674.6	462.0	0.0	0.0	1.9	0.0	0.0	24.2	20.0	25.0	0.0	2,207.7	303.0
	DPL	4.0	1,111.0	0.0	0.0	25.2	0.0	0.0	0.0	1,386.7	21.0	649.6	0.0	3,197.5	0.0
	JCPL	0.0	1,842.1	0.0	0.0	0.0	0.4	0.0	0.0	196.7	85.0	0.0	0.0	2,124.2	614.5
	PECO	0.0	1,309.0	0.0	0.0	4.5	0.0	0.0	94.0	18.0	0.0	0.0	0.0	1,425.5	50.8
	PSEG	0.0	3,241.5	2.0	24.0	0.0	3.4	0.0	0.0	69.8	0.0	0.0	0.0	3,340.7	611.0
	RECO	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	EMAAC Total	4.0	9,178.2	464.0	24.0	29.7	5.7	0.0	94.0	1,695.4	126.0	674.6	0.0	12,295.6	1,579.3
SWMAAC	BGE	0.0	0.0	0.0	0.0	1.3	0.0	0.4	30.3	22.0	0.1	0.0	0.0	54.1	534.0
	Pepco	0.0	1,932.6	0.0	0.0	0.0	0.0	0.0	0.0	65.3	0.0	0.0	0.0	1,997.9	0.0
	SWMAAC Total	0.0	1,932.6	0.0	0.0	1.3	0.0	0.4	30.3	87.3	0.1	0.0	0.0	2,051.9	534.0
WMAAC	Met-Ed	0.0	485.0	0.0	0.0	0.0	0.0	0.0	0.0	158.0	0.0	0.0	30.0	673.0	805.0
	PENELEC	0.0	1,333.0	756.1	0.0	126.4	0.0	0.0	0.0	63.5	0.0	458.8	590.0	3,327.8	110.0
	PPL	16.0	5,449.0	19.9	0.0	19.9	0.0	0.0	0.0	30.0	120.0	441.1	0.0	6,095.9	8.2
	WMAAC Total	16.0	7,267.0	776.0	0.0	146.3	0.0	0.0	0.0	251.5	120.0	899.8	620.0	10,096.6	923.2
Non-MAAC	AEP	0.0	9,449.0	413.0	119.0	15.2	0.0	34.0	28.0	4,963.5	40.0	8,283.6	30.0	23,375.3	0.0
	APS	0.0	5,805.1	100.0	10.0	119.6	0.0	15.0	0.0	673.3	37.8	1,170.7	0.0	7,931.5	27.4
	ATSI	0.0	5,191.0	70.0	0.0	0.0	0.0	0.0	0.0	646.0	0.0	1,316.1	0.0	7,223.0	776.0
	ComEd	0.0	8,270.2	1,127.0	0.0	18.8	0.0	22.7	0.0	1,025.5	86.5	4,599.7	64.0	15,214.4	4.0
	DAY	0.0	1,150.0	0.0	12.0	0.0	0.0	0.0	0.0	762.9	39.9	300.0	0.0	2,264.8	2,364.0
	DEOK	0.0	513.0	0.0	20.0	0.0	0.0	0.0	0.0	300.0	19.8	0.0	0.0	852.8	0.0
	DLCO	0.0	205.0	0.0	0.0	0.0	0.0	0.0	0.0	20.0	20.0	0.0	0.0	245.0	0.0
	Dominion	62.5	6,849.7	155.0	14.0	8.0	0.0	5.5	0.0	9,514.5	34.0	1,043.5	0.0	17,686.7	728.0
	EKPC	0.0	0.0	75.0	0.0	0.0	0.0	0.0	0.0	100.0	0.0	0.0	0.0	175.0	0.0
	RMU	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	40.0	0.0	0.0	0.0	40.0	0.0
	Non-MAAC Total	62.5	37,433.0	1,940.0	175.0	161.6	0.0	77.2	28.0	18,045.6	278.0	16,713.5	94.0	75,008.4	3,899.4
Total in PJM	Total	82.5	55,810.8	3,180.0	199.0	338.9	5.7	77.6	152.3	20,079.8	524.1	18,287.9	714.0	99,452.5	6,935.9

A significant shift in the distribution of unit types within the PJM footprint continues to develop as natural gas fired units enter the queue and coal fired steam units retire. As of December 31, 2017, there were 15,162.3 MW of gas fired capacity under construction in PJM. As of December 31, 2017, there were only 108.0 MW of coal fired steam capacity under construction in PJM. With respect to retirements, 4,620 MW of coal fired steam capacity and 661.8 MW of natural gas capacity are slated for deactivation between December 31, 2017, and December 31, 2020. The replacement of coal fired steam units by natural gas units could significantly affect future congestion, the role of firm and interruptible gas supply, and natural gas supply infrastructure.

Planned Retirements

As shown in Table 12-5, 32,699.3 MW have been, or are planned to be, retired between 2011 and 2020.[20] Of that, 6,935.9 MW are planned to retire after December 31, 2017. In 2017, 2,126.8 MW were retired. Of the 6,935.9 MW pending retirement, 4,620.0 MW are coal units. The coal unit retirements were a result of low gas prices, low capacity prices and the investments required for compliance with the EPA's Mercury and Air Toxics Standards (MATS) for some units.

17 Unit types designated as reciprocating engines are classified as diesel.

18 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 derates wind resources to 13 percent of nameplate capacity until there is operational data to support a different conclusion. PJM derates solar resources to 38 percent of nameplate capacity. Based on the derating of 15,910.5 MW of wind resources and 12,449.5 MW of solar resources, the 99,452.5 MW currently active in the queue would be reduced to 71,092.5 MW.

19 This data includes only projects with a status of active, under-construction, or suspended.

20 See PJM "Generator Deactivation Summary Sheets," at <http://www.pjm.com/planning/generation-deactivation/gd-summaries.aspx> (December 29, 2017).

Table 12-5 Summary of PJM unit retirements by fuel (MW): 2011 through 2020

	Battery	Coal	Diesel	Heavy Oil	Hydro	Kerosene	Landfill Gas	Light Oil	Natural Gas	Nuclear	Waste Coal	Wind	Wood Waste	Total
Retirements 2011	0.0	543.0	0.0	0.0	0.0	0.0	0.0	131.0	522.5	0.0	0.0	0.0	0.0	1,196.5
Retirements 2012	0.0	5,907.9	0.0	0.0	0.0	0.0	0.0	788.0	250.0	0.0	0.0	0.0	16.0	6,961.9
Retirements 2013	0.0	2,558.9	2.9	166.0	0.0	0.0	7.0	3.0	82.0	0.0	31.0	0.0	8.0	2,858.8
Retirements 2014	0.0	2,239.0	50.0	0.0	0.0	184.0	15.3	188.0	294.0	0.0	0.0	0.0	0.0	2,970.3
Retirements 2015	0.0	7,064.8	0.0	0.0	0.0	644.2	2.0	222.3	1,319.0	0.0	0.0	10.4	0.0	9,262.7
Retirements 2016	0.0	243.0	51.0	0.0	0.5	0.0	9.9	22.0	74.0	0.0	0.0	0.0	0.0	400.4
Retirements 2017	40.0	2,038.0	0.0	0.0	0.0	0.0	0.8	0.0	34.0	0.0	0.0	0.0	0.0	2,112.8
Planned Retirements (2018 and later)	27.4	4,620.0	2.4	148.0	0.0	0.0	4.0	52.8	661.8	1,419.5	0.0	0.0	0.0	6,935.9
Total	67.4	25,214.6	106.3	314.0	0.5	828.2	39.0	1,407.1	3,237.3	1,419.5	31.0	10.4	24.0	32,699.3

A map of the retirements between 2011 and 2020 is shown in Figure 12-1 with a mapping to unit names identified in Table 12-6.

Figure 12-1 Map of PJM unit retirements: 2011 through 2020

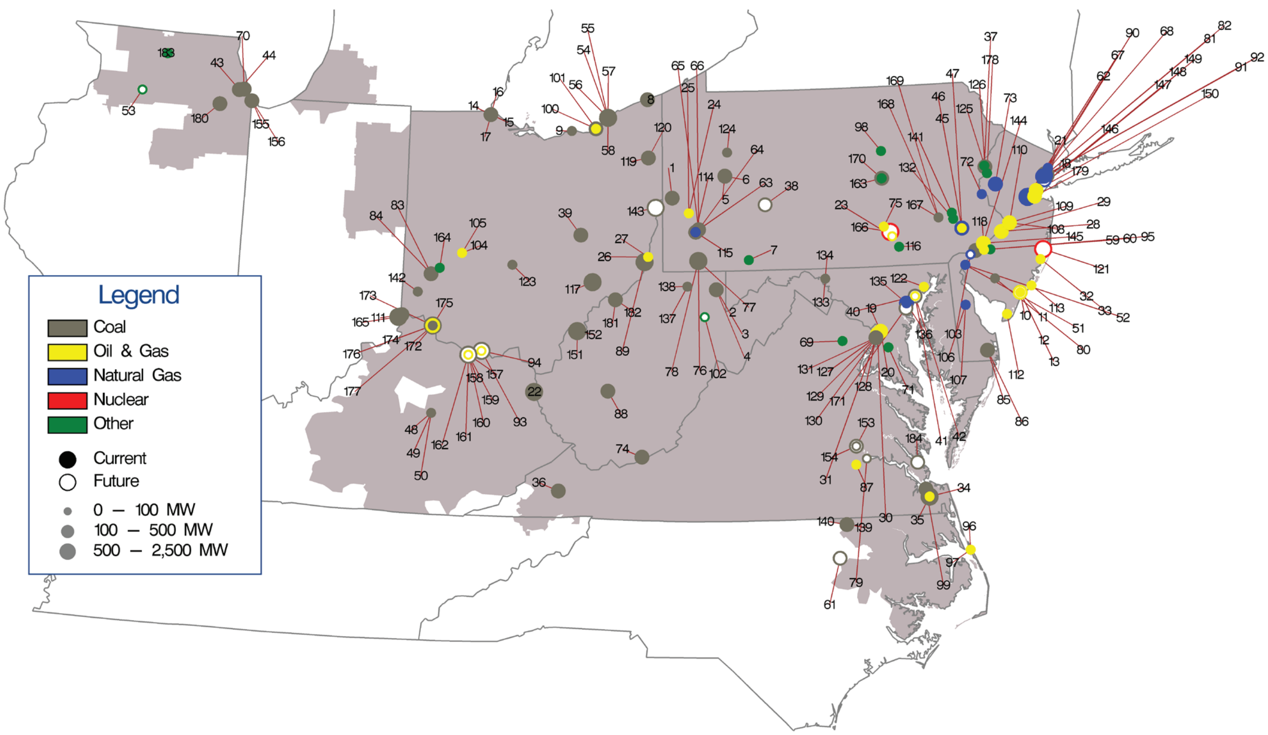


Table 12-6 Unit identification for map of PJM unit retirements: 2011 through 2020

ID	Unit	ID	Unit	ID	Unit	ID	Unit	ID	Unit	ID	Unit
1	AES Beaver Valley	36	Clinch River 3	71	GUDE Landfill	106	McKee 1	141	Rolling Hills Landfill Generator	176	Walter C Beckjord 5-6
2	Albright 1	37	Columbia Dam Hydro	72	Gilbert 1-4	107	McKee 2	142	SMART Paper	177	Walter C Beckjord GT 1-4
3	Albright 2	38	Colver Power Project	73	Glen Gardner 1-8	108	Mercer 1	143	Sammis 1-4	178	Warren County Landfill
4	Albright 3	39	Conesville 3	74	Glen Lyn 5-6	109	Mercer 2	144	Schuylkill 1	178	Werner 1-4
5	Armstrong 1	40	Crane 1	75	Harrisburg 4 CT	110	Mercer 3	145	Schuylkill Diesel	180	Will County 3
6	Armstrong 2	41	Crane 2	76	Hatfield's Ferry 1	111	Miami Fort 6	146	Sewaren 1	151	Willow Island 1
7	Arnold (Green Mtn. Wind Farm	42	Crane GT1	77	Hatfield's Ferry 2	112	Middle 1-3	147	Sewaren 2	152	Willow Island 2
8	Ashtabula 5	43	Crawford 7	78	Hatfield's Ferry 3	113	Missouri Ave B,C,D	148	Sewaren 3	153	Winnebago Landfill
9	Avon Lake 7	44	Crawford 8	79	Hopewell James River Cogeneration	114	Mitchell 2	149	Sewaren 4	154	Yorktown 1-2
10	BL England 1	45	Cromby 1	80	Howard Down 10	115	Mitchell 3	150	Sewaren 6		
11	BL England 2	46	Cromby 2	81	Hudson 1	116	Modern Power Landfill NUG	151	Sporn 1-4		
12	BL England 3	47	Cromby D	82	Hudson 2	117	Muskingum River 1-5	152	Sporn 5		
13	BL England Diesel Units 1-4	48	Dale 1-2	83	Hutchings 1-3, 5-6	118	National Park 1	153	Spruance NUG1 (Rich 1-2)		
14	Bay Shore 1	49	Dale 3	84	Hutchings 4	119	Niles 1	154	Spruance NUG2 (Rich 3-4)		
15	Bay Shore 2	50	Dale 4	85	Indian River 1	120	Niles 2	155	State Line 3		
16	Bay Shore 3	51	Deepwater 1	86	Indian River 3	121	Oyster Creek	156	State Line 4		
17	Bay Shore 4	52	Deepwater 6	87	Ingenco Petersburg	122	Perryman 2	157	Stuart 1		
18	Bayonne Cogen Plant (CC)	53	Dixon Lee Landfill Generator	88	Kanawha River 1-2	123	Picway 5	158	Stuart 2		
19	Benning 15	54	Eastlake 1	89	Kanmer 1-3	124	Piney Creek NUG	159	Stuart 3		
20	Benning 16	55	Eastlake 2	90	Kearny 10	125	Portland 1	160	Stuart 4		
21	Bergen 3	56	Eastlake 3	91	Kearny 11	126	Portland 2	161	Stuart Diesels 1-4		
22	Big Sandy 2	57	Eastlake 4	92	Kearny 9	127	Potomac River 1	162	Stuart Diesels 1-4		
23	Brunner Island Diesels	58	Eastlake 5	93	Killen 2	128	Potomac River 2	163	Sunbury 1-4		
24	Brunot Island 1B	59	Eddystone 1	94	Killen CT	129	Potomac River 3	164	Tait Battery		
25	Brunot Island 1C	60	Eddystone 2	95	Kinsley Landfill	130	Potomac River 4	165	Tanners Creek 1-4		
26	Burger 3	61	Edgecomb NUG (Rocky 1-2)	96	Kitty Hawk GT 1	131	Potomac River 5	166	Three Mile Island Unit 1		
27	Burger EMD	62	Edison 1-3	97	Kitty Hawk GT 2	132	Pottstown LF (Moser)	167	Titus 1		
28	Burlington 8,11	63	Elrama 1	98	Koppers Co. IPP	133	R Paul Smith 3	168	Titus 2		
29	Burlington 9	64	Elrama 2	99	Lake Kingman	134	R Paul Smith 4	169	Titus 3		
30	Buzzard Point East Banks 1,2,4-8	65	Elrama 3	100	Lake Shore 18	135	Riverside 4	170	Viking Energy NUG		
31	Buzzard Point West Banks 1-9	66	Elrama 4	101	Lake Shore EMD	136	Riverside 6	171	Wagner 2		
32	Cedar 1	67	Essex 10-11	102	Laurel Mountain Battery	137	Riversville 5	172	Walter C Beckjord 1		
33	Cedar 2	68	Essex 12	103	MH50 Markus Hook Co-gen	138	Riversville 6	173	Walter C Beckjord 2		
34	Chesapeake 1-4	69	Fauquier County Landfill	104	Mad River CTs A	139	Roanoke Valley 1	174	Walter C Beckjord 3		
35	Chesapeake 7-10	70	Fisk Street 19	105	Mad River CTs B	140	Roanoke Valley 2	175	Walter C Beckjord 4		

The list of pending retirements is shown in Table 12-7.

Table 12-7 Planned retirement of PJM units: December 31, 2017[21]

Unit	Zone	ICAP (MW)	Fuel	Unit Type	Projected Deactivation Date
BL England 3	AECO	148.0	Heavy Oil	Steam	24-Jan-18
Brunner Island Diesels	PPL	8.2	Light Oil	Diesel	25-Feb-18
Dixon Lee Landfill Generator	ComEd	4.0	Landfill Gas	Diesel	06-Mar-18
Yorktown 1-2	Dominion	323.0	Coal	Steam	13-Mar-18
Laurel Mountain Battery	APS	27.4	Battery	Battery	16-Mar-18
Hopewell James River Cogeneration	Dominion	89.0	Coal	Steam	31-May-18
Crane 1	BGE	190.0	Coal	Steam	01-Jun-18
Crane 2	BGE	195.0	Coal	Steam	01-Jun-18
Killen 2	DAY	600.0	Coal	Steam	01-Jun-18
Stuart 2	DAY	577.0	Coal	Steam	01-Jun-18
Stuart 3	DAY	577.0	Coal	Steam	01-Jun-18
Stuart 4	DAY	577.0	Coal	Steam	01-Jun-18
Stuart Diesels 1-4	DAY	2.4	Diesel	Diesel	01-Jun-18
Killen CT	DAY	24.0	Light Oil	CT	01-Jun-18
Stuart Diesels 1-4	DAY	6.6	Light Oil	Diesel	01-Jun-18
Sewaren 1	PSEG	104.0	Natural Gas	Steam	01-Jun-18
Sewaren 2	PSEG	118.0	Natural Gas	Steam	01-Jun-18
Sewaren 3	PSEG	107.0	Natural Gas	Steam	01-Jun-18
Sewaren 4	PSEG	124.0	Natural Gas	Steam	01-Jun-18
Bayonne Cogen Plant (CC)	PSEG	158.0	Natural Gas	Steam	01-Nov-18
Spruance NUG1 (aka Spruance 1 Rich 1-2)	Dominion	115.5	Coal	Steam	12-Jan-19
Spruance NUG2 (aka Spruance 2 Rich 3-4)	Dominion	85.0	Coal	Steam	12-Jan-19
BL England 2	AECO	155.0	Coal	Steam	30-Apr-19
MH50 Markus Hook Co-gen	PECO	50.8	Natural Gas	Steam	13-May-19
Three Mile Island Unit 1 Nuclear Generating Station	Met-Ed	805.0	Nuclear	Nuclear	30-Sep-19
Crane GT1	BGE	14.0	Light Oil	CT	31-Oct-19
Oyster Creek Nuclear Generating Station	JCPL	614.5	Nuclear	Nuclear	31-Dec-19
Sammis 1-4	ATSI	640.0	Coal	Steam	31-May-20
Wagner 2	BGE	135.0	Coal	Steam	01-Jun-20
Colver Power Project	PENELEC	110.0	Coal	Steam	01-Sep-20
Bay Shore 1	ATSI	136.0	Coal	Steam	01-Oct-20
Edgecomb NUG (aka Edgecomb Rocky 1-2)	Dominion	115.5	Coal	Steam	31-Oct-20
Total		6,935.9			

Table 12-8 shows the capacity, average size, and average age of units retiring in PJM, from 2011 through 2020, while Table 12-9 shows these retirements by state. The majority, 77.1 percent, of all MW retiring during this period are coal fired steam units. These coal fired steam units have an average age of 54.2 years and an average size of 172.7 MW. Over half of the retiring coal fired steam units, 55.0 percent, are located in either Ohio or Pennsylvania. Retirements have generally consisted of smaller subcritical coal fired steam units and those without adequate environmental controls to remain viable beyond 2017.

21 Units designated as external installed capacity have been removed.

Table 12-8 Retirements by fuel type: 2011 through 2020

Fuel	Number of Units	Avg. Size (MW)	Avg. Age at Retirement (Years)	Total MW	Percent
Battery	2	33.7	6.5	67.4	0.2%
Coal	146	172.7	54.2	25,214.6	77.1%
Diesel	5	21.3	39.8	106.3	0.3%
Heavy Oil	2	157.0	48.9	314.0	1.0%
Hydro	1	0.5	113.8	0.5	0.0%
Kerosene	20	41.4	45.5	828.2	2.5%
Landfill Gas	10	3.9	13.1	39.0	0.1%
Light Oil	32	44.0	43.6	1,407.1	4.3%
Natural Gas	55	58.9	47.3	3,237.3	9.9%
Nuclear	2	709.8	47.8	1,419.5	4.3%
Waste Coal	1	31.0	20.3	31.0	0.1%
Wind	1	10.4	15.6	10.4	0.0%
Wood Waste	2	12.0	23.2	24.0	0.1%
Total	279	117.2	48.8	32,699.3	100.0%

Table 12-9 Retirements (MW) by fuel type and state: 2011 through 2020

State	Battery	Coal	Diesel	Heavy Oil	Hydro	Kerosene	Landfill Gas	Light Oil	Natural Gas	Nuclear	Waste Coal	Wind	Wood Waste	Total
DC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	788.0	0.0	0.0	0.0	0.0	0.0	788.0
DE	0.0	254.0	0.0	0.0	0.0	0.0	0.0	0.0	34.0	0.0	0.0	0.0	0.0	288.0
IL	0.0	1,624.0	0.0	0.0	0.0	0.0	10.4	0.0	0.0	0.0	0.0	0.0	0.0	1,634.4
IN	0.0	982.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	982.0
KY	0.0	995.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	995.0
MD	0.0	635.0	51.0	0.0	0.0	0.0	0.8	14.0	189.0	0.0	0.0	0.0	0.0	889.8
NC	0.0	324.5	0.0	0.0	0.0	0.0	0.0	31.0	0.0	0.0	0.0	0.0	0.0	355.5
NJ	0.0	1,543.0	0.0	148.0	0.5	828.2	9.8	220.0	2,680.5	614.5	0.0	0.0	0.0	6,044.5
OH	40.0	9,248.6	52.4	0.0	0.0	0.0	0.0	228.9	0.0	0.0	0.0	0.0	0.0	9,569.9
PA	0.0	4,627.0	0.0	166.0	0.0	0.0	16.0	57.9	333.8	805.0	31.0	10.4	24.0	6,071.1
VA	0.0	2,340.5	2.9	0.0	0.0	0.0	2.0	67.3	0.0	0.0	0.0	0.0	0.0	2,412.7
WV	27.4	2,641.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,668.4
Total	67.4	25,214.6	106.3	314.0	0.5	828.2	39.0	1,407.1	3,237.3	1,419.5	31.0	10.4	24.0	32,699.3

Generation Deactivations in 2017

Table 12-10 shows the units that were deactivated in 2017.

Table 12-10 Unit deactivations in 2017

Company	Unit Name	ICAP (MW)	Primary Fuel	Zone Name	Average Age (Years)	Retirement Date
Dominion Resources, Inc.	Roanoke Valley 1	165.0	Coal	Dominion	22.8	01-Mar-17
Dominion Resources, Inc.	Roanoke Valley 2	44.0	Coal	Dominion	21.8	01-Mar-17
City of Dover	McKee 1	17.0	Natural Gas	DPL	55.4	31-May-17
City of Dover	McKee 2	17.0	Natural Gas	DPL	55.3	31-May-17
Public Service Enterprise Group Incorporated	Hudson 2	620.0	Coal	PSEG	48.5	01-Jun-17
Public Service Enterprise Group Incorporated	Mercer 1	316.0	Coal	PSEG	56.5	01-Jun-17
Public Service Enterprise Group Incorporated	Mercer 2	316.0	Coal	PSEG	56.0	01-Jun-17
Northeast Maryland Waste Disposal Authority	GUDE Landfill	0.8	Landfill Gas	Pepco	8.8	24-Aug-17
Dynegy Inc.	Stuart 1	225.0	Coal	DAY	46.5	30-Sep-17
The AES Corporation	Stuart 1	202.0	Coal	DAY	46.5	30-Sep-17
American Electric Power Company, Inc.	Stuart 1	150.0	Coal	DAY	46.5	30-Sep-17
The AES Corporation	Tait Battery	40.0	Battery	DAY	4.4	13-Dec-17
Total		2,112.8				

Existing Generation Mix

As of December 31, 2017, PJM had an installed capacity of 201,496.5 MW (Table 12-11). This measure 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.

Table 12-11 Existing PJM capacity: December 31, 2017 (By zone and unit type (MW))[22]

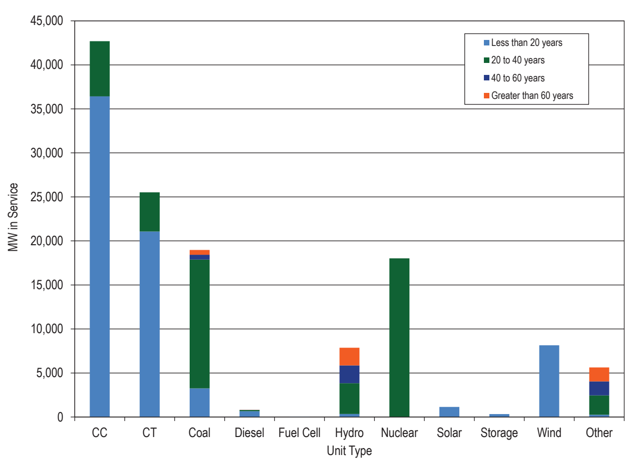
ZONE	CC	CT	Coal	Diesel	Fuel Cell	Hydro	Nuclear	Solar	Storage	Wind	Other	Total
AECO	901.9	570.7	613.9	14.6	1.6	0.0	0.0	59.4	0.0	7.5	202.0	2,371.5
AEP	6,840.0	3,682.2	18,159.8	80.3	0.0	1,071.9	2,071.0	14.7	6.0	2,474.0	738.0	35,137.9
APS	1,749.0	1,560.9	5,409.0	47.9	0.0	129.2	0.0	46.1	78.9	1,191.5	0.0	10,212.5
ATSI	1,570.5	1,618.3	5,394.0	63.7	0.0	0.0	2,134.0	0.0	0.0	0.0	325.0	11,105.5
BGE	0.0	936.6	2,098.0	22.4	0.0	0.4	1,716.0	1.1	0.0	0.0	823.5	5,598.0
ComEd	3,146.1	7,244.0	3,840.1	109.1	0.0	0.0	10,473.5	9.0	127.6	3,081.9	1,326.0	29,357.3
DAY	0.0	1,368.5	2,331.0	47.5	0.0	0.0	0.0	1.1	40.0	0.0	0.0	3,788.1
DEOK	47.2	654.0	3,934.0	4.8	0.0	112.0	0.0	0.0	20.0	0.0	47.0	4,819.0
DLCO	244.0	15.0	660.0	0.0	0.0	6.3	1,777.0	0.0	0.0	0.0	0.0	2,702.3
Dominion	8,371.6	4,092.7	4,903.6	171.8	0.0	3,589.3	3,581.3	337.6	0.0	208.0	2,662.4	27,918.3
DPL	2,498.5	1,820.4	437.0	162.1	30.0	0.0	0.0	213.4	0.0	0.0	1,149.0	6,310.4
EKPC	0.0	774.0	1,687.0	0.0	0.0	70.0	0.0	0.0	0.0	0.0	0.0	2,531.0
JCPL	2,682.5	763.1	0.0	16.1	0.0	400.0	614.5	260.6	0.0	0.0	25.5	4,762.3
Met-Ed	2,630.8	401.7	35.0	33.4	0.0	19.5	805.0	0.0	0.0	0.0	165.0	4,090.4
PECO	3,209.0	834.0	3.3	2.9	0.0	3,284.0	4,546.8	3.0	1.0	0.0	975.8	12,859.8
PENELEC	850.0	407.5	6,056.5	150.0	0.0	590.8	0.0	0.0	28.4	958.8	743.0	9,785.0
Pepco	1,827.0	1,204.7	2,433.0	11.1	0.0	0.0	0.0	0.0	0.0	0.0	1,216.1	6,691.9
PPL	2,657.9	616.5	2,225.5	55.5	0.0	706.6	2,520.0	15.0	20.0	219.7	2,944.4	11,981.1
PSEG	4,000.3	1,134.0	0.0	11.1	0.0	5.0	3,493.0	182.7	4.0	0.0	644.1	9,474.2
RECO	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	43,226.3	29,698.8	60,220.7	1,004.3	31.6	9,985.0	33,732.1	1,143.7	325.9	8,141.4	13,986.8	201,496.5

Figure 12-2 and Table 12-12 show the age of PJM generators by unit type. Units older than 40 years comprise 80,669.0 MW, or 40.0 percent, of the total capacity of 201,496.5 MW.

Table 12-12 PJM capacity (MW) by age (years): December 31, 2017

Age (years)	CC	CT	Coal	Diesel	Fuel Cell	Hydro	Nuclear	Solar	Storage	Wind	Other	Total
Less than 20	36,420.8	21,072.4	3,250.0	666.8	31.6	339.7	0.0	1,143.7	325.9	8,141.4	247.9	71,640.1
20 to 40	6,273.5	4,441.8	14,632.8	117.9	0.0	3,493.2	18,018.9	0.0	0.0	0.0	2,209.3	49,187.4
40 to 60	532.0	4,184.6	41,790.4	215.6	0.0	4,133.0	15,713.2	0.0	0.0	0.0	9,946.1	76,514.9
Greater than 60	0.0	0.0	547.5	4.0	0.0	2,019.1	0.0	0.0	0.0	0.0	1,583.5	4,154.1
Total	43,226.3	29,698.8	60,220.7	1,004.3	31.6	9,985.0	33,732.1	1,143.7	325.9	8,141.4	13,986.8	201,496.5

Figure 12-2 PJM capacity (MW) by age (years): December 31, 2017



22 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. This table previously included external units.

Generation and Transmission Interconnection Planning Process

PJM made changes to the queue process in May 2012.[23] These changes included reducing the length of the queues, creating an alternate queue for some small projects, and adjustments to the rules regarding suspension rights and Capacity Interconnection Rights (CIR). PJM staff reported on June 11, 2015, that due to these and other process improvements, the study backlog has been significantly reduced. The Earlier Queue Submittal Task Force (EQSTF) was established in August 2015, to further address the issue.[24]

The Earlier Queue Submittal Task Force

In 2015 and 2016, participants of the Earlier Queue Submittal Task Force (EQSTF) drafted rule changes to the Interconnection Queue process meant to address high levels of deficient project applications being submitted to PJM for review.

To discourage incomplete interconnection project requests, the EQSTF proposed to only assign queue positions for project applications that had submitted all required project elements including site control. In addition, all project applications would be required to remedy any deficiencies by the end of the queue window in order to be considered in feasibility studies or be terminated and withdrawn. Queue positions had historically been assigned to project developers that paid the study deposit and submitted a project application by the appropriate submission deadline. Project applications with missing information were assigned queue numbers so long as these two criteria were met.

The EQSTF also proposed rule changes to interconnection study fee structures that would discourage the submission of speculative or incomplete queue projects. Under the old rules, deposits provided by developers for interconnection studies could not be charged until after a queue position was accepted. Under the new rules, these deposits would be available for charging before a queue position is assigned.

In addition, rather than socializing the study costs for deficient applications from project developers, the EQSTF proposed that these project costs be assigned directly to the developer that submitted the project. This would significantly increase the cost burden that developers would experience if a project is found to be deficient in the review process.

The EQSTF proposed to change the timing of queue windows and Feasibility Study dates to enable more generation projects to participate in the PJM Base Residual Auction. The EQSTF proposed shifting start dates for the queue windows back a month from May 1 to April 1 and Nov 1 to October 1. The EQSTF also proposed shifting feasibility study dates from Dec 1 to Nov 1 and June 1 to May 1.

Revisions to the OATT developed by the EQSTF were approved by the FERC effective October 31, 2016.[25] The revised OATT completed the EQSTF work assignment. The final meeting of the EQSTF was held on March 21, 2016.

On December 15, 2016, the Commission issued a notice of proposed rulemaking proposing additional queue reforms intended to improve certainty, promote more informed interconnection, and enhance interconnection processes.

Interconnection Queue Analysis

In the study phase of the interconnection planning process, a series of studies are performed to determine the feasibility, impact, and cost of projects in the queue. Table 12-13 is an overview of PJM's study process. System impact and facilities studies are often redone when a project is withdrawn in order to determine the impact on the projects remaining in the queue.

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

24 See Earlier Queue Submittal Task Force at <http://www.pjm.com/committees-and-groups/closed-groups/eqstf.aspx>.

25 See Letter Order, ER16-2518-000 (Oct. 7, 2016).

Table 12-13 PJM generation planning process

Process Step	Start on	Financial Obligation	Days for PJM to Complete	Days for Applicant to Decide Whether to Continue
Feasibility Study	Close of current queue	Cost of study (partially refundable deposit)	90	30
System Impact Study	Upon acceptance of the System Impact Study Agreement	Cost of study (partially refundable deposit)	120	30
Facilities Study	Upon acceptance of the Facilities Study Agreement	Cost of study (refundable deposit)	Varies	60
Schedule of Work	Upon acceptance of Interconnection Service Agreement (ISA)	Letter of credit for upgrade costs	Varies	37
Construction (only for new generation)	Upon acceptance of Interconnection Construction Service Agreement (ICSA)	None	Varies	NA

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.[26] 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 12-14 and Table 12-15.

Withdrawn Projects

Table 12-14 shows the milestone status when projects were withdrawn, for all withdrawn projects. Of the projects withdrawn, 52.9 percent were withdrawn before the system impact study was completed. Once an Interconnection Service Agreement (ISA) or a Wholesale Market Participation Agreement (WMPA) is executed, the financial obligation for any necessary transmission upgrades cannot be retracted.[27] [28] Withdrawing at or beyond this point is uncommon; only 257 projects, or 12.2 percent, of all projects withdrawn were withdrawn after reaching this milestone.

Table 12-14 Last milestone at time of withdrawal: 1997 through 2017

Milestone Completed	Projects Withdrawn	Percent	Average Days	Maximum Days
Never Started	283	13.4%	173	1,235
Feasibility Study	832	39.5%	344	3,238
System Impact Study	468	22.2%	604	3,174
Facilities Study	266	12.6%	1,340	4,210
Construction Service Agreement (CSA) or beyond	257	12.2%	1,538	4,249
Total	2,106	100.0%		

Table 12-15 and Table 12-16 show 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 1,007 days, or 2.8 years, between entering a queue and going into service. For withdrawn projects, there is an average time of 650 days, or 1.8 years, between entering a queue and withdrawing.

Table 12-15 Average project queue times (days): December 31, 2017

Status	Average (Days)	Standard Deviation	Minimum	Maximum
Active	945	528	99	3,745
In-Service	1,007	720	1	4,024
Suspended	2,059	1,150	696	4,773
Under Construction	1,928	1,049	473	4,977
Withdrawn	650	685	1	4,249

Average Time in Queue

Table 12-16 presents information on the time in the stages of the queue for those projects not yet in service. Of the 826 projects in the queue as of December 31, 2017, 62 had a completed feasibility study and 127 were under construction.

26 See PJM. "Manual 14B: PJM Region Transmission Planning Process," Rev. 40 (Oct. 26, 2017), p.82.

27 "Generators planning to connect to the local distribution systems at locations that are not under FERC jurisdiction and wish to participate in PJM's market need to execute a PJM Wholesale Market Participation Agreement (WMPA)…" instead of an ISA. See PJM. "Manual 14C: Generation and Transmission Interconnection Facility Construction," Revision 12 (June 22, 2017).

28 See PJM. "Manual 14C: Generation and Transmission Interconnection Facility Construction," Rev. 12 (June 22, 2017).

Table 12-16 PJM generation planning summary: December 31, 2017

Milestone Reached	Number of Projects	Percent of Total Projects	Average Days	Maximum Days
Under Review	461	55.8%	838	2,039
Feasibility Study	62	7.5%	1,165	1,972
System Impact Study	110	13.3%	1,065	3,194
Facilities Study	66	8.0%	2,226	4,260
Construction Service Agreement (CSA) or beyond	127	15.4%	2,335	4,977
Total	826	100.0%		

Queue Analysis by Fuel Group

The time it takes to complete a study depends on the backlog and the number of projects in the queue, but not on the size of the project. Table 12-17 shows the number of projects that entered the queue by year. The number of queue entries has increased during the past three years, primarily by renewable projects (solar, hydro, storage, biomass, wind). Of the 1,056 projects entered in 2015, 2016, and 2017, 786 projects, 74.4 percent, were renewable. Of the 351 projects entered in 2017, 282 projects, 80.3 percent, were renewable.

Table 12-17 Number of projects entered in the queue: December 31, 2017

	Fuel Group			
Year Entered	Nuclear	Renewable	Traditional	Grand Total
1997	2	0	11	13
1998	0	0	18	18
1999	1	5	85	91
2000	2	3	79	84
2001	4	6	83	93
2002	3	14	33	50
2003	1	35	17	53
2004	4	17	32	53
2005	3	78	51	132
2006	9	78	70	157
2007	9	68	142	219
2008	3	114	99	216
2009	10	113	50	173
2010	5	382	54	441
2011	6	265	78	349
2012	2	73	80	155
2013	1	78	73	152
2014	0	122	68	190
2015	0	192	114	306
2016	2	312	85	399
2017	2	282	67	351
Total	69	2,237	1,389	3,695

Even though renewable projects comprise the majority of projects entered in the queue, as well as what is currently active in the queue, renewable projects only account for 39.7 percent of the nameplate MW currently active in the queue (Table 12-18).

Table 12-18 Queue details by fuel group: December 31, 2017

Fuel Group	Number of Projects	Percent of Projects	MW	Percent MW
Nuclear	8	1.0%	152.3	0.2%
Renewable	588	70.3%	39,808.3	39.7%
Traditional	240	28.7%	60,248.4	60.1%
Total	836	100.0%	100,209.0	100.0%

Queue Analysis by Fuel Type and Project Classification

Table 12-19 shows the current status of all generation queue projects by fuel type and project classification from January 1, 1997, through December 31, 2017. For example, between January 1, 1997 and December 31, 2017, 156 nameplate capacity upgrades at natural gas fired facilities have completed the queue process and are in service.

Since 1997, there have been a total of 3,685 projects in PJM generation queues. A total of 3,001 projects have been classified as new generation and 684 projects have been classified as upgrades. Wind, solar and natural gas projects have accounted for 2,914 projects, or 79.1 percent, of all 3,685 generation queue projects. A total of 20 new projects from either project classification entered the generation queue between October 1, 2017 and December 31, 2017.

Table 12-19 Status of all generation queue projects: 1997 through 2017

		Number of Projects												
Project Status	Project Classification	Biomass	Coal	Diesel	Hydro	LFG	Natural Gas	Nuclear	Oil	Other	Solar	Storage	Wind	TOTAL
In Service	New Generation	7	9	6	11	75	95	1	4	3	122	18	64	415
	Upgrade	6	45	3	17	17	156	42	14	4	16	3	15	338
Under Construction	New Generation	0	0	0	3	2	29	0	0	0	30	23	18	105
	Upgrade	1	4	1	0	0	21	0	0	0	2	2	1	32
Suspended	New Generation	1	0	0	0	0	17	0	0	0	35	6	21	80
	Upgrade	0	0	0	0	0	6	0	0	0	0	4	3	13
Withdrawn	New Generation	38	55	12	40	79	434	9	9	10	794	80	377	1,937
	Upgrade	2	13	1	2	10	80	9	13	2	13	8	16	169
Active	New Generation	0	0	0	1	4	74	1	0	0	316	17	51	464
	Upgrade	1	5	3	2	2	72	7	0	0	28	4	8	132
Total Projects	New Generation	46	64	18	55	160	649	11	13	13	1,297	144	531	3,001
	Upgrade	10	67	8	21	29	335	58	27	6	59	21	43	684

Table 12-20 shows the MW in Table 12-19 by share by classification as new generation or upgrade. Within a fuel type the shares of upgrades add to 100 percent and the shares of new generation add to 100 percent. For example, 81.0 percent of all hydro projects classified as upgrades are currently in service in PJM, 9.5 percent of hydro upgrades were withdrawn and 9.5 percent of hydro upgrades are active in the queue. From January 1, 1997, through December 31, 2017, nuclear projects have had the lowest completion rate across all technology types for projects classified as new generation and storage projects have had the lowest completion rate across all technology types for projects classified as upgrades. Landfill gas projects have had the highest completion rate across all technology types for projects classified as new generation and hydro projects have had the highest completion rate across all technology types for projects classified as upgrades.

Table 12-20 Status of all generation queue projects as a percent of total projects by classification: 1997 through 2017

		Percent of Total Projects by Classification											
Project Status	Project Classification	Biomass	Coal	Diesel	Hydro	LFG	Natural Gas	Nuclear	Oil	Other	Solar	Storage	Wind
In Service	New Generation	15.2%	14.1%	33.3%	20.0%	46.9%	14.6%	9.1%	30.8%	23.1%	9.4%	12.5%	12.1%
	Upgrade	60.0%	67.2%	37.5%	81.0%	58.6%	46.6%	72.4%	51.9%	66.7%	27.1%	14.3%	34.9%
Under Construction	New Generation	0.0%	0.0%	0.0%	5.5%	1.3%	4.5%	0.0%	0.0%	0.0%	2.3%	16.0%	3.4%
	Upgrade	10.0%	6.0%	12.5%	0.0%	0.0%	6.3%	0.0%	0.0%	0.0%	3.4%	9.5%	2.3%
Suspended	New Generation	2.2%	0.0%	0.0%	0.0%	0.0%	2.6%	0.0%	0.0%	0.0%	2.7%	4.2%	4.0%
	Upgrade	0.0%	0.0%	0.0%	0.0%	0.0%	1.8%	0.0%	0.0%	0.0%	0.0%	19.0%	7.0%
Withdrawn	New Generation	82.6%	85.9%	66.7%	72.7%	49.4%	66.9%	81.8%	69.2%	76.9%	61.2%	55.6%	71.0%
	Upgrade	20.0%	19.4%	12.5%	9.5%	34.5%	23.9%	15.5%	48.1%	33.3%	22.0%	38.1%	37.2%
Active	New Generation	0.0%	0.0%	0.0%	1.8%	2.5%	11.4%	9.1%	0.0%	0.0%	24.4%	11.8%	9.6%
	Upgrade	10.0%	7.5%	37.5%	9.5%	6.9%	21.5%	12.1%	0.0%	0.0%	47.5%	19.0%	18.6%

Table 12-21 shows the nameplate generating capacity of projects in the PJM generation queue by technology type and project classification. For example, the 377 new generation wind projects that have been withdrawn from the queue as of December 31, 2017, listed in Table 12-19 constitute 59,559.4 MW of nameplate capacity. The 514 new generation and upgrade natural gas projects that have been withdrawn in the same time period constitute 197,711.7 MW of nameplate capacity.

Table 12-21 Status of all generation capacity (MW) in the PJM generation queue: 1997 through 2017

Project Status	Project Classification	Biomass	Coal	Diesel	Hydro	LFG	Natural Gas	Nuclear	Oil	Other	Solar	Storage	Wind	TOTAL
In Service	New Generation	225.7	1,378.0	69.5	578.1	407.0	26,919.1	9.0	607.0	50.0	1,141.4	161.4	7,009.6	38,555.7
	Upgrade	58.8	747.5	25.3	622.6	54.5	6,820.5	3,912.8	125.8	547.5	19.4	36.4	33.7	13,004.7
Under Construction	New Generation	0.0	0.0	0.0	23.1	11.2	13,707.2	0.0	0.0	0.0	510.8	40.6	3,011.3	17,304.2
	Upgrade	62.5	108.0	0.0	0.0	0.0	1,455.1	0.0	0.0	0.0	4.5	52.0	0.0	1,682.1
Suspended	New Generation	16.0	0.0	0.0	0.0	0.0	4,554.5	0.0	0.0	0.0	396.4	75.8	3,657.7	8,700.4
	Upgrade	0.0	0.0	0.0	0.0	0.0	430.7	0.0	0.0	0.0	0.0	50.0	175.0	655.7
Withdrawn	New Generation	1,061.5	33,511.6	63.9	1,988.0	448.4	188,838.1	8,161.0	1,721.0	843.8	14,645.4	815.9	59,559.3	311,658.0
	Upgrade	37.1	865.0	4.0	56.0	48.7	8,873.6	916.0	589.0	24.0	169.1	142.1	384.6	12,109.2
Active	New Generation	0.0	0.0	0.0	15.0	29.4	34,269.7	28.0	0.0	0.0	17,770.8	276.9	11,177.4	63,567.1
	Upgrade	4.0	91.0	7.0	39.5	2.0	5,582.6	124.3	0.0	0.0	1,397.3	28.8	266.5	7,542.9
Total Projects	New Generation	1,303.2	34,889.6	133.4	2,604.2	896.0	268,288.6	8,198.0	2,328.0	893.8	34,464.8	1,370.5	84,415.4	439,785.5
	Upgrade	162.4	1,811.5	36.3	718.1	105.2	23,162.5	4,953.1	714.8	571.5	1,590.3	309.3	859.8	34,994.6

Figure 12-3 shows the project MW that have entered the PJM generation queue by fuel type and year of entry. In 2015 and 2016, natural gas, wind, and solar projects accounted for the majority of all new projects entering the generation queue. The increase in solar projects entering the queue in 2016 from 2015 was primarily a result of new projects in Dominion. The increase in solar projects entering the queue in 2017 was primarily a result of new projects in AEP.

Figure 12-3 Queue project MW by fuel type and queue entry year: 1997 through 2017

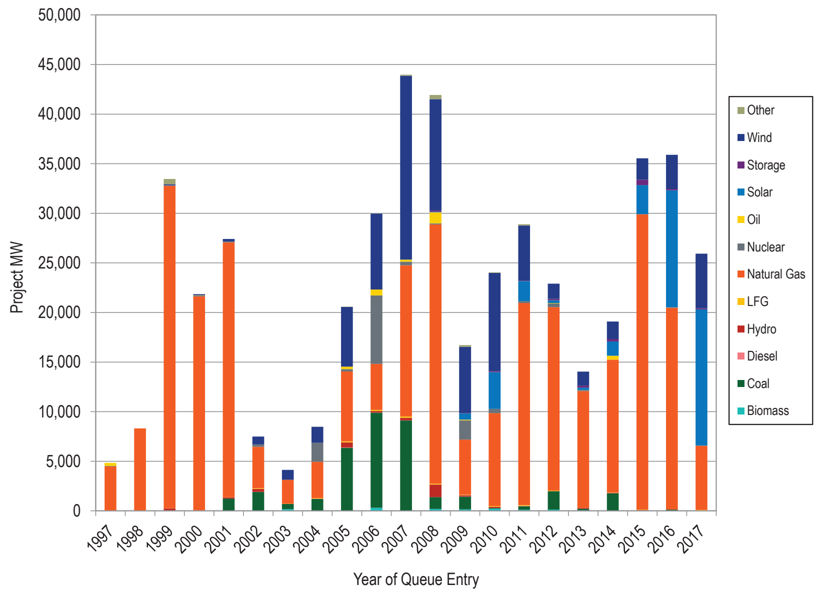


Table 12-22 shows the MW in Table 12-21 by share by classification as new generation or upgrade. Within a fuel type the shares of upgrades add to 100 percent and the shares of new generation add to 100 percent. For example, 70.6 percent of wind projects classified as new generation have been withdrawn from the queue between January 1, 1997, and December 31, 2017.

Table 12-22 Status of all generation queue projects as percent of total MW in project classification: 1997 through 2017

		Percent of Total Project MW by Classification											
Project Status	Project Classification	Biomass	Coal	Diesel	Hydro	LFG	Natural Gas	Nuclear	Oil	Other	Solar	Storage	Wind
In Service	New Generation	17.3%	3.9%	52.1%	22.2%	45.4%	10.0%	0.1%	26.1%	5.6%	3.3%	11.8%	8.3%
	Upgrade	36.2%	41.3%	69.7%	86.7%	51.8%	29.4%	79.0%	17.6%	95.8%	1.2%	11.8%	3.9%
Under Construction	New Generation	0.0%	0.0%	0.0%	0.9%	1.2%	5.1%	0.0%	0.0%	0.0%	1.5%	3.0%	3.6%
	Upgrade	38.5%	6.0%	0.0%	0.0%	0.0%	6.3%	0.0%	0.0%	0.0%	0.3%	16.8%	0.0%
Suspended	New Generation	1.2%	0.0%	0.0%	0.0%	0.0%	1.7%	0.0%	0.0%	0.0%	1.2%	5.5%	4.3%
	Upgrade	0.0%	0.0%	0.0%	0.0%	0.0%	1.9%	0.0%	0.0%	0.0%	0.0%	16.2%	20.4%
Withdrawn	New Generation	81.5%	96.1%	47.9%	76.3%	50.0%	70.4%	99.5%	73.9%	94.4%	42.5%	59.5%	70.6%
	Upgrade	22.8%	47.8%	11.0%	7.8%	46.3%	38.3%	18.5%	82.4%	4.2%	10.6%	45.9%	44.7%
Active	New Generation	0.0%	0.0%	0.0%	0.6%	3.3%	12.8%	0.3%	0.0%	0.0%	51.6%	20.2%	13.2%
	Upgrade	2.5%	5.0%	19.3%	5.5%	1.9%	24.1%	2.5%	0.0%	0.0%	87.9%	9.3%	31.0%

Natural Gas Project Analysis

Table 12-23 shows the status of all natural gas projects by number of projects that entered PJM generation queues from January 1, 1997 through December 31, 2017, by zone. Of the 134 natural gas projects classified either as new generation or upgrade currently active in the PJM generation queue, 50 projects, 37.3 percent, are located within AEP, ComEd and APS.

Table 12-23 Status of all natural gas generation queue projects: 1997 through 2017

		Number of Projects																			
Project Status	Project Classification	AECO	AEP	APS	ATSI	BGE	ComEd	DAY	DEOK	Dominion	DPL	DLCO	EKPC	JCPL	Met-Ed	PECO	PENELEC	Pepco	PPL	PSEG	RECO	TOTAL
In Service	New Generation	7	2	0	2	6	2	0	1	5	8	0	0	8	4	6	8	7	9	12	0	87
	Upgrade	7	15	0	1	1	12	6	0	31	15	0	0	5	2	9	5	5	6	27	0	147
Under Construction	New Generation	3	1	0	1	1	0	0	1	3	0	1	0	1	1	2	2	2	5	2	0	26
	Upgrade	0	1	0	1	0	2	0	0	2	0	0	0	1	0	5	0	1	4	3	0	20
Suspended	New Generation	1	2	0	0	0	0	0	0	0	0	0	0	1	0	0	7	1	0	0	0	12
	Upgrade	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	1	2	0	0	0	4
Withdrawn	New Generation	26	18	0	13	8	10	0	1	17	17	2	3	25	25	42	50	33	40	63	2	395
	Upgrade	6	7	0	4	0	2	0	1	7	4	0	0	5	8	3	4	3	5	16	0	75
Active	New Generation	5	11	0	4	0	11	1	0	3	2	0	1	1	0	1	5	0	4	19	0	68
	Upgrade	4	11	0	5	0	17	0	0	11	1	0	0	3	2	1	5	1	4	1	0	66
Total Projects	New Generation	42	34	0	20	15	23	1	3	28	27	3	4	36	30	51	72	43	58	96	2	588
	Upgrade	17	34	0	11	1	33	6	1	51	20	0	0	15	12	18	15	12	19	47	0	312

Table 12-24 shows the status of all gas projects by MW that entered PJM generation queues from January 1, 1997 through December 31, 2017, by zone. Of the 36,126.7 MW of natural gas projects classified either as new generation or upgrade currently active in the PJM generation queue, 17,085.2 MW, 47.3 percent, are located within AEP, ComEd and APS.

Table 12-24 Status of all natural gas generation capacity (MW) in the PJM generation queue: 1997 through 2017

Project Status	Project Classification	Project MW										
		AECO	AEP	APS	ATSI	BGE	ComEd	DAY	DEOK	Dominion	DPL	DLCO
In Service	New Generation	1,016.2	1,322.0	0.0	815.5	390.0	629.0	0.0	20.0	4,011.0	1,587.2	0.0
	Upgrade	265.7	414.0	0.0	40.0	2.5	864.0	60.0	0.0	1,476.7	198.0	0.0
Under Construction	New Generation	453.5	675.0	0.0	800.0	1.3	0.0	0.0	513.0	2,855.1	0.0	205.0
	Upgrade	0.0	6.0	0.0	161.0	0.0	32.6	0.0	0.0	195.0	0.0	0.0
Suspended	New Generation	235.0	1,579.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Withdrawn	New Generation	6,923.8	9,632.0	0.0	5,420.7	3,122.1	4,533.0	0.0	134.5	10,475.0	4,842.4	665.0
	Upgrade	122.8	711.0	0.0	111.0	0.0	75.0	0.0	36.0	305.3	668.0	0.0
Active	New Generation	1,176.4	7,203.0	0.0	4,047.0	0.0	6,779.2	1,150.0	0.0	3,544.5	1,051.0	0.0
	Upgrade	273.6	441.0	0.0	253.0	0.0	2,662.0	0.0	0.0	410.1	60.0	0.0
Total Projects	New Generation	9,805.0	20,411.0	0.0	11,083.2	3,513.4	11,941.2	1,150.0	667.5	20,885.6	7,480.6	870.0
	Upgrade	662.1	1,572.0	0.0	565.0	2.5	3,633.6	60.0	36.0	2,387.1	926.0	0.0

Project Status	Project Classification	Project MW									
		EKPC	JCPL	Met-Ed	PECO	PENELEC	Pepco	PPL	PSEG	RECO	TOTAL
In Service	New Generation	0.0	2,070.3	2,117.0	2,464.0	1,267.1	842.0	2,826.9	2,804.9	0.0	24,183.1
	Upgrade	0.0	224.0	44.1	780.5	87.0	121.1	327.3	1,057.9	0.0	5,962.8
Under Construction	New Generation	0.0	0.4	450.0	760.5	1,640.0	755.0	3,074.0	570.0	0.0	12,752.8
	Upgrade	0.0	0.0	0.0	241.0	0.0	64.5	524.0	231.0	0.0	1,455.1
Suspended	New Generation	0.0	440.0	0.0	0.0	146.8	894.0	0.0	0.0	0.0	3,294.8
	Upgrade	0.0	200.0	0.0	0.0	1.6	144.1	0.0	0.0	0.0	345.7
Withdrawn	New Generation	991.8	11,461.2	13,001.0	23,120.0	17,030.9	20,414.2	16,795.7	23,524.0	6.9	172,094.1
	Upgrade	0.0	253.0	1,742.0	240.0	1,040.6	85.0	500.0	2,404.9	0.0	8,294.6
Active	New Generation	75.0	1,092.2	0.0	220.0	685.9	0.0	1,554.8	2,394.8	0.0	30,973.8
	Upgrade	0.0	109.9	65.0	88.0	328.2	75.0	336.0	51.1	0.0	5,152.9
Total Projects	New Generation	1,066.8	15,064.1	15,568.0	26,564.5	20,770.7	22,905.2	24,251.4	29,293.6	6.9	243,298.6
	Upgrade	0.0	786.9	1,851.1	1,349.5	1,457.4	489.7	1,687.3	3,744.9	0.0	21,211.1

Wind Project Analysis

Table 12-25 shows the status of all wind generation projects that entered PJM generation queues from January 1, 1997 through December 31, 2017, by zone. Of the 65 wind projects to achieve in service status, 56 projects, 86.2 percent are located within ComEd, AEP, APS and PENELEC. Of the 53 wind projects currently active in the PJM generation queue, 43 projects, 81.1 percent are located within ComEd, AEP, APS and PENELEC.

Table 12-25 Status of all wind generation queue projects: 1997 through 2017

Project Status	Project Classification	Number of Projects																				
		AECO	AEP	APS	ATSI	BGE	ComEd	DAY	DEOK	Dominion	DPL	DLCO	EKPC	JCPL	Met-Ed	PECO	PENELEC	Pepco	PPL	PSEG	RECO	TOTAL
In Service	New Generation	1	11	0	0	0	17	0	0	0	0	0	0	0	0	0	20	0	4	0	0	53
	Upgrade	0	0	0	0	0	2	0	0	0	0	0	0	0	0	0	6	0	4	0	0	12
Under Construction	New Generation	0	3	0	0	0	4	0	0	4	1	0	0	0	0	0	1	0	0	0	0	13
	Upgrade	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Suspended	New Generation	1	10	0	1	0	1	2	0	1	0	0	0	0	0	0	2	0	1	0	0	19
	Upgrade	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2
Withdrawn	New Generation	15	83	0	6	0	95	13	0	16	7	0	1	0	0	0	61	0	40	1	0	338
	Upgrade	1	0	0	0	0	1	0	0	2	0	0	0	0	0	0	4	0	2	0	0	10
Active	New Generation	0	22	0	3	0	14	0	0	2	2	0	0	0	0	0	1	0	3	0	0	47
	Upgrade	0	0	0	0	0	4	0	0	0	0	0	0	0	0	0	2	0	0	0	0	6
Total Projects	New Generation	17	129	0	10	0	131	15	0	23	10	0	1	0	0	0	85	0	48	1	0	470
	Upgrade	2	1	0	0	0	7	0	0	2	0	0	0	0	0	0	12	0	6	0	0	30

Table 12-26 shows the wind project capacity in MW of all wind generation projects that have entered the PJM generation queue from January 1, 1997 through December 31, 2017, by zone. Of the 6,039.3 MW of wind generation capacity to achieve in service status, 5,805.3 MW, or 96. percent of nameplate capacity is located within ComEd, AEP, APS and PENELEC. Of the 11,066.9 MW of wind generation capacity currently active in the PJM generation queue, 9,183.6 MW of generation capacity or 83.0 percent is located within ComEd, AEP, APS and PENELEC.

Table 12-26 Status of all wind generation capacity (MW) in the PJM generation queue: 1997 through 2017

Project Status	Project Classification	Project MW										
		AECO	AEP	APS	ATSI	BGE	ComEd	DAY	DEOK	Dominion	DPL	DLCO
In Service	New Generation	7.5	2,390.4	0.0	0.0	0.0	2,413.5	0.0	0.0	0.0	0.0	0.0
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Under Construction	New Generation	0.0	499.9	0.0	0.0	0.0	978.5	0.0	0.0	740.3	150.0	0.0
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Suspended	New Generation	20.0	1,830.0	0.0	500.0	0.0	500.0	300.0	0.0	76.6	0.0	0.0
	Upgrade	5.0	100.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Withdrawn	New Generation	3,626.4	15,596.4	0.0	645.6	0.0	22,315.8	1,828.0	0.0	2,361.5	2,255.0	0.0
	Upgrade	0.0	0.0	0.0	0.0	0.0	4.0	0.0	0.0	82.0	0.0	0.0
Active	New Generation	0.0	5,853.7	0.0	816.1	0.0	2,945.5	0.0	0.0	226.6	499.6	0.0
	Upgrade	0.0	0.0	0.0	0.0	0.0	175.7	0.0	0.0	0.0	0.0	0.0
Total Projects	New Generation	3,653.9	26,170.4	0.0	1,961.7	0.0	29,153.3	2,128.0	0.0	3,405.0	2,904.6	0.0
	Upgrade	5.0	100.0	0.0	0.0	0.0	179.7	0.0	0.0	82.0	0.0	0.0

Project Status	Project Classification	Project MW									
		EKPC	JCPL	Met-Ed	PECO	PENELEC	Pepco	PPL	PSEG	RECO	TOTAL
In Service	New Generation	0.0	0.0	0.0	0.0	995.0	0.0	199.2	0.0	0.0	6,005.6
	Upgrade	0.0	0.0	0.0	0.0	6.4	0.0	27.3	0.0	0.0	33.7
Under Construction	New Generation	0.0	0.0	0.0	0.0	70.0	0.0	0.0	0.0	0.0	2,438.7
	Upgrade	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	180.0	0.0	100.0	0.0	0.0	3,506.6
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	105.0
Withdrawn	New Generation	150.3	0.0	0.0	0.0	5,059.0	0.0	2,766.3	20.0	0.0	56,624.3
	Upgrade	0.0	0.0	0.0	0.0	192.6	0.0	6.0	0.0	0.0	284.6
Active	New Generation	0.0	0.0	0.0	0.0	138.0	0.0	341.1	0.0	0.0	10,820.4
	Upgrade	0.0	0.0	0.0	0.0	70.8	0.0	0.0	0.0	0.0	246.5
Total Projects	New Generation	150.3	0.0	0.0	0.0	6,442.0	0.0	3,406.6	20.0	0.0	79,395.6
	Upgrade	0.0	0.0	0.0	0.0	269.7	0.0	33.3	0.0	0.0	669.8

Solar Project Analysis

Table 12-27 shows the status of all solar generation projects that have entered the PJM generation queue from January 1, 1997 through December 31, 2017, by zone. Of a total of 1,269 solar projects ever to enter the PJM generation queue, 515 projects, or 40.6 percent, have been located in JCPL, AECO and PSEG, all zones in New Jersey. Of these three zones, AECO has the lowest completion rates for new generation and upgrade solar projects. Excluding currently active projects, only 4.3 percent of solar projects classified as new generation or upgrades in AECO are either in service or under construction. Of these three zones, PSEG has the highest completion rates. Excluding currently active projects, 40.4 percent of solar projects classified as either new generation or upgrades in PSEG are either in service or under construction.

The number of currently active new generation solar projects is also highly concentrated in several zones. Out of 332 active new generation solar projects, 141 projects, or 42.5 percent of all currently active new generation solar projects are located in Dominion. Out of 141 active new generation solar projects, 69, or 20.8 percent of all currently active new generation solar projects are located in AEP.

Table 12-27 Status of all solar generation queue projects: 1997 through 2017

Project Status	Project Classification	Number of Projects																				
		AECO	AEP	APS	ATSI	BGE	ComEd	DAY	DEOK	Dominion	DPL	DLCO	EKPC	JCPL	Met-Ed	PECO	PENELEC	Pepco	PPL	PSEG	RECO	TOTAL
In Service	New Generation	7	4	0	0	1	1	1	0	15	9	0	0	39	0	1	0	0	2	38	0	118
	Upgrade	0	0	0	0	0	0	0	0	2	8	0	0	6	0	0	0	0	0	0	0	16
Under Construction	New Generation	0	2	0	0	2	0	1	0	5	5	0	0	8	0	0	0	0	0	6	0	29
	Upgrade	0	0	0	0	0	0	0	0	1	1	0	0	0	0	0	0	0	0	0	0	2
Suspended	New Generation	0	5	0	0	0	0	1	0	1	1	0	0	6	1	0	1	0	0	2	0	18
	Upgrade	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Withdrawn	New Generation	155	52	0	7	10	9	8	10	97	101	0	3	163	12	6	10	9	27	62	0	741
	Upgrade	1	1	0	0	0	0	0	0	5	0	0	0	5	0	0	0	0	0	1	0	13
Active	New Generation	4	66	0	5	0	23	10	3	125	45	1	2	2	2	1	1	4	2	9	0	305
	Upgrade	0	3	0	0	0	1	0	2	16	1	1	0	1	1	0	0	0	1	0	0	27
Total Projects	New Generation	166	129	0	12	13	33	21	13	243	161	1	5	218	15	8	12	13	31	117	0	1211
	Upgrade	1	4	0	0	0	1	0	2	24	10	1	0	12	1	0	0	0	1	1	0	58

Table 12-28 shows the status of all solar generation project MW that have entered the PJM generation queue from January 1, 1997 through December 31, 2017, by zone. Of a total of 34,144.4 MW of solar nameplate capacity ever to enter the PJM generation queue, 4,260.6 MW, or 12.5 percent, have been located in JCPL, AECO and PSEG, all of which are zones in New Jersey. Solar projects in Dominion have accounted for 14,291.2 MW or 41.9 percent of all solar project nameplate capacity in the PJM queue from January 1, 1997 through December 31, 2017. Solar projects in DPL have accounted for 2,891.0 MW or 8.5 percent of all solar project nameplate capacity in the PJM queue from January 1, 1997 through December 31, 2017.

Table 12-28 Current status of all solar generation capacity (MW) in the PJM generation queue: 1997 through 2017

	Project	Project MW										
Project Status	Classification	AECO	AEP	APS	ATSI	BGE	ComEd	DAY	DEOK	Dominion	DPL	DLCO
In Service	New Generation	57.3	14.7	0.0	0.0	1.1	9.0	2.5	0.0	409.2	118.4	0.0
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.1	0.0	0.0
Under Construction	New Generation	0.0	30.0	0.0	0.0	22.0	0.0	3.4	0.0	238.5	43.0	0.0
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.5	0.0	0.0
Suspended	New Generation	0.0	59.9	0.0	0.0	0.0	0.0	20.0	0.0	5.0	6.0	0.0
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Withdrawn	New Generation	1,664.3	2,592.9	0.0	116.1	31.3	176.8	250.5	159.4	4,236.4	1,385.9	0.0
	Upgrade	10.0	6.0	0.0	0.0	0.0	0.0	0.0	0.0	128.0	0.0	0.0
Active	New Generation	24.2	4,663.6	0.0	646.0	0.0	1,025.5	739.5	215.0	8,296.0	1,317.7	11.7
	Upgrade	0.0	210.0	0.0	0.0	0.0	0.0	0.0	85.0	970.5	20.0	8.3
Total Projects	New Generation	1,745.8	7,361.2	0.0	762.1	54.4	1,211.3	1,015.9	374.4	13,185.1	2,871.0	11.7
	Upgrade	10.0	216.0	0.0	0.0	0.0	0.0	0.0	85.0	1,106.1	20.0	8.3

	Project	Project MW									
Project Status	Classification	EKPC	JCPL	Met-Ed	PECO	PENELEC	Pepco	PPL	PSEG	RECO	TOTAL
In Service	New Generation	0.0	266.9	0.0	3.3	0.0	0.0	15.0	191.0	0.0	1,088.4
	Upgrade	0.0	16.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	19.4
Under Construction	New Generation	0.0	127.4	0.0	0.0	0.0	0.0	0.0	36.6	0.0	500.8
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.5
Suspended	New Generation	0.0	59.1	3.0	0.0	13.5	0.0	0.0	8.4	0.0	174.9
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Withdrawn	New Generation	189.9	1,311.3	467.0	51.4	34.3	122.1	283.7	427.7	0.0	13,501.0
	Upgrade	0.0	23.8	0.0	0.0	0.0	0.0	0.0	1.3	0.0	169.1
Active	New Generation	100.0	1.8	135.0	18.0	50.0	65.3	30.0	24.8	0.0	17,364.0
	Upgrade	0.0	8.5	20.0	0.0	0.0	0.0	0.0	0.0	0.0	1,322.3
Total Projects	New Generation	289.9	1,766.4	605.0	72.7	97.8	187.3	328.7	688.6	0.0	32,629.1
	Upgrade	0.0	48.6	20.0	0.0	0.0	0.0	0.0	1.3	0.0	1,515.3

Relationship Between Project Developer and Transmission Owner

Table 12-29 shows the relationship between the project developer and Transmission Owner for all project MW that have entered the PJM generation queue from January 1, 1997, through December 31, 2017, by zone and technology type. A project where the developer is or 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 natural gas fired generation projects that have entered the PJM generation queue in DEOK were projects developed by Duke Energy or subsidiaries of Duke Energy, the Transmission Owner for DEOK. These project MW are classified as related. There have been 154.5 MW of natural gas fired projects that have entered the PJM generation queue in DEOK by developers not affiliated with Duke Energy. These project MW are classified as "unrelated."

Table 12-29 Relationship between project developer and Transmission Owner for all interconnection queue projects MW by fuel type: 1997 through 2017

				MW by Fuel Type										
Parent Company	Transmission Owner	Related To Developer	Number of Projects	Biomass	Coal	Diesel	Hydro	Landfill Gas	Natural Gas	Nuclear	Other	Solar	Wind	Total MW
AEP	AEP	Related	51	0.0	3,965.0	0.0	34.0	3.0	3,027.0	214.0	0.0	301.7	0.0	7,544.7
		Unrelated	413	501.1	10,292.0	7.5	448.4	83.8	24,300.0	0.0	66.0	7,658.8	26,967.0	70,324.5
AES	DAY	Related	17	0.0	1,347.5	0.0	0.0	0.0	51.0	0.0	0.0	74.0	0.0	1,472.5
		Unrelated	39	1.9	0.0	0.0	0.0	10.0	9.0	0.0	0.0	871.9	2,128.0	3,020.8
DLCO	DLCO	Related	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	23	0.0	2,810.0	0.0	106.0	19.2	870.0	1,879.0	0.0	63.3	0.0	5,747.5
Dominion	Dominion	Related	86	64.0	301.0	0.0	340.0	0.0	13,215.0	1,944.0	0.0	496.1	142.0	16,502.1
		Unrelated	362	343.7	20.0	10.0	35.1	184.0	12,105.1	0.0	156.3	17,168.7	3,067.0	33,089.9
Duke	DEOK	Related	4	0.0	0.0	0.0	0.0	0.0	36.0	0.0	0.0	0.0	0.0	36.0
		Unrelated	26	0.0	120.0	0.0	112.0	4.8	154.5	0.0	0.0	509.3	0.0	900.6
EKPC	EKPC	Related	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	10	0.0	0.0	0.0	0.0	0.0	2,216.8	0.0	0.0	240.0	150.3	2,607.1
Exelon	AECO	Related	3	0.0	0.0	0.0	0.0	0.0	730.0	0.0	0.0	0.0	0.0	730.0
		Unrelated	273	29.8	15.0	13.0	0.0	31.0	9,791.8	0.0	0.0	1,786.3	3,808.9	15,475.8
	BGE	Related	14	0.0	10.0	0.0	0.0	0.0	1,037.0	3,373.3	0.0	20.0	0.0	4,440.3
		Unrelated	59	0.0	0.0	29.0	140.4	9.5	4,152.9	0.0	132.0	34.4	0.0	4,498.2
	ComEd	Related	18	0.0	0.0	0.0	0.0	0.0	0.0	1,185.0	0.0	9.0	396.0	1,590.0
		Unrelated	277	90.0	1,926.0	42.0	22.7	112.9	15,669.4	0.0	20.0	1,238.3	28,784.5	47,905.8
	DPL	Related	10	0.0	0.0	0.0	0.0	0.0	1,716.0	0.0	0.0	31.4	0.0	1,747.4
		Unrelated	267	84.0	653.0	0.0	0.0	70.0	7,373.6	0.0	30.0	2,996.9	2,809.6	14,017.1
	PECO	Related	29	0.0	7.0	0.0	45.0	0.0	6,420.0	437.8	0.0	0.0	0.0	6,909.8
		Unrelated	79	0.0	0.0	12.1	220.0	18.7	21,578.8	0.0	0.0	73.4	0.0	21,903.0
	Pepco	Related	1	0.0	0.0	0.0	0.0	0.0	0.0	1,640.0	0.0	0.0	0.0	1,640.0
		Unrelated	70	0.0	0.0	0.0	0.0	12.5	22,698.9	0.0	0.0	200.3	0.0	22,911.7
First Energy	APS	Related	14	0.0	1,745.0	0.0	252.0	0.0	4,790.0	0.0	0.0	0.0	0.0	6,787.0
		Unrelated	320	177.2	4,057.0	53.8	371.3	125.8	22,588.4	0.0	96.0	2,095.7	5,522.7	35,087.8
	ATSI	Related	8	0.0	0.0	0.0	0.0	0.0	1,678.0	16.0	0.0	0.6	0.0	1,694.6
		Unrelated	57	0.0	0.0	0.0	0.0	35.3	9,154.7	0.0	135.0	564.5	1,961.7	11,851.2
	JCPL	Related	3	0.0	0.0	0.0	20.0	0.0	100.0	0.0	0.0	8.5	0.0	128.5
		Unrelated	324	30.0	0.0	0.0	1.6	24.4	15,796.0	0.0	0.0	1,828.9	90.6	17,771.4
	Met-Ed	Related	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	90	90.4	0.0	8.0	0.0	57.9	16,839.6	93.0	11.0	625.0	70.0	17,794.9
	PENELEC	Related	8	0.0	1,860.0	0.0	32.0	0.0	1,174.0	0.0	0.0	0.0	0.0	3,066.0
		Unrelated	223	0.0	561.0	8.0	53.3	50.9	20,796.8	0.0	621.0	177.8	6,454.1	28,722.8
PPL	PPL	Related	36	0.0	139.0	0.0	0.0	7.7	2,294.0	1,988.0	0.0	0.0	0.0	4,428.7
		Unrelated	192	28.5	6,868.6	10.4	2.6	99.5	21,726.5	0.0	152.5	329.8	3,380.8	32,599.2
PSEG	PSEG	Related	104	0.0	24.0	0.0	0.0	11.7	12,802.1	381.0	0.0	142.2	0.0	13,361.0
		Unrelated	184	0.0	0.0	0.0	1,000.0	24.4	18,676.0	0.0	45.5	567.5	20.0	20,333.3
Consolidated Edison, Inc.	RECO	Related	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	2	0.0	0.0	0.0	0.0	0.0	7.1	0.0	0.0	0.0	0.0	7.1
Total		Related	406	64.0	9,398.5	0.0	723.0	22.4	49,070.1	11,179.1	0.0	1,083.5	538.0	72,078.5
		Unrelated	3,290	1,376.6	27,322.6	193.8	2,513.4	974.6	246,505.8	1,972.0	1,465.3	39,030.6	85,215.1	406,569.7

Table 12-30 shows the relationship between the project developer and Transmission Owner for all solar project MW that have entered the PJM generation queue from January 1, 1997 through December 31, 2017, by zone and project status. Of the 1,319.1 solar project MW that have achieved in service or under construction status during this time period, 186.9 MW, or 14.2 percent have been developed by Transmission Owners building in their own service territory. Of that 186.9 MW of solar projects, 115.8 MW or 62.0 percent have been developed by PSEG in the PSEG Zone and 20.0 MW or 10.7 percent have been developed by Dominion in the Dominion Zone.

Table 12-30 Relationship between project developer and transmission owner for all solar projects MW in PJM interconnection queue: 1997 through 2017

			MW by Project Status					
Parent Company	Transmission Owner	Related To Developer	In Service	Under Construction	Suspended	Withdrawn	Active	Total MW
AEP	AEP	Related	2.5	12.2	0.0	0.0	60.0	74.7
		Unrelated	0.0	20.0	51.7	1,046.5	5,505.9	6,624.1
AES	DAY	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	2.5	23.4	0.0	151.5	468.5	645.9
DLCO	DLCO	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	0.0	0.0	40.0	40.0
Dominion	Dominion	Related	20.0	0.0	0.0	81.9	224.4	326.3
		Unrelated	140.1	122.9	205.0	2,083.5	12,996.0	15,547.5
Duke	DEOK	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	0.0	159.4	290.0	449.4
EKPC	EKPC	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	0.0	80.0	160.0	240.0
Exelon	AECO	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	38.5	20.8	0.0	1,638.8	88.1	1,786.3
	BGE	Related	0.0	20.0	0.0	0.0	0.0	20.0
		Unrelated	1.1	2.0	0.0	9.2	22.1	34.4
	ComEd	Related	9.0	0.0	0.0	0.0	0.0	9.0
		Unrelated	0.0	0.0	0.0	84.8	337.0	421.8
	DPL	Related	7.4	0.0	0.0	24.0	0.0	31.4
		Unrelated	21.0	159.5	0.0	1,126.5	1,679.9	2,986.9
	PECO	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	3.3	0.0	0.0	50.1	20.0	73.4
	Pepco	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	0.0	118.1	60.0	178.1
First Energy	APS	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	34.0	32.5	38.9	806.0	839.3	1,750.7
	ATSI	Related	0.0	0.0	0.0	0.6	0.0	0.6
		Unrelated	0.0	0.0	0.0	59.5	485.0	544.5
	JCPL	Related	0.0	0.0	0.0	0.0	8.5	8.5
		Unrelated	204.1	175.5	92.9	1,266.5	89.7	1,828.7
	Met-Ed	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	3.0	367.0	255.0	625.0
	PENELEC	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	13.5	34.3	50.0	97.8
PPL	PPL	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	15.0	16.0	0.0	268.8	30.0	329.8
PSEG	PSEG	Related	105.8	10.0	0.0	15.2	1.2	132.2
		Unrelated	53.8	46.2	9.7	387.8	60.0	557.5
Consolidated Edison, Inc.	RECO	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0
Total		Related	144.7	42.2	0.0	121.7	294.1	602.7
		Unrelated	513.4	618.8	414.7	9,738.1	23,476.6	34,761.6

Table 12-31 shows the relationship between the project developer and Transmission Owner for all natural gas fired project MW that have entered the PJM generation queue from January 1, 1997 through December 31, 2017, by zone and project status. Of the 46,198.0 natural gas project MW that have achieved in service or under construction status during this time period, 10,382.0 MW, or 22.5 percent have been developed by Transmission Owners building in their own service territory. Of that 10,382.0 MW of natural gas projects, 5,571.0 MW or 53.7 percent have been developed by Dominion in the Dominion Zone and 1,972.0 MW or 19.0 percent have been developed by PSEG in the PSEG Zone.

Table 12-31 Relationship between project developer and transmission owner for all natural gas project MW in PJM interconnection queue: 1997 through 2017

			MW by Project Status					
Parent Company	Transmission Owner	Related To Developer	In Service	Under Construction	Suspended	Withdrawn	Active	Total MW
AEP	AEP	Related	717.0	0.0	0.0	0.0	2,310.0	3,027.0
		Unrelated	1,142.0	3,355.0	525.0	9,008.0	10,270.0	24,300.0
AES	DAY	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	60.0	0.0	0.0	0.0	0.0	60.0
DLCO	DLCO	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	205.0	0.0	665.0	0.0	870.0
Dominion	Dominion	Related	3,823.0	1,748.0	0.0	7,476.0	168.0	13,215.0
		Unrelated	771.7	1,799.1	0.0	3,949.3	5,585.0	12,105.1
Duke	DEOK	Related	0.0	0.0	0.0	36.0	0.0	36.0
		Unrelated	20.0	0.0	0.0	134.5	0.0	154.5
EKPC	EKPC	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	0.0	377.8	1,764.0	2,141.8
Exelon	AECO	Related	0.0	0.0	0.0	730.0	0.0	730.0
		Unrelated	1,281.9	460.5	606.0	6,325.4	1,118.0	9,791.8
	BGE	Related	367.0	0.0	0.0	670.0	0.0	1,037.0
		Unrelated	29.5	1.3	0.0	4,122.1	0.0	4,152.9
	ComEd	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	1,478.5	112.6	0.0	4,023.0	10,055.3	15,669.4
	DPL	Related	411.0	0.0	0.0	1,305.0	0.0	1,716.0
		Unrelated	900.2	0.0	291.0	5,014.4	1,168.0	7,373.6
	PECO	Related	5.0	0.0	0.0	6,415.0	0.0	6,420.0
		Unrelated	3,174.3	892.5	0.0	17,060.0	364.0	21,490.8
	Pepco	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	160.1	2,498.5	0.0	19,854.2	111.1	22,623.9
First Energy	APS	Related	701.0	0.0	0.0	4,089.0	0.0	4,790.0
		Unrelated	1,796.7	962.5	70.1	13,533.6	6,225.5	22,588.4
	ATSI	Related	0.0	0.0	0.0	1,678.0	0.0	1,678.0
		Unrelated	40.0	961.0	0.0	3,833.8	4,249.9	9,084.7
	JCPL	Related	0.0	0.0	0.0	100.0	0.0	100.0
		Unrelated	2,294.3	440.0	200.0	10,879.2	1,982.5	15,796.0
	Met-Ed	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	2,062.0	0.0	0.0	14,216.5	561.1	16,839.6
	PENELEC	Related	5.0	0.0	0.0	1,169.0	0.0	1,174.0
		Unrelated	1,267.8	88.7	59.7	16,426.7	2,553.9	20,396.8
PPL	PPL	Related	633.0	0.0	0.0	1,661.0	0.0	2,294.0
		Unrelated	2,420.9	3,924.0	0.0	12,575.7	2,805.9	21,726.5
PSEG	PSEG	Related	1,972.0	0.0	0.0	9,871.1	959.0	12,802.1
		Unrelated	1,047.8	167.6	0.0	14,906.0	2,554.6	18,676.0
Consolidated Edison, Inc.	RECO	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	0.0	6.9	0.2	7.1
Total		Related	8,634.0	1,748.0	0.0	35,200.1	3,437.0	49,019.1
		Unrelated	19,947.7	15,868.3	1,751.8	156,912.0	51,369.1	245,848.8

Table 12-32 shows the relationship between the project developer and Transmission Owner for all wind project MW that have entered the PJM generation queue from January 1, 1997 through December 31, 2017, by zone and project status. Of the 10,584.3 wind project MW that have achieved in service or under construction status during this time period, 408.0 MW, or 3.9 percent have been developed by Transmission Owners building in their own service territory. Of that 408.0 MW of wind projects, 396.0 MW or 97.1 percent have been developed by Exelon in the ComEd Zone.

Table 12-32 Relationship between project developer and transmission owner for all wind project MW in PJM interconnection queue: 1997 through 2017

			MW by Project Status					
Parent Company	Transmission Owner	Related To Developer	In Service	Under Construction	Suspended	Withdrawn	Active	Total MW
AEP	AEP	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	2,052.0	966.6	1,650.0	14,383.8	6,831.4	25,883.8
AES	DAY	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	300.0	1,828.0	0.0	2,128.0
DLCO	DLCO	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0
Dominion	Dominion	Related	0.0	12.0	0.0	130.0	0.0	142.0
		Unrelated	0.0	673.9	300.0	1,880.9	212.2	3,067.0
Duke	DEOK	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0
EKPC	EKPC	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	0.0	150.3	0.0	150.3
Exelon	AECO	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	7.5	150.0	25.0	3,626.4	0.0	3,808.9
	BGE	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0
	ComEd	Related	396.0	0.0	0.0	0.0	0.0	396.0
		Unrelated	2,238.5	802.5	710.0	20,859.8	2,769.0	27,379.8
	DPL	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	100.0	0.0	2,210.0	499.6	2,809.6
	PECO	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0
	Pepco	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0
First Energy	AP	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	1,031.4	426.0	130.0	3,027.5	747.8	5,362.7
	ATSI	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	500.0	0.0	645.6	315.7	1,461.3
	JCPL	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	30.6	0.0	0.0	60.0	0.0	90.6
	Met-Ed	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	70.0	0.0	0.0	0.0	0.0	70.0
	PENELEC	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	862.5	38.3	150.0	4,927.6	475.8	6,454.1
PPL	PPL	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	226.5	0.0	100.0	2,443.8	610.5	3,380.8
PSEG	PSEG	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	0.0	20.0	0.0	20.0
Consolidated Edison, Inc.	RECO	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0
Total		Related	396.0	12.0	0.0	130.0	0.0	538.0
		Unrelated	6,519.0	3,657.3	3,365.0	56,063.7	12,461.9	82,066.8

Regional Transmission Expansion Plan (RTEP)

Authorized TEAC Transmission Upgrades

The Transmission Expansion Advisory Committee (TEAC) regularly reviews internal and external proposals to improve transmission reliability throughout PJM. These proposals are periodically presented to the PJM Board of Managers for authorization.

- On July 26, 2017, the PJM Board of Managers authorized more than $417 million in electric transmission projects for reliability. The approved projects include a large substation that serves critical infrastructure customers in Newark, N.J., a $275 million PSEG Newark Switch substation project to replace aging equipment, and additional equipment upgrades and improvements in areas served by: American Electric Power; Dominion; Atlantic City Electric Company; PECO Energy Company; Pennsylvania Electric Company; American Transmission Systems, Inc.; East Kentucky Power Cooperative, Inc. and Dayton Power & Light. Most of the individual projects cost less than $5 million.[29]
- On October 18, 2017, the PJM Board of Managers authorized $1 billion in various electric transmission projects including reliability and market efficiency improvements. The approved projects include approximately $300 million in reliability reinforcements to several 69 kV transmission lines in New Jersey. The PJM Board approved upgrades in areas served by American Electric Power; American Transmission Systems, Inc.; Commonwealth Edison; Dominion; East Kentucky Power Cooperative, Inc.; Pennsylvania Electric Company; and Public Service Electric & Gas. Many of the individual projects cost less than $5 million.[30]
- On December 6, 2017, the PJM Board of Managers authorized $318 million in electric transmission projects for reliability. The approved projects include a new $20 million 138 kV transmission line substation project in the ComEd Zone, a $16.5 million rebuild of a 161 kV line in the AEP Zone, and additional projects designed to alleviate reliability issues in northern New Jersey. Many of the individual projects cost less than $5 million.[31]

Backbone Facilities

PJM baseline transmission projects are implemented to resolve reliability criteria violations. PJM backbone transmission projects are a subset of significant baseline projects, which are intended to resolve multiple reliability criteria violations and congestion issues and which may have substantial impacts on energy and capacity markets. There are currently three backbone projects under development, Surry Skiffes Creek 500kV, and the conversion of the Marion-Bayonne and Bayway-Linden lines from 138 kV to 345 kV.[32]

Market Efficiency Process[33]

PJM's Regional Transmission Expansion Plan (RTEP) process includes a market efficiency analysis. The 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 by conducting production cost analyses.[34]

PJM presents all of the RTEP market efficiency enhancements to the TEAC Committee for review and comment. Subsequent to TEAC review, PJM addresses the TEAC review and presents the final RTEP market efficiency plan to the PJM Board, along with the advice, comments, and recommendations of the TEAC Committee, for Board approval.

To be included in the RTEP recommended to the PJM Board of Managers for approval, the relative benefits and costs of the economic based enhancement or

29 See PJM. "*PJM Board approves $417 million investment in transmission improvements*," <http://www.pjm.com/-/media/about-pjm/newsroom/2017-releases/20170726-pjm-board-approves-417-million-investment-in-transmission-improvements.ashx> (July 26, 2017).

30 See PJM. "PJM Board authorizes $1 billion in transmission upgrades," <http://www.pjm.com/-/media/about-pjm/newsroom/2017-releases/20171018-pjm-board-authorizes-1-billion-in-transmission-upgrades.ashx> (October 18, 2017).

31 See PJM. "PJM Board authorizes $317 million in transmission upgrades," <http://www.pjm.com/-/media/about-pjm/newsroom/2017-releases/20171206-pjm-board-approves-rtep-updates-news-release.ashx> (December 6, 2017).

32 See PJM. "*2017 RTEP Process Scope and Input Assumptions White Paper*," P 25. <http://www.pjm.com/-/media/library/reports-notices/2017-rtep/20170731-rtep-input-assumptions-and-scope-whitepaper.ashx?la=en>.

33 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. 40 (Oct. 26, 2017) <http://www.pjm.com/-/media/documents/manuals/m14b.ashx?la=en>.

34 See PJM. "*PJM Regional Transmission Expansion Plan: 2016*," (February 28, 2017). <http://www.pjm.com/-/media/library/reports-notices/2016-rtep/2016-rtep-books-1-3.ashx?la=en>.

expansion must meet a benefit/cost ratio threshold of at least 1.25:1. The benefit/cost ratio is the ratio of the present value of the total annual benefit for 15 years by the present value of the total annual cost for each of 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 upgrades for years five through 15. This long-term proposal window takes place concurrent with the long-term proposal window for reliability projects. [35]

Through December 31, 2017, PJM has completed two market efficiency cycles. In the first cycle, PJM received 92 proposals for 11 identified issues. In the second market efficiency cycle, PJM received 96 proposals for four identified issues.

Supplemental Projects

Supplemental projects are "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."[36] Supplemental projects are funded wholly by the Transmission Owner and no PJM approval is needed. Supplemental projects addressed two of the four issues identified in the most recent market efficiency cycle. Because supplemental projects are considered by transmission owners to be outside the scope of FERC Order No. 1000, supplemental projects may be considered noncompetitive.

The MMU is concerned with the impact of supplemental projects on the market efficiency process. It is not clear how a supplemental project can be used to resolve market efficiency projects that have been identified based on a cost/benefit analysis and why such a project should not be subject to competition. The MMU recommends that PJM limit the scope of supplemental projects that can obtain exceptions to the Order No. 1000 process to ensure maximum competition.

PJM MISO Interregional Targeted Market Efficiency Process (TMEP)

PJM and MISO developed a process to facilitate the construction of interregional projects in response to the Commissions concerns about interregional coordination along the PJM-MISO seam, called the Targeted Market Efficiency Process (TMEP).[37]

The allocation of costs to each RTO for TMEPs will be in proportion to the benefits received.[38]

On November 2, 2017, PJM submitted a compliance filing including additional revisions the MISO-PJM JOA to include stakeholder feedback in the TMEP project selection process.[39] [40]

The first TMEP analysis included the investigation of congestion on 50 market to market flowgates. The study resulted in the evaluation of 13 potential upgrades, resulting in the recommendation of five TMEP projects. The five projects address $59 million in historical congestion, with a TMEP benefit of $99.6 million. The projects have a total cost of $20 million, with a 5.0 average benefit/cost ratio. PJM and MISO presented the five recommended projects to their boards in December, 2017, and both boards approved all five projects.[41]

Artificial Island

Artificial Island is an area in southern New Jersey that includes nuclear units at Salem and at Hope Creek in the PSEG Zone. On April 29, 2013, PJM issued a request for proposal (RFP), seeking technical solutions to improve stability issues and operational performance under a range of anticipated system conditions, and the elimination of potential planning criteria violations in this area. On July 30, 2015, the PJM Board of Managers accepted PJM's recommendation to assign the project

35 See PJM. "*PJM Market Efficiency Modeling Practices*," (February 2, 2017). <http://www.pjm.com/-/media/planning/rtep-dev/market-efficiency/pjm-market-efficiency-modeling-practices.ashx?la=en>.

36 See PJM. "*Transmission Construction Status*," (January 23, 2018) <http://www.pjm.com/planning/rtep-upgrades-status/construct-status.aspx>.

37 See *PJM Interconnection, L.L.C*, Docket No. ER17-718-000 (December 30, 2016).

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

39 See *PJM Interconnection, L.L.C*, Docket No. ER17-718-000, ER17-721-000 and ER17-729-000 (Not Consolidated) (November 2, 2017).

40 161 FERC ¶ 61,005 (2017). *Order accepting filings subject to condition*.

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

to LS Power, a merchant developer, PSEG, and PHI with a total cost estimate between $263M and $283M.[42] [43] On August 5, 2016, PJM announced that the Artificial Island project was to be suspended immediately due to unanticipated project complexities and significant cost overruns. On March 3, 2017, PJM held a special Transmission Expansion Advisory Committee (TEAC) meeting to discuss their updated analysis of the Artificial Island project. PJM staff presented updated assumptions that went into the new project analysis. In consultation with project developers and stakeholders, PJM made several major revisions to the project. These included switching the interconnection point from the Salem Substation to the Hope Creek Substation, removal of the New Freedom switched vertical circuit (SVC) from the project scope, and removal of the optical ground wire (OPGW) from the project scope. These revisions led to a revised total project cost estimate of $280 million, $140 million less than the previous $420 million project cost estimate released in February 2016. On April 6, 2017, the PJM Board lifted a suspension of the project. It is expected to be in service by June 2020.

On October 25, 2012, Schedule 12 of the tariff and Schedule 6 of the OA were changed to address FERC Order No. 1000 reforms to the cost allocation requirements for local and regional transmission planning projects that were formerly defined in Order No. 890. The new approach was applied for the first time to the 2013 RTEP. The allocation process has been upheld by FERC despite repeated challenges.[44]

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.[45] When one of the reportable transmission facilities needs to be taken out of service, the TO is required to submit an outage request as early as possible. The specific timeline is shown in Table 12-34.[46]

Transmission outages have significant impacts on PJM markets. There are impacts on FTR auctions, on congestion, and on expected market outcomes in the day-ahead and real-time markets. It is important for the efficient functioning of the markets that there be clear, enforceable rules governing transmission outages.

Transmission outages are categorized by duration: greater than 30 calendar days; less than or equal to 30 calendar days and greater than five calendar days; or less than or equal to five calendar days.[47] Table 12-33 shows that 73.4 percent of the requested outages were planned for less than or equal to five days and 8.5 percent of requested outages were planned for greater than 30 days in the 2017/2018 planning period. It also shows that 76.9 percent of the requested outages were planned for less than or equal to five days and 7.0 percent of requested outages were planned for greater than 30 days in the 2016/2017 planning period.

All of the outage data in this section except in the analysis for the day-ahead market are for outages scheduled to occur in the planning periods 2016/2017 and 2017/2018, regardless of when they were initially submitted.[48] The outage data in the analysis for the day-ahead market are for outages scheduled to occur from January 1, 2015, through December 31, 2017.

Table 12-33 Transmission facility outage request summary by planned duration: planning periods 2016/2017 and 2017/2018

	2016/2017		2017/2018	
Planned Duration (Days)	Outage Requests	Percent	Outage Requests	Percent
<=5	16,440	76.9%	11,465	73.4%
>5 & <=30	3,448	16.1%	2,817	18.0%
>30	1,489	7.0%	1,331	8.5%
Total	21,377	100.0%	15,613	100.0%

42 See "Artificial Island Recommendations," presented at the TEAC meeting on April 28, 2015 at <http://www.pjm.com/~/media/committees-groups/committees/teac/20150428-ai/20150428-artificial-island-recommendations.ashx>.

43 See letter from Terry Boston concerning the Artificial Island Project at <http://www.pjm.com/-/media/library/reports-notices/special-reports/board-statement-on-artificial-island-project.ashx?la=en>.

44 See 155 FERC ¶ 61,090 (2016); 155 FERC ¶ 61,089 (2016); 155 FERC ¶ 61,088 (2016); see also Order No. 1000, FERC Stats. & Regs. ¶ 31,323 (2011), *order on reh'g*, Order No. 1000-A, 139 FERC ¶ 61,132, *order on reh'g and clarification*, Order No. 1000-B, 141 FERC ¶ 61,044 (2012), *aff'd sub nom.* 762 F.3d 41, 412 (D.C. Cir. 2014); 142 FERC ¶ 61,074 (2013) (accepting the proposed PJM cost allocation method, effective February 1, 2013, subject to the outcome of PJM's Order No. 1000 regional compliance filing proceeding); 142 FERC ¶ 61,214 (2013), *order on reh'g and compliance*, 147 FERC ¶ 61,128 (2014), *order on reh'g and compliance*, 150 FERC ¶ 61,038 (2015), *order on reh'g and compliance*, 151 FERC ¶ 61,250 (2015).

45 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 3A: Energy Management System (EMS) Model Updates and Quality Assurance (QA), Rev. 13 (September 29, 2017).

46 See PJM. "Manual 3: Transmission Operations," Rev. 52 (Dec. 22, 2017), p.69.

47 *Id.* p.70.

48 The hotline tickets, EMS tripping tickets or test outage tickets were excluded. We only included all the transmission outage tickets submitted by PJM internal companies which are currently active.

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 12-34.[49]

The purpose of the rules defined in Table 12-34 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 so that PJM can accurately model market conditions.[50]

Table 12-34 PJM transmission facility outage request received status definition

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

Table 12-35 Transmission facility outage request summary by received status: planning periods 2016/2017 and 2017/2018

	2016/2017				2017/2018			
Planned Duration (Days)	On Time	Late	Total	Percent Late	On Time	Late	Total	Percent Late
<=5	8,471	7,969	16,440	48.5%	6,598	4,867	11,465	42.5%
>5 & <=30	1,667	1,781	3,448	51.7%	1,636	1,181	2,817	41.9%
>30	515	974	1,489	65.4%	554	777	1,331	58.4%
Total	10,653	10,724	21,377	50.2%	8,788	6,825	15,613	43.7%

Table 12-36 Transmission facility outage request summary by emergency: planning periods 2016/2017 and 2017/2018

	2016/2017				2017/2018			
Planned Duration (Days)	Emergency	Non Emergency	Total	Percent Emergency	Emergency	Non Emergency	Total	Percent Emergency
<=5	2,186	14,254	16,440	13.3%	1,301	10,164	11,465	11.3%
>5 & <=30	433	3,015	3,448	12.6%	254	2,563	2,817	9.0%
>30	199	1,290	1,489	13.4%	153	1,178	1,331	11.5%
Total	2,818	18,559	21,377	13.2%	1,708	13,905	15,613	10.9%

Table 12-35 shows a summary of requests by received status. In the 2017/2018 planning period, 43.7 percent of outage requests received were late. In the 2016/2017 planning period, 50.2 percent of outage requests received were late.

Once received, PJM processes outage requests in priority order: emergency transmission outage request; transmission outage requests submitted on time; and transmission outage request submitted late. PJM retains the right to deny all transmission outage requests that are submitted late unless the request is an emergency.

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.[51] Table 12-36 is a summary of outage requests by emergency status. Of all outage requests scheduled to occur in the 2017/2018 planning period, 10.9 percent were for emergency outages. Of all outage requests scheduled to occur in the 2016/2017 planning period, 13.2 percent were for emergency outages.

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."[52]

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

49 See PJM. "Manual 3: Transmission Operations," Rev. 52 (Dec. 22, 2017), at 69–70.

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

51 PJM. "Manual 3: Transmission Operations," Rev. 52 (Dec. 22, 2017) at 81.

52 PJM added this definition to Manual 38 in February 2017. PJM. "Manual 38: Operations Planning," Rev. 11 (Feb. 1, 2018) at 20.

Owner defer the outage. If no solutions are available, PJM may require the Transmission Owner to reschedule or cancel the outage.

Table 12-37 is a summary of outage requests by congestion status. Of all outage requests submitted to occur in the 2017/2018 planning period, 8.1 percent were expected to cause congestion. Of all the outage requests that were expected to cause congestion, 3.0 percent (38 out of 1,264) were denied by PJM in the 2017/2018 planning period and 16.4 percent (207 out of 1,264) were cancelled (Table 12-39). Of all outage requests submitted to occur in the 2016/2017 planning period, 8.9 percent were expected to cause congestion. Of all the outage requests that were expected to cause congestion, 4.1 percent (77 out of 1,893) were denied by PJM in the 2016/2017 planning period and 18.9 percent (357 out of 1,893) were cancelled (Table 12-39).

Table 12-37 Transmission facility outage request summary by congestion: planning periods 2016/2017 and 2017/2018

	2016/2017				2017/2018			
Planned Duration (Days)	Congestion Expected	No Congestion Expected	Total	Percent Congestion Expected	Congestion Expected	No Congestion Expected	Total	Percent Congestion Expected
<=5	1,389	15,051	16,440	8.4%	807	10,658	11,465	7.0%
>5 & <=30	373	3,075	3,448	10.8%	317	2,500	2,817	11.3%
>30	131	1,358	1,489	8.8%	140	1,191	1,331	10.5%
Total	1,893	19,484	21,377	8.9%	1,264	14,349	15,613	8.1%

Table 12-38 shows the outage requests summary by received status, congestion status and emergency status. In the 2017/2018 planning period, 32.9 percent of requests were submitted late and were nonemergency while 1.3 percent of requests (205 out of 15,613) were late, nonemergency, and expected to cause congestion. In the 2016/2017 planning period, 37.1 percent of request were submitted late and were nonemergency while 1.9 percent of requests (403 out of 21,377) were late, nonemergency, and expected to cause congestion.

Table 12-38 Transmission facility outage request summary by received status, emergency and congestion: planning periods 2016/2017 and 2017/2018

		2016/2017				2017/2018			
Received Status		Congestion Expected	No Congestion Expected	Total	Percent	Congestion Expected	No Congestion Expected	Total	Percent
Late	Emergency	114	2,687	2,801	13.1%	71	1,615	1,686	10.8%
	Non Emergency	403	7,520	7,923	37.1%	205	4,934	5,139	32.9%
On Time	Emergency	2	15	17	0.1%	3	19	22	0.1%
	Non Emergency	1,374	9,262	10,636	49.8%	985	7,781	8,766	56.1%
Total		1,893	19,484	21,377	100.0%	1,264	14,349	15,613	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.[53] Table 12-39 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 12-39. Table 12-39 shows that of all the outage requests that were expected to cause congestion, 3.0 percent (38 out of 1,264) were denied by PJM in the 2017/2018 planning period, 56.9 percent were complete and 16.4 percent (207 out of 1,264) were cancelled. Of all the outage requests that were expected to cause congestion, 4.1 percent (77 out of 1,893) were denied by PJM in the 2016/2017 planning period, 72.0 percent were complete and 18.9 percent (357 out of 1,893) were cancelled.

53 See PJM Markets & Operations, PJM Tools "Outage Information," <http://www.pjm.com/markets-and-operations/etools/oasis/system-information/outage-info.aspx> (2017).

Table 12-39 Transmission facility outage requests that might cause congestion status summary: planning periods 2016/2017 and 2017/2018

		2016/2017						2017/2018					
Submission Status		Cancelled	Complete	In Process	Denied	Congestion Expected	Percent Complete	Cancelled	Complete	In Process	Denied	Congestion Expected	Percent Complete
Late	Emergency	10	103	0	1	114	90.4%	10	59	2	0	71	83.1%
	Non Emergency	69	280	10	44	403	69.5%	29	129	32	13	205	62.9%
On Time	Emergency	0	1	0	0	2	50.0%	2	1	0	0	3	33.3%
	Non Emergency	278	979	75	32	1,374	71.3%	166	530	257	25	985	53.8%
Total		357	1,363	85	77	1,893	72.0%	207	719	291	38	1,264	56.9%

There are clear rules defined for assigning On Time or Late status for submitted outage requests in both the PJM Tariff and PJM Manuals.[54] However, the On Time or Late status only affects the priority that PJM assigns for processing the outage request. Table 12-39 shows that in the 2016/2017 planning period, many (69.5 percent or 280 out of 403) outages that were nonemergency, expected to cause congestion, and late transmission outages were approved and completed compared to (62.9 percent or 129 out of 205) in the 2017/2018 planning period. The expected impact on congestion is the basis for PJM's treatment of late outage requests. But there is no rule or clear definition of this congestion analysis in the PJM Manuals. The MMU recommends that PJM draft a clear definition of the congestion analysis required for transmission outage requests to include in Manual 3 after appropriate review.

Rescheduling Transmission Facility Outage Requests

A TO can reschedule or cancel an outage after initial submission. Table 12-40 is a summary of all the outage requests planned for the planning periods 2016/2017 and 2017/2018 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 2017/2018 planning period, 24.2 percent of transmission outage requests were approved by PJM and then rescheduled by the TOs, and 9.2 percent of the transmission outages were approved by PJM and subsequently cancelled by the TOs. In the 2016/2017 planning period, 30.2 percent of transmission outage requests were approved by PJM and then rescheduled by the TO, and 10.8 percent of the transmission outages were approved by PJM and subsequently cancelled by the TO.

Table 12-40 Rescheduled and cancelled transmission outage request summary: planning periods 2016/2017 and 2017/2018

	2016/2017					2017/2018				
Days	Outage Requests	Approved and Rescheduled	Percent Approved and Rescheduled	Approved and Cancelled	Percent Approved and Cancelled	Outage Requests	Approved and Rescheduled	Percent Approved and Rescheduled	Approved and Cancelled	Percent Approved and Cancelled
<=5	16,440	3,460	21.0%	2,048	12.5%	11,465	1,922	16.8%	1,252	10.9%
>5 & <=30	3,448	2,008	58.2%	211	6.1%	2,817	1,192	42.3%	135	4.8%
>30	1,489	990	66.5%	50	3.4%	1,331	668	50.2%	44	3.3%
Total	21,377	6,458	30.2%	2,309	10.8%	15,613	3,782	24.2%	1,431	9.2%

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.[55] This rule allows a TO to reschedule within the same month with very little notice.

54 OA Schedule 1 § 1.9.2.
55 PJM. "Manual 3: Transmission Operations," Rev. 52 (Dec. 22, 2017) at 70.

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.[56] 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 nine months prior to the month in which the outage was expected to occur.

The MMU recommends that PJM reevaluate all transmission outage tickets as On Time or Late as if they were new requests when an outage is rescheduled and apply the standard rules for late submissions to any such outages.

Long Duration Transmission Facility Outage Requests

PJM rules (Table 12-34) 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.

Table 12-41 shows that there were 10,063 transmission equipment planned outages in the 2017/2018 planning period, of which 1,374 were planned outages longer than 30 days, and of which 200 or 2.0 percent were scheduled longer than 30 days if the duration of the outages were combined for the same equipment. The duration of those outages could potentially be longer than 30 days, however were divided into shorter periods by transmission owners.

56 *Id.*

Table 12-41 Transmission outage summary: planning periods 2016/2017 and 2017/2018

		2016/2017		2017/2018	
Duration	Divided into Shorter Periods	Number of Outages	Percent	Number of Outages	Percent
> 30 Days	No	1,287	10.1%	1,174	11.7%
	Yes	247	1.9%	200	2.0%
<= 30 Days		11,238	88.0%	8,689	86.3%
Total		12,772	100.0%	10,063	100.0%

Table 12-42 shows the details of potentially long duration (> 30 days) outages when combining the duration of the outages for the same equipment. The actual duration of scheduled outages would be longer than 30 days if the duration of the outages were combined for the same equipment within a period of days. In the 2017/2018 planning period, there would have been 25 outages with a combined duration longer than 30 days that were instead scheduled to occur as shorter outages within a period of more than 31 days and less than 62 days.

Table 12-42 Summary of potentially long duration (> 30 days) outages: planning periods 2016/2017 and 2017/2018

	2016/2017		2017/2018	
Days	Number of Outages	Percent	Number of Outages	Percent
<=31	4	1.6%	4	2.0%
>31 & <=62	28	11.3%	25	12.5%
>62 & <=93	14	5.7%	20	10.0%
>93	201	81.4%	151	75.5%
Total	247	100.0%	200	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 so that 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 months and may consider outages with planned durations shorter than two months. PJM may exercise significant discretion in selecting outages to be modeled. PJM posts an FTR outage list to the FTR web page usually at least one week before the auction bidding opening day.[57]

In the 2017/2018 planning period, 250 outage requests were included in the annual FTR market outage list and 15,363 outage requests were not included. In the 2016/2017 planning period, 249 outage requests were included in the annual FTR market outage list and 21,128 outage requests were not included. Table 12-43, Table 12-44, Table 12-45 and Table 12-46 show the summary information on the modeled outage requests and Table 12-47 and Table 12-48 show the summary information on outages that were not included in the Annual FTR Market.

Table 12-43 Annual FTR market modeled transmission facility outage requests by received status: planning periods 2016/2017 and 2017/2018

	2016/2017				2017/2018			
Planned Duration	On Time	Late	Total	Percent	On Time	Late	Total	Percent
<2 weeks	10	1	11	4.4%	4	2	6	2.4%
>=2 weeks & <2 months	88	2	90	36.1%	87	9	96	38.4%
>=2 months	125	23	148	59.4%	126	22	148	59.2%
Total	223	26	249	100.0%	217	33	250	100.0%

Table 12-44 Annual FTR market modeled transmission facility outage requests by emergency and received status: planning periods 2016/2017 and 2017/2018

		2016/2017				2017/2018			
	Planned Duration	Emergency	Non Emergency	Total	Percent Non Emergency	Emergency	Non Emergency	Total	Percent Non Emergency
On Time	<2 weeks	0	10	10	100.0%	0	4	4	100.0%
	>=2 weeks & <2 months	0	88	88	100.0%	0	87	87	100.0%
	>=2 months	0	125	125	100.0%	0	126	126	100.0%
	Total	0	223	223	100.0%	0	217	217	100.0%
Late	<2 weeks	0	1	1	100.0%	0	2	2	100.0%
	>=2 weeks & <2 months	0	2	2	100.0%	0	9	9	100.0%
	>=2 months	2	21	23	91.3%	0	22	22	100.0%
	Total	2	24	26	92.3%	0	33	33	100.0%

Table 12-43 shows that 2.4 percent of the outage requests modeled in the Annual FTR Market for the 2017/2018 planning period had a planned duration of less than two weeks and that 13.2 percent of the outage requests (33 out of 250) modeled in the Annual FTR Market for the planning period were submitted late according to outage submission rules. It also shows that 4.4 percent of the outage requests modeled in the Annual FTR Market for the 2016/2017 planning period had a planned duration of less than two weeks and that 10.4 percent of the outage requests (26 out of 249) modeled in the Annual FTR Market for the planning period were submitted late according to outage submission rules.

Table 12-44 shows the annual FTR market modeled outage requests summary by emergency status and received status. All the annual FTR market modeled outages expected to occur in the 2017/2018 planning period were nonemergency outages. Two of the modeled outages expected to occur in the 2016/2017 planning period were emergency outages.

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 12-45 shows a summary of requests by expected congestion and received status. Overall, 12.1 percent (4 out of 33) of all the annual FTR market modeled outages expected to occur in the 2017/2018 planning period and submitted late were expected to cause congestion. Of all the annual FTR market modeled outages expected to occur in the 2016/2017 planning period and submitted late, 11.5 percent (3 out of 26) were expected to cause congestion.

57 PJM Financial Transmission Rights, "Annual ARR Allocation and FTR Auction Transmission Outage Modeling," <http://www.pjm.com/~/media/markets-ops/ftr/annual-ftr-auction/2017-2018/2017-2018-annual-outage-modeling.ashx> (February 21, 2017).

Table 12-45 Annual FTR market modeled transmission facility outage requests by congestion and received status: planning periods 2016/2017 and 2017/2018

		2016/2017				2017/2018			
	Planned Duration	Congestion Expected	No Congestion Expected	Total	Percent Congestion Expected	Congestion Expected	No Congestion Expected	Total	Percent Congestion Expected
On Time	<2 weeks	2	8	10	20.0%	1	3	4	25.0%
	>=2 weeks & <2 months	19	69	88	21.6%	20	67	87	23.0%
	>=2 months	29	96	125	23.2%	34	92	126	27.0%
	Total	50	173	223	22.4%	55	162	217	25.3%
Late	<2 weeks	0	1	1	0.0%	0	2	2	0.0%
	>=2 weeks & <2 months	0	2	2	0.0%	1	8	9	11.1%
	>=2 months	3	20	23	13.0%	3	19	22	13.6%
	Total	3	23	26	11.5%	4	29	33	12.1%

Table 12-46 shows that 27.1 percent of outage requests modeled in the annual FTR market for the 2017/2018 planning period and with a duration of two weeks or longer but shorter than two months were cancelled, compared to 35.6 percent for the 2016/2017 planning period. Table 12-46 also shows that 10.8 percent of outages requests modeled in the Annual FTR Market for the 2017/2018 planning period and with a duration of two months or longer were cancelled, compared to 20.9 percent for the 2016/2017 planning period.

Table 12-46 Annual FTR market modeled transmission facility outage requests by processed status: planning periods 2016/2017 and 2017/2018

		2016/2017		2017/2018	
Planned Duration	Processed Status	Outage Requests	Percent	Outage Requests	Percent
<2 weeks	In Progress	0	0.0%	1	16.7%
	Denied	0	0.0%	0	0.0%
	Approved	0	0.0%	0	0.0%
	Cancelled	1	9.1%	2	33.3%
	Revised	0	0.0%	0	0.0%
	Active	0	0.0%	0	0.0%
	Completed	10	90.9%	3	50.0%
	Total	11	100.0%	6	100.0%
>=2 weeks & <2 months	In Progress	10	11.1%	31	32.3%
	Denied	0	0.0%	2	2.1%
	Approved	0	0.0%	0	0.0%
	Cancelled	32	35.6%	26	27.1%
	Revised	0	0.0%	2	2.1%
	Active	0	0.0%	1	1.0%
	Completed	48	53.3%	34	35.4%
	Total	90	100.0%	96	100.0%
>=2 months	In Progress	23	15.5%	49	33.1%
	Denied	0	0.0%	0	0.0%
	Approved	0	0.0%	1	0.7%
	Cancelled	31	20.9%	16	10.8%
	Revised	0	0.0%	2	1.4%
	Active	3	2.0%	31	20.9%
	Completed	91	61.5%	49	33.1%
	Total	148	100.0%	148	100.0%

More outage requests were not modeled in the Annual FTR Market than were modeled in the Annual FTR Market. In the 2017/2018 planning period, 250 outage requests were modeled and 15,363 outage requests were not modeled in the Annual FTR Market. In the 2016/2017 planning period, 249 outage requests were modeled and 21,128 outage requests were not modeled in the Annual FTR Market.

Table 12-47 shows that 12.3 percent of outage requests not modeled in the Annual FTR Auction with duration longer than or equal to two months, labelled On Time according to the rules, were submitted after the Annual FTR Auction bidding opening date for the 2017/2018 planning period compared to 17.5 percent in the 2016/2017 planning period.

Table 12-47 Transmission facility outage requests not modeled in Annual FTR Auction: planning periods 2016/2017 and 2017/2018

	2016/2017						2017/2018					
	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	1,486	7,988	84.3%	261	8,802	97.1%	1,405	6,056	81.2%	231	5,306	95.8%
>=2 weeks & <2 months	460	376	45.0%	152	953	86.2%	603	352	36.9%	107	715	87.0%
>=2 months	99	21	17.5%	185	345	65.1%	136	19	12.3%	197	236	54.5%
Total	2,045	8,385	80.4%	598	10,100	94.4%	2,144	6,427	75.0%	535	6,257	92.1%

Table 12-48 shows that 42.8 percent of late outage requests which were not modeled in the Annual FTR Auction with duration longer than or equal to two months and submitted after the Annual FTR Auction bidding opening date were approved and completed in the 2017/2018 planning period. It also shows that 78.0 percent of late outage requests which were not modeled in the Annual FTR Auction with duration longer than or equal to two months and submitted after the Annual FTR Auction bidding opening date were approved and completed in the 2016/2017 planning period.

Table 12-48 Late transmission facility outage requests not modeled in Annual FTR Auction and submitted after annual bidding opening date: planning periods 2016/2017 and 2017/2018

	2016/2017			2017/2018		
Planned Duration	Completed Outages	Total	Percent	Completed Outages	Total	Percent
<2 weeks	7,385	8,802	83.9%	4,128	5,306	77.8%
>=2 weeks & <2 months	834	953	87.5%	485	715	67.8%
>=2 months	269	345	78.0%	101	236	42.8%
Total	8,488	10,100	84.0%	4,714	6,257	75.3%

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 long duration transmission outages from being submitted late. The MMU recommends that PJM modify the rules to eliminate the approval of outage requests submitted or rescheduled after the opening of bidding in the Annual FTR Auction.

Monthly FTR Market

When determining transmission outages to be modeled in the simultaneous feasibility test used 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 shorter than or equal to five days. PJM may exercise 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.[58] Table 12-49 and Table 12-50 show the summary information on outage requests modeled in the Monthly Balance of Planning Period FTR Auction and Table 12-51 and Table 12-52 show the summary information on outage requests not modeled in the Monthly Balance of Planning Period FTR Auction.

Table 12-49 shows that on average, 29.3 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 2017/2018

58 PJM Financial Transmission Rights, "2015/2016 Monthly FTR Auction Transmission Outage Modeling," <http://www.pjm.com/-/media/markets-ops/ftr/ftr-allocation/monthly-ftr-auctions/2015-2016-monthly-transmission-outages-that-may-cause-infeasibilities.ashx?la=en> (December 9, 2015).

planning period. On average, 30.8 percent of the outage requests modeled in the Monthly Balance of Planning Period FTR Auction were submitted late according to outage submission rules in the 2016/2017 planning period.

Table 12-49 Monthly Balance of Planning Period FTR Auction modeled transmission facility outage requests by received status: planning periods 2016/2017 and 2017/2018

	2016/2017				2017/2018			
Month	On Time	Late	Total	Late Percent	On Time	Late	Total	Late Percent
Jun	170	94	264	35.6%	134	116	250	46.4%
Jul	67	57	124	46.0%	83	72	155	46.5%
Aug	77	63	140	45.0%	100	73	173	42.2%
Sep	367	129	496	26.0%	394	125	519	24.1%
Oct	542	195	737	26.5%	598	162	760	21.3%
Nov	365	172	537	32.0%	453	177	630	28.1%
Dec	289	130	419	31.0%	330	142	472	30.1%
Jan	162	90	252	35.7%				
Feb	162	89	251	35.5%				
Mar	310	132	442	29.9%				
Apr	395	162	557	29.1%				
May	411	165	576	28.6%				
Avg	276	123	400	30.8%	299	124	423	29.3%

Table 12-50 shows that on average, 18.6 percent of outage requests modeled in the Monthly Balance of Planning Period FTR Auction were cancelled in the 2017/2018 planning period. On average, 20.4 percent of outage requests modeled in the Monthly Balance of Planning Period FTR Auction were cancelled in the 2016/2017 planning period.

Table 12-50 Monthly Balance of Planning Period FTR Auction modeled transmission facility outage requests by processed status: planning periods 2016/2017 and 2017/2018

Planning Year	Month	In Process	Denied	Approved	Cancelled	Revised	Active	Complete	Total	Cancelled Percent
2016/2017	Jun	18	3	5	51	1	53	133	264	19.3%
	Jul	10	12	2	19	0	41	40	124	15.3%
	Aug	9	1	2	31	0	52	45	140	22.1%
	Sep	47	4	11	85	0	165	184	496	17.1%
	Oct	75	5	19	172	0	196	270	737	23.3%
	Nov	46	1	10	104	0	162	214	537	19.4%
	Dec	25	4	11	87	0	66	226	419	20.8%
	Jan	35	0	7	60	0	75	75	252	23.8%
	Feb	22	2	4	42	1	87	93	251	16.7%
	Mar	48	2	9	94	0	120	169	442	21.3%
	Apr	55	2	7	101	1	154	237	557	18.1%
	May	26	1	18	134	0	119	278	576	23.3%
	Avg	35	3	9	82	0	108	164	400	20.4%
2017/2018	Jun	19	5	5	52	0	64	105	250	20.8%
	Jul	11	2	8	25	0	54	55	155	16.1%
	Aug	10	0	1	27	0	64	71	173	15.6%
	Sep	67	8	13	100	3	161	167	519	19.3%
	Oct	77	2	27	142	0	201	311	760	18.7%
	Nov	39	5	10	121	2	177	276	630	19.2%
	Dec	42	4	9	97	0	74	246	472	20.6%
	Avg	38	4	10	81	1	114	176	423	18.6%

Table 12-51 shows that on average, 8.9 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 2017/2018 planning period, compared to 10.1 percent in the 2016/2017 planning period. On average, 71.0 percent of outage requests not modeled in the Monthly Balance of Planning Period FTR Auction, labeled Late according to the rules, were submitted after the Monthly Balance of Planning Period FTR Auction bidding opening dates in the 2017/2018 planning period, compared to 70.7 percent in the 2016/2017 planning period.

Table 12-51 Transmission facility outage requests that are not modeled in Monthly Balance of Planning Period FTR Auction: planning periods 2016/2017 and 2017/2018

	2016/2017						2017/2018					
	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	694	103	12.9%	336	894	72.7%	642	96	13.0%	306	851	73.6%
Jul	274	74	21.3%	251	698	73.6%	294	48	14.0%	245	608	71.3%
Aug	413	92	18.2%	259	733	73.9%	344	25	6.8%	211	651	75.5%
Sep	964	156	13.9%	292	772	72.6%	862	81	8.6%	257	598	69.9%
Oct	1,092	89	7.5%	430	901	67.7%	1,000	75	7.0%	347	866	71.4%
Nov	887	57	6.0%	389	832	68.1%	829	69	7.7%	367	789	68.3%
Dec	601	47	7.3%	340	723	68.0%	623	55	8.1%	330	687	67.6%
Jan	432	35	7.5%	243	592	70.9%						
Feb	462	25	5.1%	301	674	69.1%						
Mar	1,068	94	8.1%	357	806	69.3%						
Apr	1,140	103	8.3%	340	789	69.9%						
May	1,143	154	11.9%	356	966	73.1%						
Avg	764	86	10.1%	325	782	70.7%	656	64	8.9%	295	721	71.0%

Table 12-52 shows that on average, 69.5 percent of late outage requests which were not modeled in the Monthly Balance of Planning Period FTR Auction, submitted after the Monthly Balance of Planning Period FTR Auction bidding opening dates, were approved and complete in the 2017/2018 planning period, compared to 69.5 percent in the 2016/2017 planning period.

Table 12-52 Late transmission facility outage requests that are not modeled in Monthly Balance of Planning Period FTR Auction and submitted after monthly bidding opening date: planning periods 2016/2017 and 2017/2018

	2016/2017			2017/2018		
	Completed Outages	Total	Percent	Completed Outages	Total	Percent
Jun	639	894	71.5%	627	851	73.7%
Jul	476	698	68.2%	410	608	67.4%
Aug	523	733	71.4%	473	651	72.7%
Sep	495	772	64.1%	406	598	67.9%
Oct	644	901	71.5%	595	866	68.7%
Nov	536	832	64.4%	490	789	62.1%
Dec	534	723	73.9%	508	687	73.9%
Jan	401	592	67.7%			
Feb	447	674	66.3%			
Mar	580	806	72.0%			
Apr	575	789	72.9%			
May	668	966	69.2%			
Avg	543	782	69.5%	501	721	69.5%

Transmission Facility Outage Analysis in the Day-Ahead Energy Market

Transmission facility outages also affect the energy market. Just as with the FTR Market, it is critical that outages that affect the operating day are known prior to the submission of offers in the Day-Ahead Energy Market so that market participants can understand market conditions and so that 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. [59]

In order to analyze the market impact, the outage requests that affect the operating day are compared: 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 the view of outages available

59 PJM. "Manual 3: Transmission Operations," Rev. 52 (Dec. 22, 2017) at 74

to market participants. The day-ahead market model uses a list of outages as an input. The list of 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 impact on markets.

For example for the operating day of November 23, 2016, Figure 12-4 shows that: there were 421 approved or active outages seen by market participants before the day-ahead market was closed; there were 282 outage requests included in the day-ahead market model; there were 273 outage request included in both sets of outage; there were 148 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 nine outage requests included in day-ahead market model but not available to market participants prior to the day-ahead market.

Figure 12-4 Illustration of day-ahead market analysis: November 22, 2016

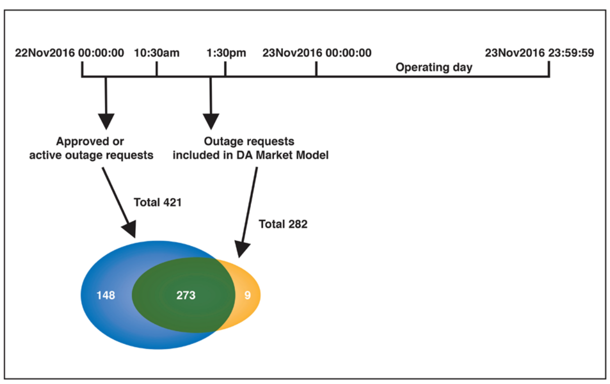


Figure 12-5 compares the weekly average number of active or approved outages available to market participants prior to the close of the day-ahead market with the outages included as inputs to the day-ahead market by PJM.

Figure 12-5 Approved or active outage requests: 2015 through 2017

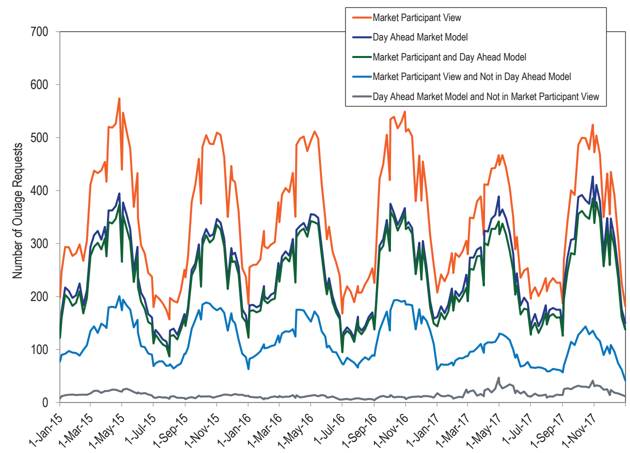


Figure 12-6 compares the weekly average number of outages included as inputs to the day-ahead market by PJM with the outages that actually occurred during the operating day.

Figure 12-6 Day-ahead market model outages: 2015 through 2017

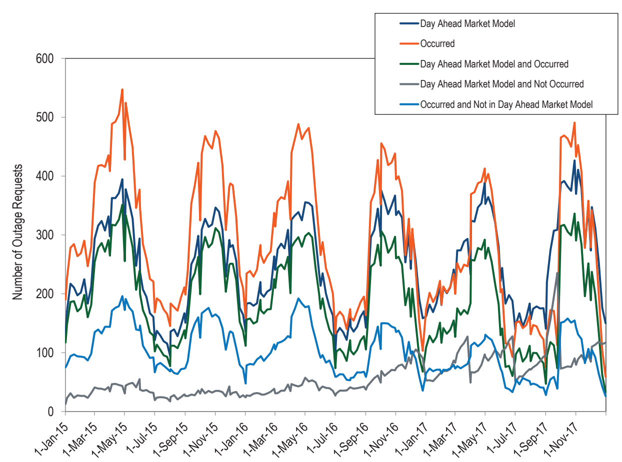


Figure 12-7 compares the weekly average number of active or approved outages available to market participants prior to the close of the day-ahead market with the outages that actually occurred during the operating day.

Figure 12-7 Approved or active outage requests: 2015 through 2017

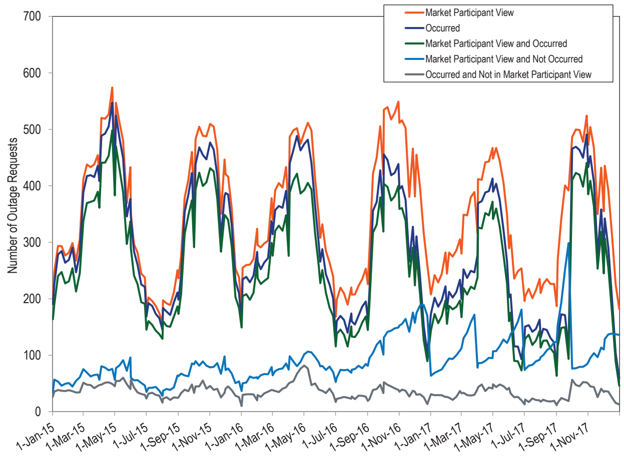


Figure 12-5, Figure 12-6, and Figure 12-7 show that on a weekly average basis, the active or approved outages available to day-ahead market participants, the outages included as inputs in the day-ahead market model and the outages that actually occurred in real time are not consistent. The active or approved outages available to day-ahead market participants are more consistent with the outages that actually occurred in real time than with the outages included in the day-ahead market model.