Generation and Transmission Planning[1]

Overview

Planned Generation and Retirements

- **Planned Generation.** As of September 30, 2017, 95,508.9 MW of capacity were in generation request queues for construction through 2024, compared to an average installed capacity of 201,573.5 MW as of September 30, 2017. Of the capacity in queues, 8,900.7 MW, or 9.3 percent, are uprates and the rest are new generation. Wind projects account for 15,580.9 MW of nameplate capacity or 16.3 percent of the capacity in the queues. Natural gas fired projects account for 59,943.8 MW of capacity or 62.8 percent of the capacity in the queues.

- **Generation Retirements.** As shown in Table 12-5, 32,150.7 MW have been, or are planned to be, retired between 2011 and 2020. Of that, 6,427.3 MW are planned to retire after September 30, 2017. In the first nine months of 2017, 2,072.8 MW were retired. Of the 6,427.3 MW pending retirement, 4,125.0 MW (64.2 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 59,943.8 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.

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

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, 3,590 projects, representing 465,477.1 MW, have entered the queue process since its inception. Of those, 734 projects, representing 49,788.4 MW, went into service. Of the projects that entered the queue process, 56.9 percent of the MW withdrew prior to completion. Such projects may create barriers to entry for projects that would otherwise be completed by taking up queue positions, increasing interconnection costs and creating uncertainty.

- 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]

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).

- 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 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)

- 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 to LS Power, a merchant developer, PSEG, and PHI with a total cost estimate between $263M and $283M.[7] [8] 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.[9]
- The TEAC regularly reviews internal and external proposals to improve transmission reliability throughout PJM. 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.[10]

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

6 See OATT § 1 (Transmission Owner).
7 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>.
8 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>.
9 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).
10 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).

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.[11]

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.[12]
- There were 10,186 transmission outage requests submitted in the 2017/2018 planning period. Of the requested outages, 69.4 percent were planned for five days or shorter and 9.5 percent were planned for longer than 30 days. Of the requested outages, 38.3 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 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.[13] (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.)

11 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> Accessed October 5, 2017.
12 PJM. "Manual 03: Transmission Operations," Rev. 51 (June 1, 2017), Section 4.
13 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>.

- 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 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.)

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 September 30, 2017, 95,508.9 MW of capacity were in generation request queues for construction through 2024, compared to an average installed capacity of 201,573.5 MW as of September 30, 2017. Although it is clear that not all generation in the queues will be built, PJM has added capacity.[14] In the first nine months of 2017, 3,352.4 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

14 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>.

queue.[15] 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.[16]

Table 12-1 shows MW in queues by expected completion date and MW changes in the queues between December 31, 2016, and September 30, 2017, for ongoing projects, i.e. projects with the status active, under construction or suspended.[17] Projects that are already in service are not included here. The total MW in queues increased by 13,572.6 MW, or 16.6 percent, from 81,936.3 MW at the end of 2016 to 95,508.9 MW on September 30, 2017.

Table 12-1 Queue comparison by expected completion year (MW): December 31, 2016 to September 30, 2017[18]

			Nine Month Change	
Year	As of 12/31/2016	As of 9/30/2017	MW	Percent
2016	21,064.0	0.0	(21,064.0)	(100.0%)
2017	12,957.0	12,887.3	(69.7)	(0.5%)
2018	14,859.6	23,560.5	8,700.9	58.6%
2019	18,416.5	25,720.8	7,304.3	39.7%
2020	10,869.3	20,763.7	9,894.4	91.0%
2021	1,925.9	9,485.7	7,559.8	392.5%
2022	250.0	3,090.9	2,840.9	1,136.4%
2023	0.0	0.0	0.0	0.0%
2024	1,594.0	0.0	(1,594.0)	(100.0%)
Total	81,936.3	95,508.9	13,572.6	16.6%

Table 12-2 shows the project status changes in more detail and how scheduled queue capacity has changed between December 31, 2016, and September 30, 2017. For example, 19,639.2 MW entered the queue between January 1, 2017 and September 30, 2017. Of those 19,639.2 MW, 7,190.3 MW have been withdrawn. Of the total 63,728.9 MW marked as active at the beginning of 2017, 6,212.6 MW were withdrawn, 1,955.0 MW were suspended, 1,828.0 MW started construction, and 234.1 MW went into service by September 30, 2017. The Under Construction column shows that 791.4 MW came out of suspension and 1,828.0 MW began construction in the first nine months of 2017, in addition to the 17,584.5 MW of capacity that maintained the status under construction from December 31, 2016 through September 30, 2017.

Table 12-2 Change in project status (MW): December 31, 2016 to September 30, 2017

		Status at 9/30/2017				
Status at 12/31/2016	Total at 12/31/2016	Active	Suspended	Under Construction	In Service	Withdrawn
(Entered during 2017)		12,448.9	0.0	0.0	0.0	7,190.3
Active	63,728.9	53,499.2	1,955.0	1,828.0	234.1	6,212.6
Suspended	5,790.0	0.0	4,356.5	791.4	0.0	642.2
Under Construction	24,014.4	108.9	2,936.7	17,584.5	3,150.3	234.1
In Service	46,404.0	0.0	0.0	0.0	46,404.0	0.0
Withdrawn	305,900.6	0.0	0.0	0.0	0.0	305,900.6
Total	445,837.9	66,056.9	9,248.2	20,203.9	49,788.4	320,179.8

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 September 30, 2017, there are 95,508.9 MW of capacity in queues that are not yet in service, of which 9.7 percent are suspended, 21.2 percent are under construction and 69.2 percent have not begun construction.

15 See PJM. "Manual 14C: Generation and Transmission Interconnection Process," Rev. 12 (June 22, 2017) Section 3.7.
16 PJM does not track the duration of suspensions or PJM termination of projects.
17 Expected completion dates are entered when the project enters the queue. Actual completion dates are generally different than expected completion dates.
18 Wind and solar capacity in Table 12-1 through Table 12-4 have not been adjusted to reflect derating.

Table 12-3 Capacity in PJM queues (MW): September 30, 2017[19]

Queue	Active	In Service	Under Construction	Suspended	Withdrawn	Total
A Expired 31-Jan-98	0.0	8,103.0	0.0	0.0	17,252.0	25,355.0
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	40.0	0.0	0.0	846.0	886.0
K Expired 31-Jul-03	0.0	98.9	0.0	0.0	485.3	584.2
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	1,288.3	19,420.6	22,755.3
S Expired 31-Jul-07	0.0	3,549.5	120.0	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	292.0	2,138.5	875.8	989.8	19,759.2	24,055.3
X Expired 31-Jan-12	1,689.0	4,598.2	3,268.9	2,289.5	18,498.8	30,344.5
Y Expired 30-Apr-13	814.5	1,661.1	3,808.6	267.2	19,188.2	25,739.5
Z Expired 30-Apr-14	997.0	677.4	5,580.4	135.1	6,910.8	14,300.7
AA1 Expired 31-Oct-14	3,448.4	156.7	2,224.0	396.1	5,773.5	11,998.7
AA2 Expired 30-Apr-15	5,639.0	220.9	796.4	1,730.1	7,679.9	16,066.3
AB1 Expired 31-Oct-15	11,992.9	64.0	715.9	121.4	7,549.4	20,443.6
AB2 Expired 31-Mar-16	10,930.2	10.0	131.8	45.2	4,147.3	15,264.5
AC1 Through 30-Sep-16	16,883.7	1.1	0.0	34.5	3,169.1	20,088.5
AC2 Through 30-Apr-17	7,877.1	0.0	0.0	0.0	4,547.6	12,424.7
AD1 Through 30-Sep-17	4,903.1	0.0	0.0	0.0	64.8	4,967.9
Total	66,056.9	49,788.4	20,203.9	9,248.2	320,179.8	465,477.1

19 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.[20] As of September 30, 2017, 95,508.9 MW of capacity were in generation request queues for construction through 2024, compared to 93,533.3 MW at December 31, 2016.[21] Table 12-4 also shows the planned retirements for each zone.

Table 12-4 Queue capacity by LDA, control zone and fuel (MW): September 30, 2017[22]

LDA	Zone	Biomass	CC	CT	Diesel	Fuel Cell	Hydro	Nuclear	Solar	Steam	Storage	Wind	Total Queue Capacity	Planned Retirements
EMAAC	AECO	0.0	1,674.6	462.0	0.0	1.9	0.0	0.0	75.3	0.0	20.0	25.0	2,258.8	303.0
	DPL	4.0	802.0	0.0	13.6	0.0	0.0	0.0	1,431.2	0.0	25.0	649.6	2,925.4	0.0
	JCPL	0.0	1,767.1	0.0	0.0	0.4	0.0	0.0	201.8	0.0	85.0	0.0	2,054.3	614.5
	PECO	0.0	1,221.0	0.0	4.5	0.0	0.0	94.0	18.0	0.0	0.0	0.0	1,337.5	50.8
	PSEG	0.0	2,566.5	677.0	5.0	3.6	0.0	0.0	79.1	24.0	0.0	0.0	3,355.2	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
	EMAAC Total	4.0	8,031.2	1,139.0	23.1	5.9	0.0	94.0	1,805.4	24.0	130.0	674.6	11,931.2	1,579.3
SWMAAC	BGE	0.0	0.0	0.0	0.0	1.3	0.0	0.4	30.3	22.0	0.0	0.1	0.0	135.0
	Pepco	0.0	0.0	1,857.6	0.0	0.0	0.0	0.0	0.0	62.5	0.0	0.0	0.0	0.0
	SWMAAC Total	0.0	0.0	1,857.6	0.0	1.3	0.0	0.4	30.3	84.5	0.0	0.1	1,974.2	135.0
WMAAC	Met-Ed	0.0	485.0	34.1	0.0	0.0	0.0	0.0	158.0	30.0	0.0	0.0	707.1	805.0
	PENELEC	0.0	1,170.0	521.1	121.1	0.0	17.0	0.0	63.5	590.0	0.0	458.8	2,941.5	0.0
	PPL	16.0	5,818.0	19.9	19.9	0.0	0.0	0.0	30.0	0.0	30.0	441.1	6,374.9	0.0
	WMAAC Total	16.0	7,473.0	575.1	141.0	0.0	17.0	0.0	251.5	620.0	30.0	899.8	10,023.4	805.0
Non-MAAC	AEP	0.0	10,156.0	394.0	15.2	0.0	46.5	28.0	4,274.8	149.0	90.0	7,387.0	22,540.5	0.0
	APS	0.0	5,805.1	30.0	99.6	0.0	15.0	0.0	669.6	10.0	37.8	1,010.7	7,677.8	0.0
	ATSI	0.0	5,191.0	0.0	0.9	0.0	0.0	0.0	426.0	0.0	0.0	815.7	6,433.5	776.0
	ComEd	0.0	8,270.2	1,127.0	18.8	0.0	22.7	0.0	495.0	64.0	85.5	3,445.5	13,528.7	0.0
	DAY	0.0	1,150.0	0.0	0.0	0.0	0.0	0.0	762.9	12.0	39.9	300.0	2,264.8	2,404.0
	DEOK	0.0	513.0	0.0	0.0	0.0	0.0	0.0	290.0	20.0	19.8	0.0	842.8	0.0
	DLCO	0.0	205.0	0.0	0.0	0.0	0.0	0.0	11.7	0.0	20.0	0.0	236.7	0.0
	Dominion	62.5	6,879.7	155.0	8.0	0.0	5.6	0.0	9,709.1	14.0	34.0	1,047.5	17,915.5	728.0
	EKPC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	100.0	0.0	0.0	0.0	100.0	0.0
	RMU	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	38,170.0	1,706.0	142.4	0.0	89.8	28.0	16,779.1	269.0	327.0	14,006.4	71,580.2	3,908.0
Total in PJM	Total	82.5	53,674.2	5,277.7	306.5	7.2	106.8	122.4	18,866.3	997.5	487.0	15,580.9	95,508.9	6,427.3

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 September 30, 2017, there were 15,954.2 MW of gas fired capacity under construction in PJM. As of September 30, 2017, there were only 108.0 MW of coal fired steam capacity under construction in PJM. With respect to retirements, 4,125.0 MW of coal fired steam capacity and 661.8 MW of natural gas capacity are slated for deactivation between September 30, 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, 32,150.7 MW have been, or are planned to be, retired between 2011 and 2020.[23] Of that, 6,427.3 MW are planned to retire after the first nine months of 2017. In the first nine months of 2017, 2,072.8 MW were retired. Of the 6,427.3 MW pending retirement, 4,125.0 MW are coal units. The coal unit

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

21 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 namplate 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 15,580.9 MW of wind resources and 18,866.3 MW of solar resources, the 95,508.9 MW currently active in the queue would be reduced to 70,256.5 MW.

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

23 See PJM "Generator Deactivation Summary Sheets," at <http://www.pjm.com/planning/generation-deactivation/gd-summaries.aspx> (October 4, 2017).

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.

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 (Jan-Sep)	0.0	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	2,072.8
Planned Retirements (Oct 2017 and later)	40.0	4,125.0	2.4	148.0	0.0	0.0	0.0	30.6	661.8	1,419.5	0.0	0.0	0.0	6,427.3
Total	40.0	24,719.6	106.3	314.0	0.5	828.2	35.0	1,384.9	3,237.3	1,419.5	31.0	10.4	24.0	32,150.7

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

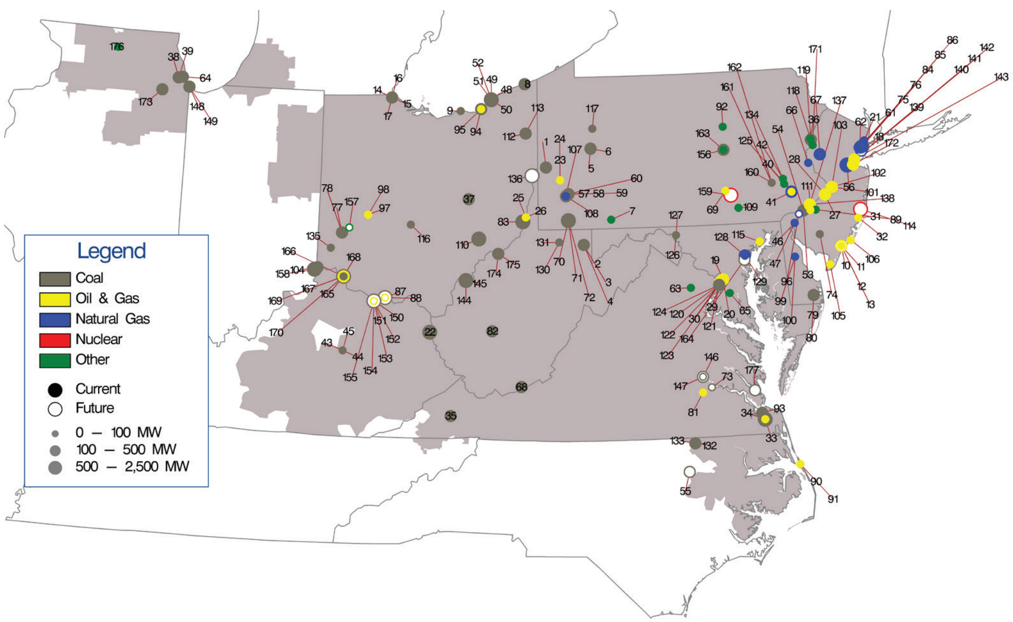


Table 12-6 Unit identification for map of PJM unit retirements: 2011 through 2020

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

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

Table 12-7 Planned retirement of PJM units: September 30, 2017[24]

Unit	Zone	ICAP (MW)	Fuel	Unit Type	Projected Deactivation Date
Yorktown 1-2	Dominion	323.0	Coal	Steam	13-Dec-17
Tait Battery	DAY	40.0	Battery	Battery	31-Dec-17
Hopewell James River Cogeneration	Dominion	89.0	Coal	Steam	31-May-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
BL England 3	AECO	148.0	Heavy Oil	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
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
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		6,427.3			

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, 76.9 percent, of all MW retiring during this period are coal fired steam units. These coal fired steam units have an average age of 54.4 years and an average size of 172.9 MW. Over half of the retiring coal fired steam units, 55.7 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.

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	1	40.0	4.3	40.0	0.1%
Coal	143	172.9	54.4	24,719.6	76.9%
Diesel	5	21.3	39.8	106.3	0.3%
Heavy Oil	2	157.0	49.5	314.0	1.0%
Hydro	1	0.5	113.8	0.5	0.0%
Kerosene	20	41.4	45.5	828.2	2.6%
Landfill Gas	9	3.9	14.0	35.0	0.1%
Light Oil	30	46.2	43.2	1,384.9	4.3%
Natural Gas	55	58.9	47.3	3,237.3	10.1%
Nuclear	2	709.8	47.8	1,419.5	4.4%
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	272	118.2	48.9	32,150.7	100.0%

24 Units designated as external installed capacity have been removed

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	6.4	0.0	0.0	0.0	0.0	0.0	0.0	1,630.4
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	250.0	51.0	0.0	0.0	0.0	0.8	0.0	189.0	0.0	0.0	0.0	0.0	490.8
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	4,517.0	0.0	166.0	0.0	0.0	16.0	49.7	333.8	805.0	31.0	10.4	24.0	5,952.9
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	0.0	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	2,641.0
Total	40.0	24,719.6	106.3	314.0	0.5	828.2	35.0	1,384.9	3,237.3	1,419.5	31.0	10.4	24.0	32,150.7

Generation Deactivations in 2017

Table 12-10 shows the units that were deactivated in the first nine months of 2017.

Table 12-10 Unit deactivations in January 1 through September 30, 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
Total		2,072.8				

Existing Generation Mix

As of September 30, 2017, PJM had an installed capacity of 201,573.5 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: September 30, 2017 (By zone and unit type (MW))[25]

ZONE	CC	CT	Diesel	Fuel Cell	Hydro	Nuclear	Solar	Steam	Storage	Wind	Total
AECO	901.9	570.7	14.6	0.0	0.0	0.0	59.4	815.9	0.0	7.5	2,370.0
AEP	6,800.0	3,682.2	80.3	0.0	1,071.9	2,071.0	14.7	18,897.8	6.0	2,254.0	34,877.9
APS	1,749.0	1,560.9	47.9	0.0	129.2	0.0	46.1	5,409.0	78.9	1,191.5	10,212.5
ATSI	1,570.5	1,618.3	63.7	0.0	0.0	2,134.0	0.0	5,719.0	0.0	0.0	11,105.5
BGE	0.0	936.6	22.4	0.0	0.4	1,716.0	1.1	2,921.5	0.0	0.0	5,598.0
ComEd	3,146.1	7,244.0	109.1	0.0	0.0	10,473.5	9.0	5,166.1	127.6	3,081.9	29,357.3
DAY	0.0	1,368.5	47.5	0.0	0.0	0.0	1.1	2,908.0	40.0	0.0	4,365.1
DEOK	47.2	654.0	4.8	0.0	112.0	0.0	0.0	3,981.0	20.0	0.0	4,819.0
DLCO	244.0	15.0	0.0	0.0	6.3	1,777.0	0.0	660.0	0.0	0.0	2,702.3
Dominion	8,371.6	4,092.7	171.8	0.0	3,589.3	3,581.3	217.8	7,566.0	0.0	208.0	27,798.5
DPL	2,498.5	1,820.4	162.1	30.0	0.0	0.0	118.4	1,586.0	0.0	0.0	6,215.4
EKPC	0.0	774.0	0.0	0.0	70.0	0.0	0.0	1,687.0	0.0	0.0	2,531.0
JCPL	2,682.5	763.1	16.1	0.0	400.0	614.5	260.6	15.0	0.0	0.0	4,751.8
Met-Ed	2,630.8	401.7	33.4	0.0	19.5	805.0	0.0	200.0	0.0	0.0	4,090.4
PECO	3,209.0	834.0	2.9	0.0	3,284.0	4,546.8	3.0	979.1	1.0	0.0	12,859.8
PENELEC	850.0	407.5	150.0	0.0	590.8	0.0	0.0	6,799.5	28.4	958.8	9,785.0
Pepco	1,827.0	1,204.7	11.9	0.0	0.0	0.0	0.0	3,649.1	0.0	0.0	6,692.7
PPL	2,657.9	602.5	55.5	0.0	706.6	2,520.0	15.0	5,169.9	20.0	219.7	11,967.1
PSEG	4,000.3	1,134.0	11.1	0.0	5.0	3,493.0	182.7	644.1	4.0	0.0	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
Total	43,186.3	29,684.8	1,005.1	30.0	9,985.0	33,732.1	928.9	74,774.0	325.9	7,921.4	201,573.5

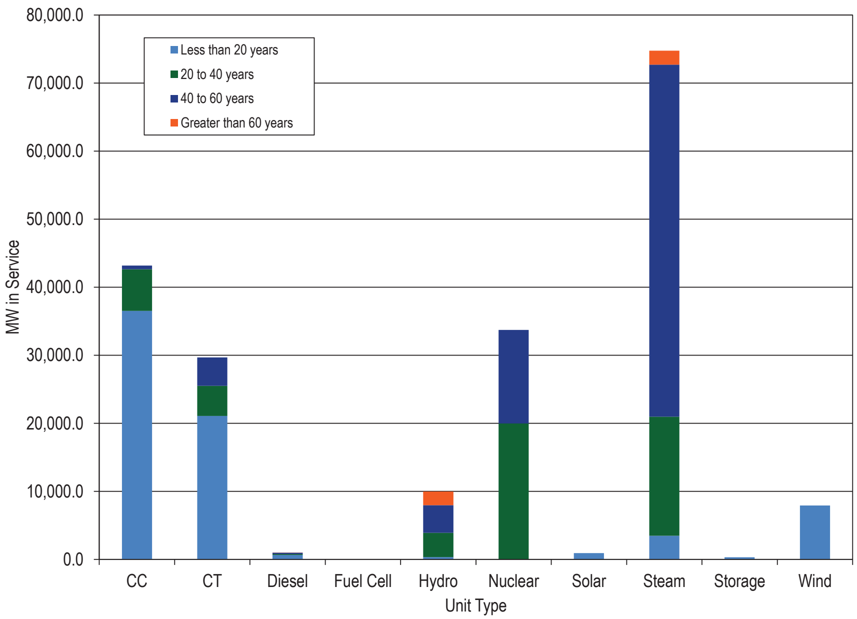
Figure 12-2 and Table 12-12 show the age of PJM generators by unit type. Units older than 40 years comprise 78,553.0 MW, or 39.0 percent, of the total capacity of 201,573.5 MW.

Table 12-12 PJM capacity (MW) by age (years): September 30, 2017

Age (years)	CC	CT	Diesel	Fuel Cell	Hydro	Nuclear	Solar	Steam	Storage	Wind	Total
Less than 20	36,530.8	21,078.8	667.6	30.0	339.7	0.0	928.9	3,487.4	325.9	7,921.4	71,310.4
20 to 40	6,123.5	4,435.4	117.9	0.0	3,563.2	19,977.9	0.0	17,492.1	0.0	0.0	51,710.0
40 to 60	532.0	4,170.6	215.6	0.0	4,063.0	13,754.2	0.0	51,723.5	0.0	0.0	74,458.9
Greater than 60	0.0	0.0	4.0	0.0	2,019.1	0.0	0.0	2,071.0	0.0	0.0	4,094.1
Total	43,186.3	29,684.8	1,005.1	30.0	9,985.0	33,732.1	928.9	74,774.0	325.9	7,921.4	201,573.5

25 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.

Figure 12-2 PJM capacity (MW) by age (years): September 30, 2017



Generation and Transmission Interconnection Planning Process

PJM made changes to the queue process in May 2012.[26] 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.[27] The Earlier Queue Submittal Task Force (EQSTF) was established in August 2015, to further address the issue.[28]

26 See PJM Interconnection, L.L.C., Docket No. ER12-1177 (Feb. 29, 2012).
27 See "PJM Interconnection Queue Status & Statistics Update Database Snapshot on 05/27/2015," presented by Dave Egan to the PJM Planning Committee (June 11, 2015)
28 See Earlier Queue Submittal Task Force at <http://www.pjm.com/committees-and-groups/closed-groups/eqstf.aspx>.

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.[29]

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.

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.[30] 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, 52.3 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.[31] [32] Withdrawing at or beyond this point is uncommon; only 251 projects, or 12.3 percent, of all projects withdrawn were withdrawn after reaching this milestone.

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

30 See PJM. "Manual 14B. PJM Region Transmission Planning Process," Rev. 38 (July 27, 2017), p.80.

31 "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," Rev. 12 (June 22, 2017).

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

Table 12-14 Last milestone at time of withdrawal: January 1, 1997 through September 30, 2017

Milestone Completed	Projects Withdrawn	Percent	Average Days	Maximum Days
Never Started	244	11.9%	165	1,235
Feasibility Study	826	40.4%	341	3,238
System Impact Study	461	22.5%	606	3,174
Facilities Study	263	12.9%	1,335	4,210
Construction Service Agreement (CSA) or beyond	251	12.3%	1,498	4,249
Total	2,045	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 996 days, or 2.7 years, between entering a queue and going into service. For withdrawn projects, there is an average time of 649 days, or 1.8 years, between entering a queue and withdrawing.

Table 12-15 Average project queue times (days): September 30, 2017

Status	Average (Days)	Standard Deviation	Minimum	Maximum
Active	928	532	21	3,745
In-Service	996	713	1	4,024
Suspended	2,123	1,203	705	5,185
Under Construction	1,823	1,028	378	4,977
Withdrawn	649	680	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 811 projects in the queue as of September 30, 2017, 68 had a completed feasibility study and 142 were under construction.

Table 12-16 PJM generation planning summary: September 30, 2017

Milestone Reached	Number of Projects	Percent of Total Projects	Average Days	Maximum Days
Under Review	414	51.0%	818	2,039
Feasibility Study	68	8.4%	1,089	1,972
System Impact Study	116	14.3%	998	3,099
Facilities Study	71	8.8%	2,104	4,260
Construction Service Agreement (CSA) or beyond	142	17.5%	2,282	5,185
Total	811	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 895 projects entered in 2014, 2015, and 2016, 626 projects, 69.9 percent, were renewable. Of the 321 projects entered in the first nine months of 2017, 256 projects, 79.8 percent, were renewable.

Table 12-17 Number of projects entered in the queue: September 30, 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	256	63	321
Total	69	2,211	1,385	3,665

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 40.3 percent of the nameplate MW currently active in the queue (Table 12-18).

Table 12-18 Queue details by fuel group: September 30, 2017

Fuel Group	Number of Projects	Percent of Projects	MW	Percent MW
Nuclear	8	0.9%	152.3	0.1%
Renewable	632	71.3%	41,260.6	40.3%
Traditional	246	27.8%	60,902.4	59.5%
Total	886	100.0%	102,315.3	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 September 30, 2017. For example, between January 1, 1997 and September 30, 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 3,590 projects in PJM generation queues. A total of 2,933 projects have been classified as new generation and 657 projects have been classified as upgrades. Wind, solar and natural gas projects have accounted for 2,827 projects, or 78.7 percent, of all 3,590 generation queue projects. A total of 52 new projects from either project classification entered the generation queue between July 1, 2017 and September 30, 2017.

Table 12-19 Status of all generation queue projects: January 1, 1997 through September 30, 2017

		Number of Projects												
Project Status	Project Classification	Natural Gas	Wind	Coal	Solar	Nuclear	Hydro	Oil	Biomass	Storage	Other	LFG	Diesel	TOTAL
In Service	New Generation	92	62	9	110	1	10	4	7	18	3	75	6	397
	Upgrade	156	15	45	16	42	16	14	6	3	4	17	3	337
Under Construction	New Generation	31	20	0	43	0	4	0	0	23	0	2	0	123
	Upgrade	22	1	4	2	0	1	0	1	2	0	0	1	34
Suspended	New Generation	16	22	0	34	0	0	0	1	6	0	1	0	80
	Upgrade	5	3	0	0	0	0	0	0	3	0	0	0	11
Withdrawn	New Generation	430	374	55	748	9	40	9	38	78	10	77	12	1,880
	Upgrade	79	15	13	12	9	2	13	2	7	2	10	1	165
Active	New Generation	74	43	0	315	1	1	0	0	16	0	3	0	453
	Upgrade	65	7	5	15	7	2	0	1	6	0	1	1	110
Total Projects	New Generation	643	521	64	1,250	11	55	13	46	141	13	158	18	2,933
	Upgrade	327	41	67	45	58	21	27	10	21	6	28	6	657

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, 76.2 percent of all hydro projects classified as upgrades are currently in service in PJM, 9.5 percent of hydro upgrades were withdrawn, 4.8 percent of hydro upgrades are under construction, and 9.5 percent of hydro upgrades are active in the queue. From January 1, 1997, through September 30, 2017, solar 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: January 1, 1997 through September 30, 2017

		Percent of Total Projects by Classification											
Project Status	Project Classification	Natural Gas	Wind	Coal	Solar	Nuclear	Hydro	Oil	Biomass	Storage	Other	LFG	Diesel
In Service	New Generation	14.3%	11.9%	14.1%	8.8%	9.1%	18.2%	30.8%	15.2%	12.8%	23.1%	47.5%	33.3%
	Upgrade	47.7%	36.6%	67.2%	35.6%	72.4%	76.2%	51.9%	60.0%	14.3%	66.7%	60.7%	50.0%
Under Construction	New Generation	4.8%	3.8%	0.0%	3.4%	0.0%	7.3%	0.0%	0.0%	16.3%	0.0%	1.3%	0.0%
	Upgrade	6.7%	2.4%	6.0%	4.4%	0.0%	4.8%	0.0%	10.0%	9.5%	0.0%	0.0%	16.7%
Suspended	New Generation	2.5%	4.2%	0.0%	2.7%	0.0%	0.0%	0.0%	2.2%	4.3%	0.0%	0.6%	0.0%
	Upgrade	1.5%	7.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	14.3%	0.0%	0.0%	0.0%
Withdrawn	New Generation	66.9%	71.8%	85.9%	59.8%	81.8%	72.7%	69.2%	82.6%	55.3%	76.9%	48.7%	66.7%
	Upgrade	24.2%	36.6%	19.4%	26.7%	15.5%	9.5%	48.1%	20.0%	33.3%	33.3%	35.7%	16.7%
Active	New Generation	11.5%	8.3%	0.0%	25.2%	9.1%	1.8%	0.0%	0.0%	11.3%	0.0%	1.9%	0.0%
	Upgrade	19.9%	17.1%	7.5%	33.3%	12.1%	9.5%	0.0%	10.0%	28.6%	0.0%	3.6%	16.7%

Table 12-21 shows the nameplate generating capacity of projects in the PJM generation queue by technology type and project classification. For example, the 374 new generation wind projects that have been withdrawn from the queue as of September 30, 2017, listed in Table 12-19 constitute 58,811.1 MW of nameplate capacity. The 509 new generation and upgrade natural gas projects that have been withdrawn in the same time period constitute 197,194.6 MW of nameplate capacity.

Table 12-21 Status of all generation capacity (MW) in the PJM generation queue: January 1, 1997 through September 30, 2017

		Project MW												
Project Status	Project Classification	Natural Gas	Wind	Coal	Solar	Nuclear	Hydro	Oil	Biomass	Storage	Other	LFG	Diesel	TOTAL
In Service	New Generation	24,990.1	6,871.2	1,378.0	873.4	9.0	565.6	607.0	225.7	161.4	50.0	406.9	69.5	36,207.7
	Upgrade	7,413.4	33.7	747.5	19.4	3,912.8	605.6	125.8	58.8	36.4	547.5	54.5	25.3	13,580.6
Under Construction	New Generation	14,469.1	3,149.7	0.0	768.6	0.0	35.6	0.0	0.0	40.6	0.0	11.2	0.0	18,474.8
	Upgrade	1,485.1	0.0	108.0	4.5	0.0	17.0	0.0	62.5	52.0	0.0	0.0	0.0	1,729.1
Suspended	New Generation	4,491.7	3,706.0	0.0	387.1	0.0	0.0	0.0	16.0	75.8	0.0	0.9	0.0	8,677.5
	Upgrade	365.7	175.0	0.0	0.0	0.0	0.0	0.0	0.0	30.0	0.0	0.0	0.0	570.7
Withdrawn	New Generation	188,341.0	58,811.0	33,511.6	12,407.6	8,161.0	1,988.0	1,721.0	1,061.5	792.0	843.8	443.4	63.9	308,145.9
	Upgrade	8,853.6	380.6	865.0	167.8	916.0	56.0	589.0	37.1	92.1	24.0	48.7	4.0	12,033.9
Active	New Generation	34,094.7	8,285.3	0.0	16,823.4	28.0	15.0	0.0	0.0	189.9	0.0	19.8	0.0	59,456.0
	Upgrade	5,037.5	264.8	91.0	936.9	124.3	39.6	0.0	4.0	98.8	0.0	0.0	4.0	6,600.9
Total Projects	New Generation	266,386.6	80,823.3	34,889.6	31,260.1	8,198.0	2,604.2	2,328.0	1,303.2	1,259.6	893.8	882.1	133.4	430,961.9
	Upgrade	23,155.3	854.0	1,811.5	1,128.6	4,953.1	718.2	714.8	162.4	309.3	571.5	103.2	33.3	34,515.2

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 the first nine months of 2017 was primarily a result of new projects in AEP.

Figure 12-3 Queue project MW by fuel type and queue entry year: January 1, 1997 through September 30, 2017

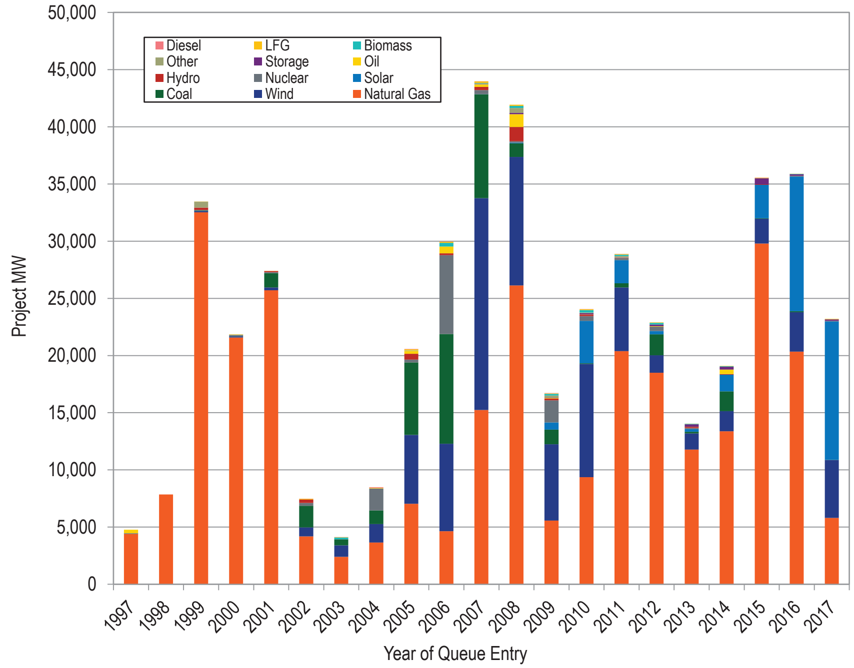


Table 12-22 Status of all generation queue projects as percent of total MW in project classification: January 1, 1997 through September 30, 2017

		Percent of Total Project MW by Classification											
Project Status	Project Classification	Natural Gas	Wind	Coal	Solar	Nuclear	Hydro	Oil	Biomass	Storage	Other	LFG	Diesel
In Service	New Generation	9.4%	8.5%	3.9%	2.8%	0.1%	21.7%	26.1%	17.3%	12.8%	5.6%	46.1%	52.1%
	Upgrade	32.0%	3.9%	41.3%	1.7%	79.0%	84.3%	17.6%	36.2%	11.8%	95.8%	52.8%	76.0%
Under Construction	New Generation	5.4%	3.9%	0.0%	2.5%	0.0%	1.4%	0.0%	0.0%	3.2%	0.0%	1.3%	0.0%
	Upgrade	6.4%	0.0%	6.0%	0.4%	0.0%	2.4%	0.0%	38.5%	16.8%	0.0%	0.0%	0.0%
Suspended	New Generation	1.7%	4.6%	0.0%	1.2%	0.0%	0.0%	0.0%	1.2%	6.0%	0.0%	0.1%	0.0%
	Upgrade	1.6%	20.5%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	9.7%	0.0%	0.0%	0.0%
Withdrawn	New Generation	70.7%	72.8%	96.1%	39.7%	99.5%	76.3%	73.9%	81.5%	62.9%	94.4%	50.3%	47.9%
	Upgrade	38.2%	44.6%	47.8%	14.9%	18.5%	7.8%	82.4%	22.8%	29.8%	4.2%	47.2%	12.0%
Active	New Generation	12.8%	10.3%	0.0%	53.8%	0.3%	0.6%	0.0%	0.0%	15.1%	0.0%	2.2%	0.0%
	Upgrade	21.8%	31.0%	5.0%	83.0%	2.5%	5.5%	0.0%	2.5%	31.9%	0.0%	0.0%	12.0%

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, 72.8 percent of wind projects classified as new generation have been withdrawn from the queue between January 1, 1997, and September 30, 2017.

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 September 30, 2017, by zone. Of the 139 natural gas projects classified either as new generation or upgrade currently active in the PJM generation queue, 60 projects, 43.2 percent, are located within AEP, ComEd and APS.

Table 12-23 Status of all natural gas generation queue projects: January 1, 1997 through September 30, 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	1	7	2	6	2	0	1	5	7	0	0	8	3	6	8	7	9	12	0	91
	Upgrade	7	15	9	1	1	12	6	0	30	16	0	0	5	2	9	5	5	6	27	0	156
Under Construction	New Generation	3	2	3	1	1	0	0	1	3	0	1	0	1	1	2	3	2	5	2	0	31
	Upgrade	0	1	1	1	0	2	0	0	3	0	0	0	1	0	5	0	1	4	3	0	22
Suspended	New Generation	2	2	4	0	0	0	0	0	0	1	0	0	1	0	0	5	1	0	0	0	16
	Upgrade	0	0	1	0	0	0	0	0	0	0	0	0	1	0	0	1	2	0	0	0	5
Withdrawn	New Generation	26	17	39	13	8	10	0	1	17	17	2	3	25	25	42	50	33	39	61	2	430
	Upgrade	6	7	5	4	0	2	0	1	7	4	0	0	5	8	3	4	3	4	16	0	79
Active	New Generation	4	11	6	4	0	11	1	0	3	1	0	0	1	0	1	5	0	5	21	0	74
	Upgrade	4	9	6	4	0	17	0	0	11	1	0	0	2	3	0	2	0	5	1	0	65
Total Projects	New Generation	42	33	59	20	15	23	1	3	28	26	3	3	36	29	51	71	43	58	96	2	642
	Upgrade	17	32	22	10	1	33	6	1	51	21	0	0	14	13	17	12	11	19	47	0	327

Table 12-24 shows the status of all gas projects by MW that entered PJM generation queues from January 1, 1997 through September 30, 2017, by zone. Of the 39,132.2 MW of natural gas projects classified either as new generation or upgrade currently active in the PJM generation queue, 21,416.8 MW, 54.7 percent, are located within AEP, ComEd and APS.

Table 12-24 Status of all natural gas generation capacity (MW) in the PJM generation queue: January 1, 1997 through September 30, 2017

Project Status	Project Classification	Project MW																				
		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	1,016.2	580.0	1,701.0	815.5	390.0	629.0	0.0	20.0	4,011.0	1,122.2	0.0	0.0	2,070.3	1,397.0	2,464.0	1,267.1	840.0	2,826.9	2,804.9	0.0	23,955.1
	Upgrade	265.7	414.0	857.7	40.0	2.5	864.0	60.0	0.0	1,446.7	200.0	0.0	0.0	224.0	665.0	780.5	87.0	121.1	327.3	1,057.9	0.0	7,413.4
Under Construction	New Generation	453.5	1,417.0	954.4	800.0	1.3	0.0	0.0	513.0	2,855.1	0.0	205.0	0.0	0.4	450.0	760.5	1,659.9	755.0	3,074.0	570.0	0.0	14,469.1
	Upgrade	0.0	6.0	0.0	161.0	0.0	32.6	0.0	0.0	225.0	0.0	0.0	0.0	0.0	0.0	241.0	0.0	64.5	524.0	231.0	0.0	1,485.1
Suspended	New Generation	606.0	1,579.0	574.7	0.0	0.0	0.0	0.0	0.0	0.0	291.0	0.0	0.0	440.0	0.0	0.0	107.0	894.0	0.0	0.0	0.0	4,491.7
	Upgrade	0.0	0.0	20.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	200.0	0.0	0.0	1.6	144.1	0.0	0.0	0.0	365.7
Withdrawn	New Generation	6,923.8	9,575.0	16,744.0	5,420.7	3,122.1	4,533.0	0.0	134.5	10,475.0	4,608.4	665.0	991.8	11,461.2	13,001.0	23,120.0	17,174.0	20,414.2	16,451.7	23,518.7	6.9	188,341.0
	Upgrade	122.8	711.0	579.0	111.0	0.0	75.0	0.0	36.0	305.3	668.0	0.0	0.0	253.0	1,742.0	240.0	1,040.6	85.0	480.0	2,404.9	0.0	8,853.6
Active	New Generation	805.4	7,203.0	3,960.9	4,047.0	0.0	6,779.2	1,150.0	0.0	3,544.5	451.0	0.0	0.0	1,092.2	0.0	220.0	542.7	0.0	1,898.8	2,400.0	0.0	34,094.7
	Upgrade	273.6	387.0	424.7	183.0	0.0	2,662.0	0.0	0.0	410.1	60.0	0.0	0.0	34.9	99.1	0.0	91.0	0.0	361.0	51.1	0.0	5,037.5
Total Projects	New Generation	9,805.0	20,354.0	23,935.0	11,083.2	3,513.4	11,941.2	1,150.0	667.5	20,885.6	6,472.6	870.0	991.8	15,064.1	14,848.0	26,564.5	20,750.7	22,903.2	24,251.4	29,293.6	6.9	265,351.6
	Upgrade	662.1	1,518.0	1,881.4	495.0	2.5	3,633.6	60.0	36.0	2,387.1	928.0	0.0	0.0	711.9	2,506.1	1,261.5	1,220.2	414.7	1,692.3	3,744.9	0.0	23,155.3

Wind Project Analysis

Table 12-25 shows the status of all wind generation projects that entered PJM generation queues from January 1, 1997 through September 30, 2017, by zone. Of the 77 wind projects to achieve in service status, 68 projects, 88.3 percent are located within ComEd, AEP, APS and PENELEC. Of the 50 wind projects currently active in the PJM generation queue, 40 projects, 80.0 percent are located within ComEd, AEP, APS and PENELEC.

Table 12-25 Status of all wind generation queue projects: January 1, 1997 through September 30, 2017

	Project	Number of Projects																				
Project Status	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	1	9	11	0	0	17	0	0	0	0	0	0	0	0	0	20	0	4	0	0	62
	Upgrade	0	0	3	0	0	2	0	0	0	0	0	0	0	0	0	6	0	4	0	0	15
Under Construction	New Generation	0	5	5	0	0	4	0	0	4	1	0	0	0	0	0	1	0	0	0	0	20
	Upgrade	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Suspended	New Generation	1	11	2	1	0	1	2	0	1	0	0	0	0	0	0	2	0	1	0	0	22
	Upgrade	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3
Withdrawn	New Generation	15	81	39	6	0	94	13	0	16	7	0	1	0	0	0	61	0	40	1	0	374
	Upgrade	1	0	6	0	0	1	0	0	1	0	0	0	0	0	0	4	0	2	0	0	15
Active	New Generation	0	19	2	2	0	12	0	0	2	2	0	0	0	0	0	1	0	3	0	0	43
	Upgrade	0	0	2	0	0	2	0	0	1	0	0	0	0	0	0	2	0	0	0	0	7
Total Projects	New Generation	17	125	59	9	0	128	15	0	23	10	0	1	0	0	0	85	0	48	1	0	521
	Upgrade	2	1	13	0	0	5	0	0	2	0	0	0	0	0	0	12	0	6	0	0	41

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 September 30, 2017, by zone. Of the 6,904.9 MW of wind generation capacity to achieve in service status, 6,670.9 MW, or 96.6 percent of nameplate capacity is located within ComEd, AEP, APS and PENELEC. Of the 8,550.1 MW of wind generation capacity currently active in the PJM generation queue, 7,163.2 MW of generation capacity or 83.8 percent is located within ComEd, AEP, APS and PENELEC.

Table 12-26 Status of all wind generation capacity (MW) in the PJM generation queue: January 1, 1997 through September 30, 2017

	Project	Project MW																				
Project Status	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	7.5	2,252.0	1,004.0	0.0	0.0	2,413.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	995.0	0.0	199.2	0.0	0.0	6,871.2
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6.4	0.0	27.3	0.0	0.0	33.7
Under Construction	New Generation	0.0	638.3	572.6	0.0	0.0	978.5	0.0	0.0	740.3	150.0	0.0	0.0	0.0	0.0	0.0	70.0	0.0	0.0	0.0	0.0	3,149.7
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Suspended	New Generation	20.0	1,878.3	151.1	500.0	0.0	500.0	300.0	0.0	76.6	0.0	0.0	0.0	0.0	0.0	0.0	180.0	0.0	100.0	0.0	0.0	3,706.0
	Upgrade	5.0	100.0	70.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	175.0
Withdrawn	New Generation	3,626.4	15,048.1	2,935.1	645.6	0.0	22,115.8	1,828.0	0.0	2,361.5	2,255.0	0.0	150.3	0.0	0.0	0.0	5,059.0	0.0	2,766.3	20.0	0.0	58,811.1
	Upgrade	0.0	0.0	100.0	0.0	0.0	4.0	0.0	0.0	78.0	0.0	0.0	0.0	0.0	0.0	0.0	192.6	0.0	6.0	0.0	0.0	380.6
Active	New Generation	0.0	4,770.5	197.0	315.7	0.0	1,797.0	0.0	0.0	226.6	499.6	0.0	0.0	0.0	0.0	0.0	138.0	0.0	341.1	0.0	0.0	8,285.3
	Upgrade	0.0	0.0	20.0	0.0	0.0	170.0	0.0	0.0	4.0	0.0	0.0	0.0	0.0	0.0	0.0	70.8	0.0	0.0	0.0	0.0	264.8
Total Projects	New Generation	3,653.9	24,587.2	4,859.8	1,461.3	0.0	27,804.8	2,128.0	0.0	3,405.0	2,904.6	0.0	150.3	0.0	0.0	0.0	6,442.0	0.0	3,406.6	20.0	0.0	80,823.3
	Upgrade	5.0	100.0	190.0	0.0	0.0	174.0	0.0	0.0	82.0	0.0	0.0	0.0	0.0	0.0	0.0	269.7	0.0	33.3	0.0	0.0	854.0

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 September 30, 2018, by zone. Of a total of 1,294 solar projects ever to enter the PJM generation queue, 513 projects, or 39.6 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 5.0 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, 41.1 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 329 active new generation solar projects, 138 projects, or 41.9 percent of all currently active new generation solar projects are located in Dominion. Out of 329 active new generation solar projects, 61, or 18.5 percent of all currently active new generation solar projects are located in AEP.

Table 12-27 Status of all solar generation queue projects: January 1, 1997 through September 30, 2017

	Project	Number of Projects																				
Project Status	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	5	4	3	0	1	1	1	0	7	9	0	0	39	0	1	0	0	2	37	0	110
	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	3	2	3	0	2	0	1	0	12	5	0	0	8	0	0	0	0	0	7	0	43
	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	15	0	0	0	1	0	1	2	0	0	6	1	0	1	0	0	2	0	34
	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	150	41	48	7	10	8	7	10	81	98	0	3	160	12	6	10	9	27	61	0	748
	Upgrade	1	1	0	0	0	0	0	0	5	0	0	0	5	0	0	0	0	0	0	0	12
Active	New Generation	8	60	13	3	0	16	10	3	129	46	1	2	4	2	1	1	3	2	10	0	314
	Upgrade	0	1	0	0	0	0	0	1	9	1	0	0	0	1	0	0	0	1	1	0	15
Total Projects	New Generation	166	112	82	10	13	25	20	13	230	160	1	5	217	15	8	12	12	31	117	0	1249
	Upgrade	1	2	0	0	0	0	0	1	17	10	0	0	11	1	0	0	0	1	1	0	45

Table 12-28 shows the status of all solar generation project MW that have entered the PJM generation queue from January 1, 1997 through September 30, 2017, by zone. Of a total of 32,348.7 MW of solar nameplate capacity ever to enter the PJM generation queue, 4,246.2 MW, or 13.1 percent, have been located in JCPL, AECO and PSEG, all of which are zones in New Jersey. Solar projects in Dominion have accounted for 13,325.8 MW or 41.2 percent of all solar project nameplate capacity in the PJM queue from January 1, 1997 through September 30, 2017. Solar projects in DPL have accounted for 2,881.0 MW or 8.9 percent of all solar project nameplate capacity in the PJM queue from January 1, 1997 through September 30, 2017.

Table 12-28 Current status of all solar generation capacity (MW) in the PJM generation queue: January 1, 1997 through September 30, 2017

	Project	Project MW																				
Project Status	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	38.5	14.7	44.0	0.0	1.1	9.0	2.5	0.0	172.0	118.4	0.0	0.0	266.9	0.0	3.3	0.0	0.0	15.0	188.0	0.0	873.4
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.1	0.0	0.0	0.0	16.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	19.4
Under Construction	New Generation	20.8	30.0	27.8	0.0	22.0	0.0	3.4	0.0	458.1	43.0	0.0	0.0	128.9	0.0	0.0	0.0	0.0	0.0	34.6	0.0	768.6
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.5	0.0	0.0	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	59.9	188.7	0.0	0.0	0.0	20.0	0.0	5.0	25.5	0.0	0.0	59.1	3.0	0.0	13.5	0.0	0.0	12.4	0.0	387.1
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Withdrawn	New Generation	1,632.0	1,781.6	892.1	116.1	31.3	86.8	200.5	159.4	3,313.5	1,331.4	0.0	189.9	1,291.8	467.0	51.4	34.3	122.1	283.7	422.7	0.0	12,407.6
	Upgrade	10.0	6.0	0.0	0.0	0.0	0.0	0.0	0.0	128.0	0.0	0.0	0.0	23.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	167.8
Active	New Generation	54.5	4,164.9	453.1	426.0	0.0	495.0	739.5	215.0	8,440.9	1,342.7	11.7	100.0	13.8	135.0	18.0	50.0	62.5	30.0	30.8	0.0	16,783.4
	Upgrade	0.0	20.0	0.0	0.0	0.0	0.0	0.0	75.0	800.6	20.0	0.0	0.0	0.0	20.0	0.0	0.0	0.0	0.0	1.3	0.0	936.9
Total Projects	New Generation	1,745.8	6,051.1	1,605.7	542.1	54.4	590.8	965.9	374.4	12,389.6	2,861.0	11.7	289.9	1,760.5	605.0	72.7	97.8	184.6	328.7	688.6	0.0	31,220.1
	Upgrade	10.0	26.0	0.0	0.0	0.0	0.0	0.0	75.0	936.2	20.0	0.0	0.0	40.1	20.0	0.0	0.0	0.0	0.0	1.3	0.0	1,128.6

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 September 30, 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: January 1, 1997 through September 30, 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	49	0.0	3,965.0	0.0	34.0	3.0	3,027.0	214.0	0.0	74.7	0.0	7,317.7
		Unrelated	403	501.1	10,292.0	7.5	448.4	83.8	24,246.0	0.0	66.0	6,998.4	26,467.0	69,110.2
AES	DAY	Related	16	0.0	1,347.5	0.0	0.0	0.0	51.0	0.0	0.0	24.0	0.0	1,422.5
		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	83	64.0	301.0	0.0	340.0	0.0	13,215.0	1,944.0	0.0	251.4	142.0	16,257.4
		Unrelated	358	343.7	20.0	10.0	35.1	184.0	12,105.1	0.0	156.3	16,977.8	3,067.0	32,899.0
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	276	90.0	1,926.0	42.0	22.7	112.9	15,669.4	0.0	20.0	1,218.3	28,784.5	47,885.8
	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	266	84.0	653.0	0.0	0.0	70.0	6,773.6	0.0	30.0	2,996.9	2,809.6	13,417.1
	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	69	0.0	0.0	0.0	0.0	12.5	22,698.9	0.0	0.0	180.8	0.0	22,892.2
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	317	177.2	4,057.0	53.8	371.3	125.8	22,568.4	0.0	96.0	1,875.7	5,522.7	34,847.8
	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	2	0.0	0.0	0.0	20.0	0.0	100.0	0.0	0.0	0.0	0.0	120.0
		Unrelated	323	30.0	0.0	0.0	1.6	24.4	15,796.0	0.0	0.0	1,821.4	90.6	17,763.9
	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	101	0.0	24.0	0.0	0.0	11.7	12,802.1	381.0	0.0	125.2	0.0	13,344.0
		Unrelated	185	0.0	0.0	0.0	1,000.0	24.4	18,676.0	0.0	45.5	574.5	20.0	20,340.3
	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
Consolidated Edison, Inc.		Unrelated	2	0.0	0.0	0.0	0.0	0.0	7.1	0.0	0.0	0.0	0.0	7.1
		Related	396	64.0	9,398.5	0.0	723.0	22.4	49,070.1	11,179.1	0.0	536.3	538.0	71,531.4
Total		Unrelated	3,270	1,376.6	27,322.6	193.8	2,513.4	974.6	245,831.8	1,972.0	1,465.3	37,919.4	84,715.1	404,284.5

Table 12-30 Relationship between project developer and Transmission Owner for all solar projects MW in PJM interconnection queue: January 1, 1997 through September 30, 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	4,845.6	5,963.7
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	7.0	224.4	251.4
		Unrelated	140.1	122.9	205.0	2,083.5	12,935.1	15,486.6
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	317.0	401.8
	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	769.3	1,680.7
	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	0.0	0.0
		Unrelated	204.1	175.5	92.9	1,259.0	89.7	1,821.2
	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	8.2	1.2	125.2
		Unrelated	53.8	46.2	9.7	394.8	60.0	564.5
	RECO	Related	0.0	0.0	0.0	0.0	0.0	0.0
Consolidated Edison, Inc.		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0
		Related	144.7	42.2	0.0	39.8	285.6	512.3
Total		Unrelated	513.4	618.8	414.7	9,737.6	22,665.4	33,949.9

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 September 30, 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 12-31 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 September 30, 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: January 1, 1997 through September 30, 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	10,216.0	24,246.0
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	568.0	6,773.6
	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	6,205.5	22,568.4
	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
	RECO	Related	0.0	0.0	0.0	0.0	0.0	0.0
Consolidated Edison, Inc.		Unrelated	0.0	0.0	0.0	6.9	0.2	7.1
		Related	8,634.0	1,748.0	0.0	35,200.1	3,437.0	49,019.1
Total		Unrelated	19,947.7	15,868.3	1,751.8	156,912.0	50,695.1	245,174.8

Table 12-32 Relationship between project developer and Transmission Owner for all wind project MW in PJM interconnection queue: January 1, 1997 through September 30, 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	6,331.4	25,383.8
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	APS	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
	RECO	Related	0.0	0.0	0.0	0.0	0.0	0.0
Consolidated Edison, Inc.		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0
		Related	396.0	12.0	0.0	130.0	0.0	538.0
Total		Unrelated	6,519.0	3,657.3	3,365.0	56,063.7	11,961.9	81,566.8

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 September 30, 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.

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.[33] 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.[34]

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.[35] Table 12-33 shows that 69.4 percent of the requested outages were planned for less than or equal to five days and 9.5 percent of requested outages were planned for greater than 30 days in the 2017/2018 planning period. It also shows that 77.3 percent of the requested outages were planned for less than or equal to five days and 6.7 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.[36] The outage data in the analysis for the day-ahead market are for outages scheduled to occur from January 1, 2015, through September 30, 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	15,609	77.3%	7,073	69.4%
>5 & <=30	3,223	16.0%	2,149	21.1%
>30	1,348	6.7%	964	9.5%
Total	20,180	100.0%	10,186	100.0%

After receiving a transmission facility outage request from a TO, PJM assigns a received status to the request based on its submission date and outage planned duration. The received status can be On Time or Late, as defined in Table 12-34.[37]

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.[38]

33 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).
34 See PJM. "Manual 3: Transmission Operations," Rev. 51 (June 1, 2017), p.69.
35 *Id.* p.70.
36 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.
37 See PJM. "Manual 3: Transmission Operations," Rev. 51 (June 1, 2017), at 69–70.
38 See "*Report of PJM Interconnection, L.L.C. on Transmission Oversight Procedures*," Docket No. EL01-122-000 (November 2, 2001).

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 shows a summary of requests by received status. In the 2017/2018 planning period, 38.3 percent of outage requests received were late. In the 2016/2017 planning period, 51.3 percent of outage requests received were 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	7,885	7,724	15,609	49.5%	4,359	2,714	7,073	38.4%
>5 & <=30	1,492	1,731	3,223	53.7%	1,469	680	2,149	31.6%
>30	441	907	1,348	67.3%	458	506	964	52.5%
Total	9,818	10,362	20,180	51.3%	6,286	3,900	10,186	38.3%

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.[39] 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, 9.6 percent were for emergency outages. Of all outage requests scheduled to occur in the 2016/2017 planning period, 13.8 percent were for emergency outages.

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	2,173	13,436	15,609	13.9%	729	6,344	7,073	10.3%
>5 & <=30	430	2,793	3,223	13.3%	151	1,998	2,149	7.0%
>30	188	1,160	1,348	13.9%	100	864	964	10.4%
Total	2,791	17,389	20,180	13.8%	980	9,206	10,186	9.6%

PJM will approve all transmission outage requests that are submitted on time and do not jeopardize the reliability of the PJM system. PJM will approve all transmission outage requests that are submitted late and are not expected to cause congestion on the PJM system and do not jeopardize the reliability of the PJM system. Each outage is studied and if it is expected to cause a constraint to exceed a limit, PJM will flag the outage ticket as "congestion expected."[40]

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

Table 12-37 is a summary of outage requests by congestion status. Of all outage requests submitted to occur in the 2017/2018 planning period, 9.5 percent were expected to cause congestion. Of all the outage requests that were expected to cause congestion, 3.1 percent (30 out of 966) were denied

39 PJM. "Manual 3: Transmission Operations," Rev. 51 (June 1, 2017) at 81.
40 PJM added this definition to Manual 38 in February 2017. PJM. "Manual 38: Operations Planning," Rev. 10 (February 1, 2017) at 17.

by PJM in the 2017/2018 planning period and 15.8 percent (153 out of 966) were cancelled (Table 12-39). Of all outage requests submitted to occur in the 2016/2017 planning period, 8.6 percent were expected to cause congestion. Of all the outage requests that were expected to cause congestion, 3.7 percent (64 out of 1,744) were denied by PJM in the 2016/2017 planning period and 18.0 percent (314 out of 1,744) 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	1,298	14,311	15,609	8.3%	598	6,475	7,073	8.5%
>5 & <=30	329	2,894	3,223	10.2%	257	1,892	2,149	12.0%
>30	117	1,231	1,348	8.7%	111	853	964	11.5%
Total	1,744	18,436	20,180	8.6%	966	9,220	10,186	9.5%

Table 12-38 shows the outage requests summary by received status, congestion status and emergency status. In the 2017/2018 planning period, 28.8 percent of requests were submitted late and were nonemergency while 1.4 percent of requests (146 out of 10,186) were late, nonemergency, and expected to cause congestion. In the 2016/2017 planning period, 37.6 percent of request were submitted late and were nonemergency while 1.9 percent of requests (385 out of 20,180) 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	2,662	2,776	13.8%	52	914	966	9.5%
	Non Emergency	385	7,201	7,586	37.6%	146	2,788	2,934	28.8%
On Time	Emergency	1	14	15	0.1%	2	12	14	0.1%
	Non Emergency	1,244	8,559	9,803	48.6%	766	5,506	6,272	61.6%
Total		1,744	18,436	20,180	100.0%	966	9,220	10,186	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.[41] 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, 3.1 percent (30 out of 966) were denied by PJM in the 2017/2018 planning period, 41.3 percent were complete and 15.8 percent (153 out of 966) were cancelled. Of all the outage requests that were expected to cause congestion, 3.7 percent (64 out of 1,744) were denied by PJM in the 2016/2017 planning period, 78.1 percent were complete and 18.0 percent (314 out of 1,744) were cancelled.

41 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%	8	38	4	0	52	73.1%
	Non Emergency	63	280	2	40	385	72.7%	17	79	35	13	146	54.1%
On Time	Emergency	0	1	0	0	1	100.0%	2	0	0	0	2	0.0%
	Non Emergency	241	978	2	23	1,244	78.6%	126	282	333	17	766	36.8%
Total		314	1,362	4	64	1,744	78.1%	153	399	372	30	966	41.3%

There are clear rules defined for assigning On Time or Late status for submitted outage requests in both the PJM Tariff and PJM Manuals.[42] However, the On Time or Late status only affects the priority that PJM assigns for processing the outage request. In the 2016/2017 planning period, many (72.7 percent or 280 out of 385) outages that were nonemergency, expected to cause congestion, and late transmission outages were approved and completed. 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

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	15,609	3,153	20.2%	1,809	11.6%	7,073	1,039	14.7%	679	9.6%
>5 & <=30	3,223	1,890	58.6%	186	5.8%	2,149	549	25.5%	61	2.8%
>30	1,348	903	67.0%	38	2.8%	964	353	36.6%	22	2.3%
Total	20,180	5,946	29.5%	2,033	10.1%	10,186	1,941	19.1%	762	7.5%

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, 19.1 percent of transmission outage requests were approved by PJM and then rescheduled by the TOs, and 7.5 percent of the transmission outages were approved by PJM and subsequently cancelled by the TOs. In the 2016/2017 planning period, 29.5 percent of transmission outage requests were approved by PJM and then rescheduled by the TO, and 10.1 percent of the transmission outages were approved by PJM and subsequently cancelled by the TO.

42 OA Schedule 1 § 1.9.2.

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

A transmission outage ticket with a duration exceeding five days with an On Time status can retain its On Time status if the outage is rescheduled to a future month, and the revision is submitted by the first of the month prior to the revised month in which the outage will occur.[44] 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.

43 PJM. "Manual 3: Transmission Operations," Rev. 51 (June 7, 2017) at 70.
44 *Id.*

Table 12-41 shows that there were 7,201 transmission equipment planned outages in the 2017/2018 planning period, of which 1,024 were planned outages longer than 30 days, and of which 147 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.

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	1,173	9.5%	877	12.2%
	Yes	221	1.8%	147	2.0%
<= 30 Days		10,897	88.7%	6,177	85.8%
Total		12,291	100.0%	7,201	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 28 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	1.8%	0	0.0%
>31 & <=62	26	11.8%	28	19.0%
>62 & <=93	12	5.4%	24	16.3%
>93	179	81.0%	95	64.6%
Total	221	100.0%	147	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.[45]

In the 2017/2018 planning period, 224 outage requests were included in the annual FTR market outage list and 9,962 outage requests were not included. In the 2016/2017 planning period, 212 outage requests were included in the annual FTR market outage list and 19,968 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 shows that 3.1 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 12.1 percent of the outage requests (27 out of 224) modeled in the Annual FTR Market for the planning period were submitted late according to outage submission rules. It also shows that 5.2 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 12.3 percent of the outage requests (26 out of 212) modeled in the Annual FTR Market for the planning period were submitted late according to outage submission rules.

45 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 12-43 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	5.2%	5	2	7	3.1%
>=2 weeks & <2 months	78	2	80	37.7%	86	9	95	42.4%
>=2 months	98	23	121	57.1%	106	16	122	54.5%
Total	186	26	212	100.0%	197	27	224	100.0%

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.

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	5	5	100.0%
	>=2 weeks & <2 months	0	78	78	100.0%	0	86	86	100.0%
	>=2 months	0	98	98	100.0%	0	106	106	100.0%
	Total	0	186	186	100.0%	0	197	197	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	16	16	100.0%
	Total	2	24	26	92.3%	0	27	27	100.0%

PJM determines expected congestion for both On Time and Late outage requests. A Late outage request may be denied or cancelled if it is expected to cause congestion. Table 12-45 shows a summary of requests by expected congestion and received status. Overall, 11.1 percent (3 out of 27) 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.

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%	2	3	5	40.0%
	>=2 weeks & <2 months	17	61	78	21.8%	22	64	86	25.6%
	>=2 months	25	73	98	25.5%	24	82	106	22.6%
	Total	44	142	186	23.7%	48	149	197	24.4%
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%	2	14	16	12.5%
	Total	3	23	26	11.5%	3	24	27	11.1%

Table 12-46 shows that 17.9 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 40.0 percent for the 2016/2017 planning period. Table 12-46 also shows that 11.5 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 23.1 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%	2	28.6%
	Denied	0	0.0%	0	0.0%
	Cancelled	1	9.1%	3	42.9%
	Revised	0	0.0%	0	0.0%
	Active	0	0.0%	0	0.0%
	Completed	10	90.9%	2	28.6%
Total Submission		11	100.0%	7	100.0%
>=2 weeks & <2 months	In Progress	0	0.0%	45	47.4%
	Approved	0	0.0%	2	2.1%
	Cancelled	32	40.0%	17	17.9%
	Revised	0	0.0%	1	1.1%
	Active	0	0.0%	23	24.2%
	Completed	48	60.0%	7	7.4%
Total Submission		80	100.0%	95	100.0%
>=2 months	In Progress	0	0.0%	52	42.6%
	Approved	0	0.0%	0	0.0%
	Cancelled	28	23.1%	14	11.5%
	Revised	0	0.0%	1	0.8%
	Active	5	4.1%	50	41.0%
	Completed	88	72.7%	5	4.1%
Total Submission		121	100.0%	122	100.0%

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	1,341	7,444	84.7%	257	8,535	97.1%	1,485	3,609	70.8%	163	2,921	94.7%
>=2 weeks & <2 months	418	327	43.9%	148	914	86.1%	627	259	29.2%	102	387	79.1%
>=2 months	83	19	18.6%	168	314	65.1%	100	9	8.3%	168	132	44.0%
Total	1,842	7,790	80.9%	573	9,763	94.5%	2,212	3,877	63.7%	433	3,440	88.8%

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, 224 outage requests were modeled and 9,962 outage requests were not modeled in the Annual FTR Market. In the 2016/2017 planning period, 212 outage requests were modeled and 19,968 outage requests were not modeled in the Annual FTR Market.

Table 12-47 shows that 8.3 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. Table 12-47 also shows that 18.6 percent of outage requests not modeled in the Annual FTR Auction with duration longer than or equal to two months, labelled Late according to the rules, were submitted after the Annual FTR Auction bidding opening date in the 2017/2018 planning period.

Table 12-48 shows that 31.1 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 77.4 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	7,383	8,535	86.5%	2,234	2,921	76.5%
>=2 weeks & <2 months	834	914	91.2%	215	387	55.6%
>=2 months	243	314	77.4%	41	132	31.1%
Total	8,460	9,763	86.7%	2,490	3,440	72.4%

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.[46] 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, 35.2 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 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.

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

Table 12-49 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%				
NOV	365	172	537	32.0%				
DEC	289	130	419	31.0%				
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%	178	97	274	35.2%

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%
	Avg	27	4	7	51	1	86	100	274	18.6%

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 12-51 shows that on average, 8.8 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 9.9 percent in the 2016/2017 planning period. On average, 72.4 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 70.6 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%	649	89	12.1%	309	848	73.3%
JUL	274	74	21.3%	251	698	73.6%	296	46	13.5%	246	607	71.2%
AUG	413	92	18.2%	259	733	73.9%	349	20	5.4%	213	649	75.3%
SEP	964	156	13.9%	292	772	72.6%	887	56	5.9%	261	594	69.5%
OCT	1,092	89	7.5%	430	901	67.7%						
NOV	888	56	5.9%	389	832	68.1%						
DEC	604	44	6.8%	340	723	68.0%						
JAN	435	32	6.9%	243	592	70.9%						
FEB	463	24	4.9%	303	672	68.9%						
MAR	1,070	92	7.9%	359	804	69.1%						
APR	1,144	99	8.0%	340	789	69.9%						
MAY	1,151	146	11.3%	356	966	73.1%						
Avg	766	84	9.9%	325	781	70.6%	545	53	8.8%	257	675	72.4%

Table 12-52 shows that on average, 71.0 percent of late outage requests which were not modeled in the Monthly Balance of Planning Period FTR Auction, submitted after the Monthly Balance of Planning Period FTR Auction bidding opening dates, were approved and 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	848	73.9%
JUL	476	698	68.2%	410	607	67.5%
AUG	523	733	71.4%	473	649	72.9%
SEP	495	772	64.1%	406	594	68.4%
OCT	644	901	71.5%			
NOV	536	832	64.4%			
DEC	534	723	73.9%			
JAN	401	592	67.7%			
FEB	447	672	66.5%			
MAR	580	804	72.1%			
APR	575	789	72.9%			
MAY	668	966	69.2%			
Avg	543	781	69.5%	479	675	71.0%

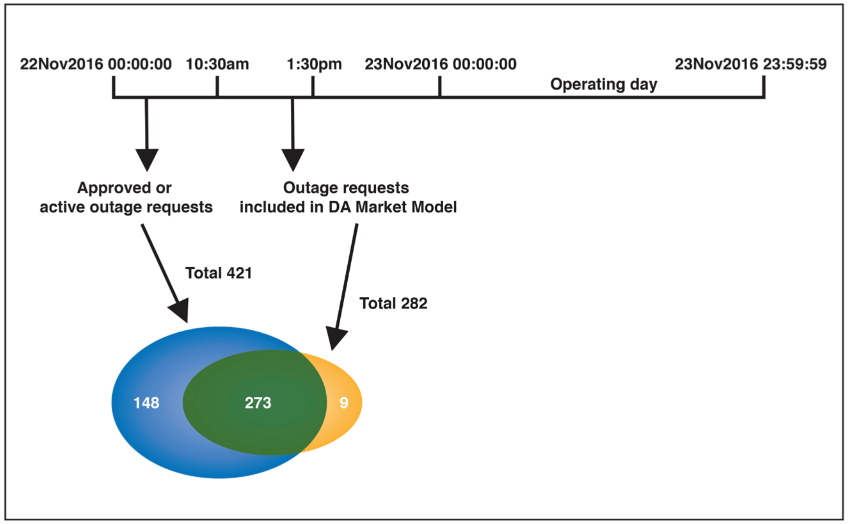
Transmission Facility Outage Analysis in the Day-Ahead Energy Market

Transmission facility outages also affect the energy market. Just as with the FTR Market, it is critical that outages that affect the operating day are known prior to the submission of offers in the Day-Ahead Energy Market so that market participants can understand market conditions and 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.[47]

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 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 on November 22, 2016



47 PJM. "Manual 3: Transmission Operations," Rev. 51 (June 7, 2017) at 74

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: January 1, 2015 through September 30, 2017

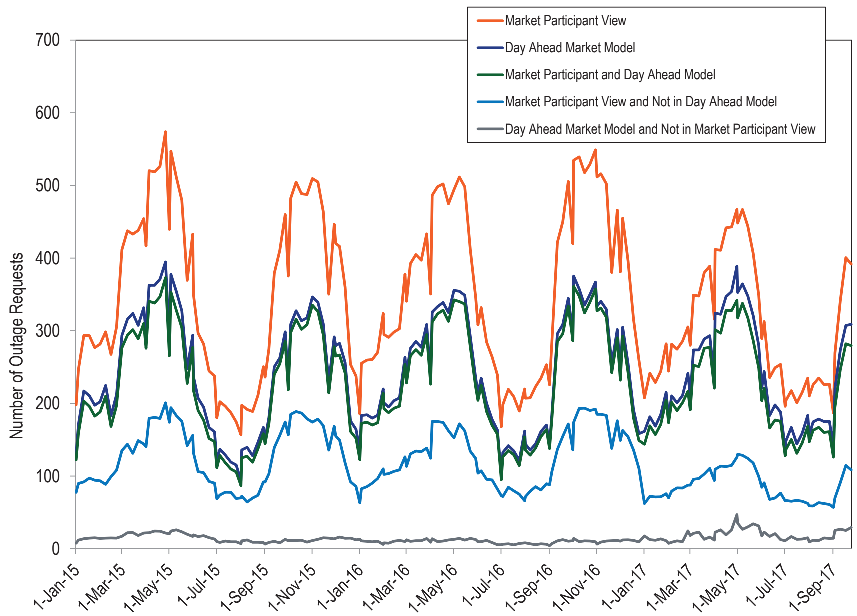


Figure 12-6 compares the weekly average number of outages included as inputs to the day-ahead market by PJM with the outages that actually occurred during the operating day.

Figure 12-6 Day-ahead market model outages: January 1, 2015 through September 30, 2017

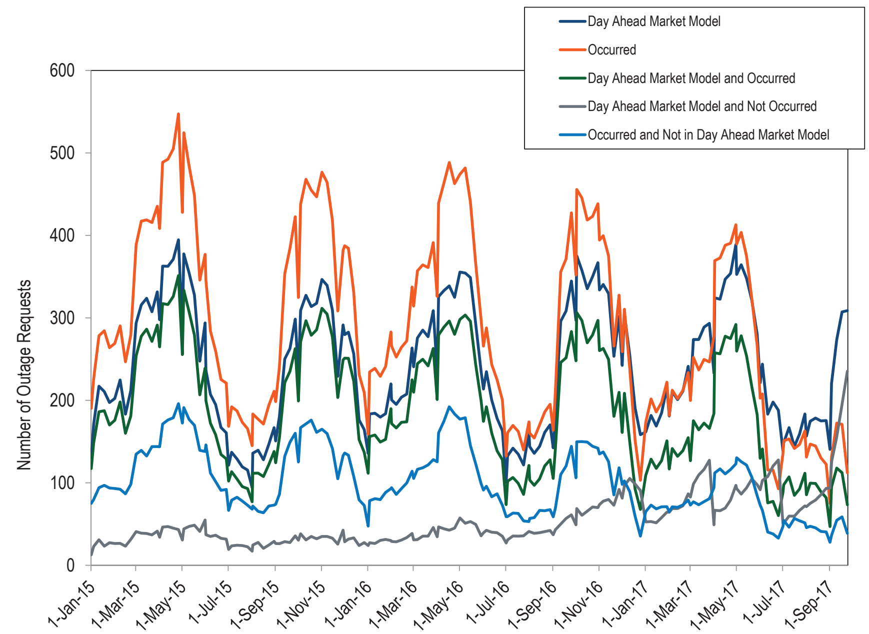


Figure 12-7 compares the weekly average number of active or approved outages available to market participants prior to the close of the day-ahead market with the outages that actually occurred during the operating day.

Figure 12-7 Approved or active outage requests: January 1, 2015 through September 30, 2017

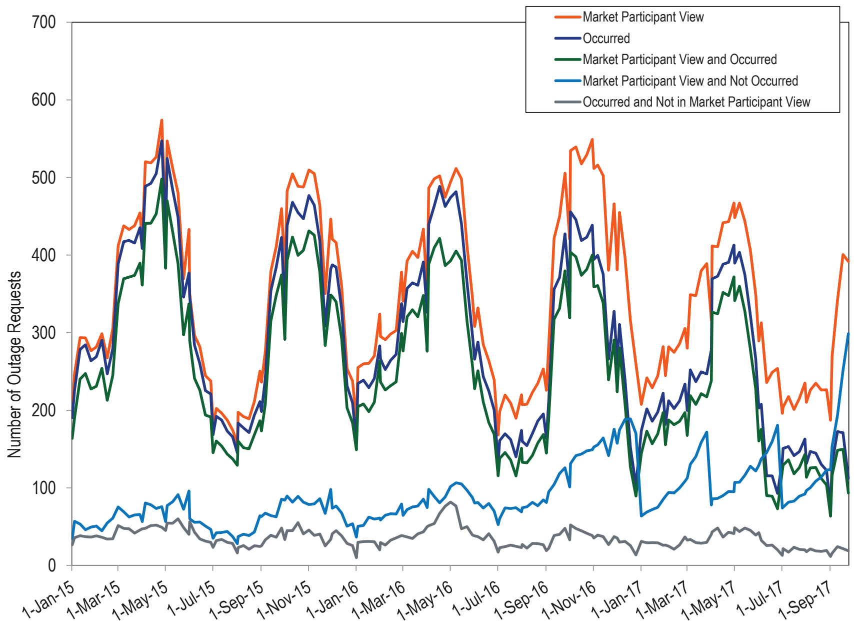


Figure 12-5, Figure 12-6, and Figure 12-7 show that on a weekly average basis, the active or approved outages available to day-ahead market participants, the outages included as inputs in the day-ahead market model and the outages that actually occurred in real time are not consistent. The active or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