Generation and Transmission Planning

Overview

Planned Generation and Retirements

- **Planned Generation.** As of September 30, 2015, 79,603.8 MW of capacity were in generation request queues for construction through 2024, compared to an average installed capacity of 185,656.0 MW as of September 30, 2015. Of the capacity in queues, 6,727.8 MW, or 8.5 percent, are uprates and the rest are new generation. Wind projects account for 14,997.1 MW of nameplate capacity or 18.8 percent of the capacity in the queues. Combined-cycle projects account for 52,950.0 MW of capacity or 66.5 percent of the capacity in the queues.
- **Generation Retirements.** As shown in Table 12-6, 27,029.0 MW have been, or are planned to be, retired between 2011 and 2020. Of that, 3,264.7 MW are planned to retire after 2015. In the first three quarters of 2015, 9,847.3 MW were retired, of which 7,661.8 MW were coal units. The coal unit retirements were a result of the EPA's Mercury and Air Toxics Standards (MATS) and low gas prices.
- **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 steam units retire. While only 1,947.0 MW of coal fired steam capacity are currently in the queue, 55,474.28 MW of gas fired capacity are in the queue. The replacement of coal steam units by units burning natural gas could significantly affect future congestion, the role of firm and interruptible gas supply, and natural gas supply infrastructure.

Generation and Transmission Interconnection Planning Process

- Any entity that requests interconnection of a new generating facility, including increases to the capacity of an existing generating unit, or that requests interconnection of a merchant transmission facility, must follow the process defined in the PJM tariff to obtain interconnection service.[1] 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. Excluding currently active projects and projects currently under construction, 2,246 projects, representing 264,381.0 MW, have completed the queue process since its inception. Of those, 604 projects, 33,328.5 MW, went into service. Of the projects that entered the queue process, 87.4 percent of the MW withdrew prior to completion. Such projects may create barriers to entry for projects that would otherwise be completed by taking up queue positions, increasing interconnection costs and creating uncertainty.
- 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.
- 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. 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. There is also a potential conflict of interest when the transmission owner evaluates the interconnection requirements of new generation which is part of the same company as 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

1 See PJM, OATT Parts IV & VI.

criteria violations in this area.[2] On July 30, 2015, the PJM Board of Managers accepted PJM's recommendation to assign the project to LS Power, a non-incumbent, PSEG, and PHI with a total cost estimate between $263M and $283M.[3,4]

- 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. Since then, some developers have raised concern with the cost allocations using the new solution based dfax method.

Backbone Facilities

- PJM baseline transmission projects are implemented to resolve reliability criteria violations. PJM backbone transmission projects are a subset of significant baseline projects, which are intended to resolve multiple reliability criteria violations and congestion issues and which may have substantial impacts on energy and capacity markets. The current backbone projects are Mount Storm-Doubs, Jacks Mountain, Susquehanna-Roseland, and Surry Skiffes Creek 500kV.

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, late, or past its deadline and whether or not they will allow the outage.[5]

2 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>

3 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>

4 See letter from Terry Boston concerning the Artificial Island Project at <http://www.pjm.com/~/media/documents/reports/board-statement-on-artificial-island-project.ashx>

5 PJM. "Manual 03: Transmission Operations," Revision 46 (December 1, 2014), Section 4.

- There were 14,458 transmission outage requests submitted for the first nine months of 2015. Of the requested outages, 79.2 percent were planned for five days or shorter and 5.4 percent were planned for longer than 30 days. Of the requested outages, 49.3 percent were late according to the rules in PJM's Manual 3.
- There were 14,283 transmission outage requests submitted for the first nine months of 2014. Of the requested outages, 80.4 percent were planned for five days or shorter and 5.3 percent were planned for longer than 30 days. Of the requested outages, 49.6 percent were late according to the rules in PJM's Manual 3.

Recommendations

The MMU recommends improvements to the planning process.

- 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 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.[6] (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

6 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>.

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 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: Not 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 Q1, 2014. Status: Partially adopted, 2014.)
- 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 Q2, 2015. Status: Not adopted.)
- The MMU recommends that PJM establish fair terms of access to rights of way and property, such as at substations, in order to remove any barriers to entry and permit competition between incumbent transmission providers and merchant transmission providers in the RTEP. (Priority: Medium. First reported 2014. Status: Not adopted.)
- The MMU recommends that PJM reevaluate all transmission outage tickets 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 have a clear definition of the congestion analysis required for transmission outage requests in Manual 3. (Priority: Low. New recommendation. Status: Not adopted.)
- The MMU recommends that PJM modify the rules to reduce or eliminate the approval of late outage requests submitted after the FTR auction bidding opening date. (Priority: Low. New recommendation. Status: Not adopted.)

Conclusion

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

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

The PJM queue evaluation process should be improved to 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.

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.

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, 2015, 79,603.8 MW of capacity were in generation request queues for construction through 2024, compared to an average installed capacity of 193,587.7 MW as of September 30, 2015. Although it is clear that not all generation in the queues will be built, PJM has added capacity annually since 2000 (Table 12-1). In the first nine months of 2015, 3,138.9 MW of nameplate capacity went into service in PJM.

Table 12-1 Year-to-year capacity additions from PJM generation queue: Calendar years 2000 through September 30, 2015

Year	MW
2000	505.0
2001	872.0
2002	3,841.0
2003	3,524.0
2004	1,935.0
2005	819.0
2006	471.0
2007	1,265.0
2008	2,776.7
2009	2,515.9
2010	2,097.4
2011	5,007.8
2012	2,669.4
2013	1,126.8
2014	2,659.0
2015 (to date)	3,138.9

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-T were open for six months. Starting in February 2008, Queues U-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 AB1 is currently open.

All projects that have been entered in a queue have a status assigned. Projects listed as active are undergoing one of the studies (feasibility, system impact, facility) required to proceed. Other status options are under construction, suspended, and in-service. Withdrawn projects are removed from the queue and listed separately. A project cannot be suspended until it has reached the status of under construction. Any project that entered the queue before February 1, 2011, can be suspended for up to three years. Projects that entered the queue after February 1, 2011, face an additional restriction in that the suspension period is reduced to one year if they affect any project later in the queue.[7] 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.

Table 12-2 shows MW in queues by expected completion date and MW changes in the queues between June 30, 2015, and September 30, 2015, for ongoing projects, i.e. projects with the status active, under construction or suspended.[8] Projects that are already in service are not included here. The total MW in queues increased by 2,142.5 MW, or 2.8 percent, from 77,461.3 MW at the end of the second quarter of 2015. The change was the result of 6,030.3 MW in new projects entering the queue, 2,176.5 MW in existing projects withdrawing, and 1,002.9 MW going into service. The remaining difference is the result of projects adjusting their expected MW.

Table 12-2 Queue comparison by expected completion year (MW): June 30, 2015 vs. September 30, 2015[9]

			Quarterly Change	
Year	As of 6/30/2015	As of 9/30/2015	MW	Percent
2015	12,632.6	10,378.6	(2,253.9)	(17.8%)
2016	16,466.5	15,510.3	(956.2)	(6.2%)
2017	13,821.4	13,349.4	(472.0)	(3.5%)
2018	14,603.1	14,608.1	5.0	0.0%
2019	12,274.8	18,746.8	6,472.0	34.5%
2020	4,442.0	3,789.6	(652.4)	(17.2%)
2021	1,377.0	1,377.0	0.0	0.0%
2022	250.0	250.0	0.0	0.0%
2024	1,594.0	1,594.0	0.0	0.0%
Total	77,461.3	79,603.8	2,142.5	2.8%

Table 12-3 shows the yearly project status changes in more detail and how scheduled queue capacity has changed between June 30, 2015, and September 30, 2015. For example, 6,030.3 MW entered the queue in the second quarter of 2015, 5,695.6 MW of which are currently active and 100 MW of which were withdrawn before the quarter ended. Of the total 50,091.6 MW marked as active at the beginning of the quarter, 2,023.7 MW were withdrawn, 2,007.3 MW started construction, and 65.5 MW went into service by the end of the third quarter. The Under Construction column shows that 184.0 MW came out of suspension and 2,007.3 MW began construction in the third quarter of 2015, in addition to the 20,953.1 MW of capacity that maintained the status under construction from the previous quarter.

Table 12-3 Change in project status (MW): June 30, 2015 vs. September 30, 2015

		Status at 9/30/2015				
Status at 6/30/2015	Total at 6/30/2015	Active	Suspended	Under Construction	In Service	Withdrawn
(Entered in Q3 2015)		5,695.6	0.0	2.0	232.7	100.0
Active	50,091.6	45,460.7	0.0	2,007.3	65.5	2,023.7
Suspended	4,406.3	0.0	4,144.4	184.0	0.0	17.9
Under Construction	22,963.4	80.0	1,076.6	20,953.1	704.7	35.0
In Service	40,796.5	0.0	0.0	0.0	40,792.5	0.0
Withdrawn	281,037.5	0.0	0.0	0.0	0.0	281,037.9
Total at 9/30/2015		51,236.3	5,221.0	23,146.4	41,795.4	283,214.5

Table 12-4 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-L are either in service or have been withdrawn. As of September 30, 2015, there are 79,603.8 MW of capacity in queues that are not yet in service, of which 6.6 percent are suspended, 29.1 percent are under construction and 64.4 percent have not begun construction.

7 See PJM. Manual 14C. "Generation and Transmission Interconnection Process," Revision 8 (December 20, 2012), Section 3.7, <http://www.pjm.com/~/media/documents/manuals/m14c.ashx>.
8 Expected completion dates are entered when the project enters the queue. Actual completion dates are generally different than expected completion dates.
9 Wind and solar capacity in Table 12-2 through Table 12-5 have not been adjusted to reflect derating.

Table 12-4 Capacity in PJM queues (MW): At September 30, 2015[10]

Queue	Active	In-Service	Under Construction	Suspended	Withdrawn	Total
A Expired 31-Jan-98	0.0	8,103.0	0.0	0.0	17,347.0	25,450.0
B Expired 31-Jan-99	0.0	4,477.5	0.0	0.0	14,620.7	19,098.2
C Expired 31-Jul-99	0.0	531.0	0.0	0.0	3,470.7	4,001.7
D Expired 31-Jan-00	0.0	850.6	0.0	0.0	7,182.0	8,032.6
E Expired 31-Jul-00	0.0	795.2	0.0	0.0	8,021.8	8,817.0
F Expired 31-Jan-01	0.0	52.0	0.0	0.0	3,092.5	3,144.5
G Expired 31-Jul-01	0.0	1,189.6	0.0	0.0	17,962.3	19,151.9
H Expired 31-Jan-02	0.0	702.5	0.0	0.0	8,421.9	9,124.4
I Expired 31-Jul-02	0.0	103.0	0.0	0.0	3,728.4	3,831.4
J Expired 31-Jan-03	0.0	40.0	0.0	0.0	846.0	886.0
K Expired 31-Jul-03	0.0	218.0	0.0	0.0	2,425.4	2,643.4
L Expired 31-Jan-04	0.0	256.5	0.0	0.0	4,033.7	4,290.2
M Expired 31-Jul-04	0.0	504.8	150.0	0.0	3,705.6	4,360.4
N Expired 31-Jan-05	0.0	2,398.8	38.0	0.0	8,090.3	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	3,255.2	62.5	210.0	5,110.5	8,638.2
Q Expired 31-Jul-06	105.0	3,147.9	1,594.0	0.0	9,686.7	14,533.6
R Expired 31-Jan-07	0.0	2,046.4	488.3	800.0	19,420.6	22,755.3
S Expired 31-Jul-07	0.0	3,732.3	283.3	360.0	12,706.5	17,082.0
T Expired 31-Jan-08	675.0	1,935.0	2,011.8	428.0	22,488.3	27,538.1
U Expired 31-Jan-09	700.0	1,125.3	381.9	320.0	30,829.6	33,356.8
V Expired 31-Jan-10	1,249.2	2,018.8	1,122.3	460.0	12,036.4	16,886.7
W Expired 31-Jan-11	2,015.0	1,179.6	1,542.7	1,628.0	17,942.6	24,307.9
X Expired 31-Jan-12	3,026.0	359.0	9,003.4	361.8	17,618.0	30,368.2
Y Expired 30-Apr-13	2,718.0	826.6	4,477.5	630.8	17,336.3	25,989.0
Z Expired 30-Apr-14	7,398.0	273.5	1,400.3	22.5	5,580.8	14,675.0
AA1 Expired 31-Oct-14	10,865.3	5.3	150.3	0.0	1,275.3	12,296.2
AA2 Expired 30-Apr-15	13,789.7	0.0	0.0	0.0	2,666.0	16,455.7
AB1 Through 30-Sep-15	8,695.1	0.0	3.3	0.0	101.9	8,800.3
Total	51,236.3	41,795.4	23,146.4	5,221.0	283,214.5	404,613.6

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

Distribution of Units in the Queues

Table 12-5 shows the projects under construction, suspended, or active, by unit type, and control zone.[11] As of September 30, 2015, 79,603.8 MW of capacity were in generation request queues for construction through 2024, compared to 77,461.3 MW at June 30, 2015.[12] Table 12-5 also shows the planned retirements for each zone.

Table 12-5 Queue capacity by LDA, control zone and fuel (MW): At September 30, 2015[13]

LDA	Zone	CC	CT	Diesel	Hydro	Nuclear	Solar	Steam	Storage	Wind	Total Queue Capacity	Planned Retirements
EMAAC	AECO	1,276.0	302.5	0.0	0.0	0.0	49.2	0.0	20.0	373.0	2,020.7	8.0
	DPL	822.0	17.0	2.0	0.0	0.0	425.5	0.0	22.0	749.6	2,038.1	34.0
	JCPL	2,869.0	0.0	0.6	0.0	0.0	540.6	0.0	180.0	0.0	3,590.2	614.5
	PECO	3,614.0	0.0	9.8	10.0	0.0	0.0	0.0	40.0	0.0	3,673.8	50.8
	PSEG	3,033.9	516.0	13.6	0.0	0.0	155.1	0.0	0.0	0.0	3,718.6	611.0
	EMAAC Total	11,614.9	835.5	26.0	10.0	0.0	1,170.4	0.0	262.0	1,122.6	15,041.4	1,318.3
SWMAAC	BGE	0.0	0.0	30.3	0.0	0.4	23.1	132.0	20.1	0.0	205.9	260.0
	Pepco	2,725.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,725.6	1,204.0
	SWMAAC Total	2,725.6	0.0	30.3	0.0	0.4	23.1	132.0	20.1	0.0	2,931.5	1,464.0
WMAAC	Met-Ed	1,250.0	86.6	0.0	16.8	0.0	3.0	401.0	0.0	0.0	1,757.4	0.0
	PENELEC	3,932.0	592.3	161.8	0.0	40.0	13.5	0.0	68.4	473.3	5,281.3	10.4
	PPL	6,102.0	0.0	24.9	0.0	0.0	129.0	16.0	30.0	518.5	6,820.4	0.0
	WMAAC Total	11,284.0	678.9	186.7	16.8	40.0	145.5	417.0	98.4	991.8	13,859.1	10.4
Non-MAAC	AEP	6,111.0	51.0	9.8	102.0	34.0	101.7	220.0	62.0	6,542.0	13,233.5	0.0
	APS	5,792.4	0.0	147.4	0.0	58.2	219.6	1,733.7	51.0	663.6	8,665.9	0.0
	ATSI	4,052.0	0.8	40.7	0.0	0.0	0.0	0.0	0.0	518.0	4,611.5	0.0
	ComEd	5,200.8	603.3	26.6	0.0	22.7	14.0	27.0	120.6	3,387.0	9,402.0	0.0
	DAY	0.0	0.0	1.9	0.0	0.0	23.4	12.0	20.0	300.0	357.3	0.0
	DEOK	513.0	0.0	6.4	0.0	112.0	125.0	50.0	18.0	0.0	824.4	0.0
	DLCO	205.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	205.0	0.0
	Dominion	5,451.3	0.0	2.0	1,594.0	0.0	1,760.4	62.5	130.0	1,472.1	10,472.3	323.0
	EKPC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	149.0
	Non-MAAC Total	27,325.5	655.1	234.7	1,696.0	226.9	2,244.1	2,105.2	401.6	12,882.7	47,771.8	472.0
Total		52,950.0	2,169.5	477.7	1,722.8	267.3	3,583.1	2,654.2	782.1	14,997.1	79,603.8	3,264.7

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 steam units retire. While 55,630.8 MW of gas fired capacity are in the queue, only 1,947.0 MW of coal fired steam capacity are in the queue. The only new coal project since the second quarter of 2014 is the new Hatfield unit, with 1,710 MW of capacity. This project entered the queue in October 2014 and is intended to replace three coal units retired in October 2013 at the same location. With respect to retirements, 1,811.0 MW of coal fired steam capacity and 282.8 MW of natural gas capacity are slated for deactivation. The replacement of coal steam units by units burning natural gas could significantly affect future congestion, the role of firm and interruptible gas supply, and natural gas supply infrastructure.

Planned Retirements

As shown in Table 12-6, 27,029.0 MW have been, or are planned to be, retired between 2011 and 2020. Of that, 3,264.7 MW are planned to retire after 2015. In the first nine months of 2015, 9,847.3 MW were retired, of which 7,661.8 MW were coal units. The coal unit retirements were a result of the EPA's Mercury and Air Toxics Standards (MATS) and low gas prices.

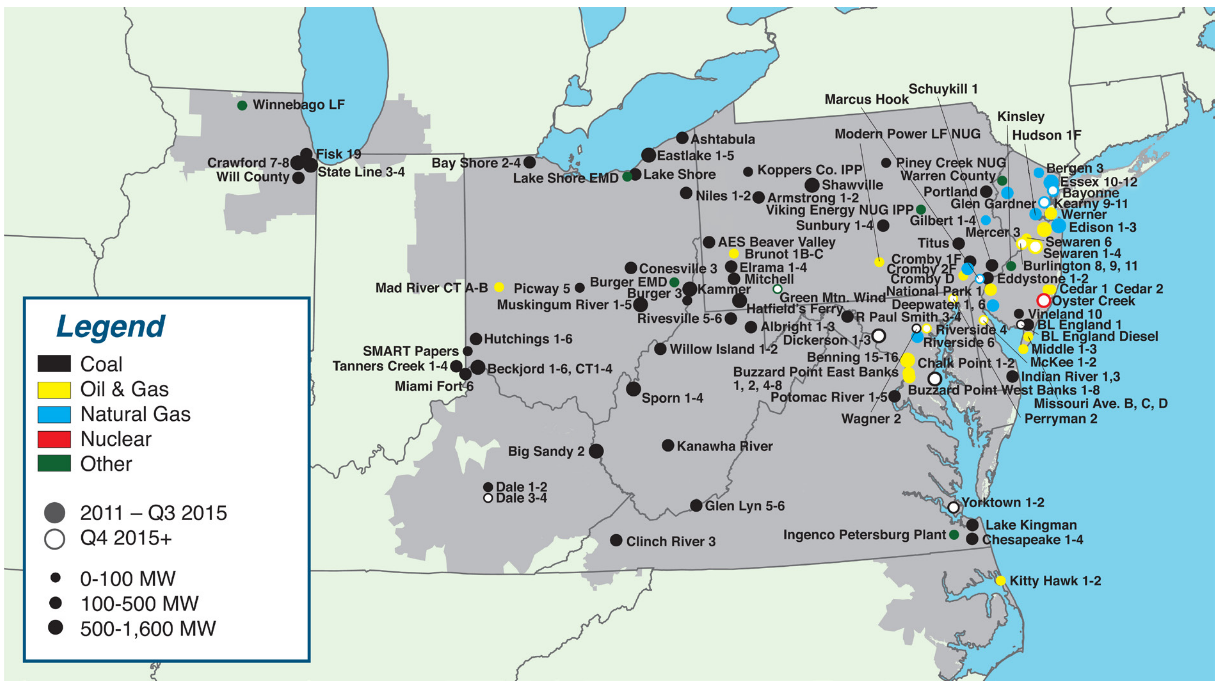
11 Unit types designated as reciprocating engines are classified as diesel.
12 Since wind resources cannot be dispatched on demand, PJM rules previously required that the unforced capacity of wind resources be derated to 20 percent of installed capacity until actual generation data are available. Beginning with Queue U, PJM derates wind resources to 13 percent of installed capacity until there is operational data to support a different conclusion. PJM derates solar resources to 38 percent of installed capacity. Based on the derating of 14,997.1 MW of wind resources and 3,583.1 MW of solar resources, the 79,603.8 MW currently active in the queue would be reduced to 64,334.8 MW.
13 This data includes only projects with a status of active, under-construction, or suspended.

Table 12-6 Summary of PJM unit retirements by fuel (MW): 2011 through 2020

	Coal	Diesel	Heavy Oil	Kerosene	Landfill Gas	Light Oil	Natural Gas	Nuclear	Wind	Wood Waste	Total
Retirements 2011	543.0	0.0	0.0	0.0	0.0	63.7	522.5	0.0	0.0	0.0	1,129.2
Retirements 2012	5,907.9	0.0	0.0	0.0	0.0	788.0	250.0	0.0	0.0	16.0	6,961.9
Retirements 2013	2,589.9	2.9	166.0	0.0	3.8	85.0	0.0	0.0	0.0	8.0	2,855.6
Retirements 2014	2,427.0	50.0	0.0	184.0	15.3	0.0	294.0	0.0	0.0	0.0	2,970.3
Retirements 2015	7,661.8	10.3	0.0	644.2	0.0	212.0	1,319.0	0.0	0.0	0.0	9,847.3
Planned Retirements 2015	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10.4	0.0	10.4
Planned Retirements Post-2015	1,811.0	59.0	108.0	0.0	0.0	0.0	661.8	614.5	0.0	0.0	3,254.3
Total	20,940.6	122.2	274.0	828.2	19.1	1,148.7	3,047.3	614.5	10.4	24.0	27,029.0

A map of these retirements between 2011 and 2020 is shown in Figure 12-1.

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



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

Table 12-7 Planned retirement of PJM units: as of September 30, 2015

Unit	Zone	ICAP (MW)	Fuel	Unit Type	Projected Deactivation Date
Yorktown 1-2	Dominion	323.0	Coal	Steam	31-Mar-16
Dale 3-4	EKPC	149.0	Coal	Steam	16-Apr-16
BL England Diesels	AECO	8.0	Diesel	Diesel	31-May-16
Riverside 4	BGE	74.0	Natural gas	Steam	01-Jun-16
McKee 1-2	DPL	34.0	Heavy Oil	Combustion Turbine	31-May-17
Sewaren 1-4	PSEG	453.0	Kerosene	Combustion Turbine	01-Nov-17
Bayonne Cogen Plant (CC)	PSEG	158.0	Natural gas	Steam	01-Nov-18
MH50 Marcus Hook Co-gen	PECO	50.8	Natural gas	Steam	13-May-19
Chalk Point 1-2	Pepco	667.0	Coal	Steam	31-May-19
Dickerson 1-3	Pepco	537.0	Coal	Steam	31-May-19
Oyster Creek	JCPL	614.5	Nuclear	Nuclear	31-Dec-19
Wagner 2	BGE	135.0	Coal	Steam	01-Jun-20
Arnold (Green Mountain) Wind Farm	PENELEC	10.4	Wind	Wind	05-Nov-15
Perryman 2	BGE	51.0	Diesel	Combustion Turbine	01-Jan-16
Total		3,264.7			

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

	Number of Units	Avg. Size (MW)	Avg. Age at Retirement (Years)	Total MW	Percent
Coal	127	164.9	55.9	20,940.6	77.5%
Diesel	7	17.5	42.7	122.2	0.5%
Heavy Oil	4	68.5	57.5	274.0	1.0%
Kerosene	20	41.4	45.5	828.2	3.1%
Landfill Gas	4	4.8	14.8	19.1	0.1%
Light Oil	15	76.6	43.8	1,148.7	4.2%
Natural Gas	51	59.8	46.3	3,047.3	11.3%
Nuclear	1	614.5	50.0	614.5	2.3%
Wind	1	10.4	15.0	10.4	0.0%
Wood Waste	2	12.0	23.5	24.0	0.1%
Total	232	116.5	0.0	27,029.0	100.0%

Table 12-8 shows the capacity, average size, and average age of units retiring in PJM, from 2011 through 2020, while Table 12-9 shows these retirements by state. The majority, 77.5 percent, of all MW retiring during this period are coal steam units. These units have an average age of 55.9 years and an average size of 164.9 MW. More than half of them, 51.5 percent, are located in either Ohio or Pennsylvania. Retirements have generally consisted of smaller sub-critical coal steam units and those without adequate environmental controls to remain viable beyond 2015.

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

State	Coal	Diesel	Heavy Oil	Kerosene	Landfill Gas	Light Oil	Natural Gas	Nuclear	Wind	Wood Waste	Total
DC	0.0	0.0	0.0	0.0	0.0	788.0	0.0	0.0	0.0	0.0	788.0
DE	254.0	0.0	34.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	288.0
IL	1,624.0	0.0	0.0	0.0	6.4	0.0	0.0	0.0	0.0	0.0	1,630.4
IN	982.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	982.0
KY	995.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	995.0
MD	1,454.0	51.0	74.0	0.0	0.0	0.0	115.0	0.0	0.0	0.0	1,694.0
NC	0.0	0.0	0.0	0.0	0.0	31.0	0.0	0.0	0.0	0.0	31.0
NJ	136.0	8.0	0.0	828.2	4.7	212.0	2,680.5	614.5	0.0	0.0	4,483.9
OH	5,658.6	60.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5,718.9
PA	5,145.0	0.0	166.0	0.0	8.0	117.7	251.8	0.0	10.4	24.0	5,722.9
VA	2,051.0	2.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,053.9
WV	2,641.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,641.0
Total	20,940.6	122.2	274.0	828.2	19.1	1,148.7	3,047.3	614.5		24.0	27,029.0

Actual Generation Deactivations in 2015

Table 12-10 shows the units that were deactivated in 2015.

Table 12-10 Unit deactivations in 2015

Company	Unit Name	ICAP (MW)	Primary Fuel	Zone Name	Average Age (Years)	Retirement Date
Calpine Corporation	Cedar 1	44.0	Kerosene	AECO	43	28-Jan-15
First Energy	Eastlake 2	109.0	Coal	ATSI	62	06-Apr-15
First Energy	Eastlake 1	109.0	Coal	ATSI	62	09-Apr-15
First Energy	Eastlake 3	109.0	Coal	ATSI	61	10-Apr-15
First Energy	Ashtabula 5	210.0	Coal	ATSI	57	11-Apr-15
First Energy	Lake Shore 18	190.0	Coal	ATSI	53	13-Apr-15
First Energy	Lake Shore EMD	4.0	Diesel	ATSI	49	15-Apr-15
NRG Energy	Will County	251.0	Coal	ComEd	58	15-Apr-15
EKPC	Dale 1-2	46.0	Coal	EKPC	61	16-Apr-15
Calpine Corporation	Cedar 2	21.6	Kerosene	AECO	43	01-May-15
NRG Energy	Gilbert 1-4	98.0	Natural gas	JCPL	45	01-May-15
NRG Energy	Glen Gardner 1-8	160.0	Natural gas	JCPL	44	01-May-15
Calpine Corporation	Middle 1-3	74.7	Kerosene	AECO	45	01-May-15
Calpine Corporation	Missouri Ave B, C, D	57.9	Kerosene	AECO	46	01-May-15
NRG Energy	Werner 1-4	212.0	Light oil	JCPL	43	01-May-15
PSEG	Bergen 3	21.0	Natural gas	PSEG	48	01-Jun-15
AEP	Big Sandy 2	800.0	Coal	AEP	46	01-Jun-15
PSEG	Burlington 8, 11	205.0	Kerosene	PSEG	48	01-Jun-15
AEP	Clinch River 3	230.0	Coal	AEP	54	01-Jun-15
PSEG	Edison 1-3	504.0	Natural gas	PSEG	44	01-Jun-15
PSEG	Essex 10-11	352.0	Natural gas	PSEG	44	01-Jun-15
PSEG	Essex 12	184.0	Natural gas	PSEG	43	01-Jun-15
AEP	Glen Lyn 5-6	325.0	Coal	AEP	65	01-Jun-15
AES Corporation	Hutchings 1-3, 5-6	271.8	Coal	DAY	65	01-Jun-15
AEP	Kammer 1-3	600.0	Coal	AEP	57	01-Jun-15
AEP	Kanawha River 1-2	400.0	Coal	AEP	62	01-Jun-15
PSEG	Mercer 3	115.0	Kerosene	PSEG	48	01-Jun-15
Duke Energy Kentucky	Miami Fort 6	163.0	Coal	DEOK	55	01-Jun-15
AEP	Muskingum River 1-5	1,355.0	Coal	AEP	60	01-Jun-15
PSEG	National Park 1	21.0	Kerosene	PSEG	46	01-Jun-15
AEP	Picway 5	95.0	Coal	AEP	60	01-Jun-15
PSEG	Sewaren 6	105.0	Kerosene	PSEG	50	01-Jun-15
AEP	Sporn 1-4	580.0	Coal	AEP	64	01-Jun-15
AEP	Tanners Creek 1-4	982.0	Coal	AEP	60	01-Jun-15
NRG Energy	Shawville 4	175.0	Coal	PENELEC	55	02-Jun-15
NRG Energy	Shawville 3	175.0	Coal	PENELEC	56	07-Jun-15
NRG Energy	Shawville 1	122.0	Coal	PENELEC	61	12-Jun-15
NRG Energy	Shawville 2	125.0	Coal	PENELEC	61	14-Jun-15
Portsmouth Genco	Lake Kingman	115.0	Coal	Dominion	27	19-Jun-15
AES Corporation	AES Beaver Valley	124.0	Coal	DLCO	28	01-Sep-15
First Energy	Burger EMD	6.3	Diesel	ATSI	43	18-Sep-15
Total		9,847.3				

Generation Mix

As of September 30, 2015, PJM had an installed capacity of 185,656.0 MW (Table 12-11). This measure differs from Capacity Market installed capacity because it includes energy-only units, excludes all external units, and uses non-derated values for solar and wind resources.

Figure 12-2 and Table 12-12 show the age of PJM generators by unit type. Units older than 40 years comprise 66,781.6 MW, or 36.0 percent, of the total capacity of 185,656.0 MW.

Table 12-11 Existing PJM capacity: At September 30, 2015 (By zone and unit type (MW))[14]

Zone	CC	CT	Diesel	Fuel Cell	Hydroelectric	Nuclear	Solar	Steam	Storage	Wind	Total
AECO	901.9	507.7	22.6	0.0	0.0	0.0	41.7	815.9	0.0	7.5	2,297.3
AEP	4,900.0	3,682.2	77.1	0.0	1,071.9	2,071.0	0.0	18,897.8	4.0	1,953.2	32,657.2
AP	1,129.0	1,214.9	47.9	0.0	86.0	0.0	36.1	5,409.0	27.4	1,058.5	9,008.8
ATSI	685.0	1,617.4	74.0	0.0	0.0	2,134.0	0.0	5,813.0	0.0	0.0	10,323.4
BGE	0.0	840.0	18.4	0.0	0.0	1,716.0	0.0	2,995.5	0.0	0.0	5,569.9
ComEd	3,146.1	7,244.0	93.8	0.0	0.0	10,473.5	9.0	5,166.1	76.0	2,431.9	28,640.4
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	0.0	0.0	0.0	0.0	0.0	3,730.0	2.0	0.0	4,433.2
DLCO	244.0	15.0	0.0	0.0	6.3	1,777.0	0.0	784.0	0.0	0.0	2,826.3
Dominion	5,493.6	3,874.8	153.8	0.0	3,589.3	3,581.3	22.7	7,890.0	0.0	0.0	24,605.5
DPL	1,498.5	1,820.4	96.1	30.0	0.0	0.0	4.0	1,620.0	0.0	0.0	5,069.0
EKPC	0.0	774.0	0.0	0.0	70.0	0.0	0.0	1,882.0	0.0	0.0	2,726.0
JCPL	1,692.5	763.1	19.9	0.0	400.0	614.5	104.3	10.0	0.0	0.0	3,604.3
Met-Ed	2,111.0	406.5	41.4	0.0	19.0	805.0	0.0	200.0	0.0	0.0	3,582.9
PECO	3,209.0	836.0	2.9	0.0	1,642.0	4,546.8	3.0	979.1	1.0	0.0	11,219.8
PENELEC	0.0	407.5	52.2	0.0	512.8	0.0	0.0	6,793.5	0.0	930.9	8,696.9
Pepco	230.0	1,091.7	9.9	0.0	0.0	0.0	0.0	3,649.1	0.0	0.0	4,980.7
PPL	1,807.9	616.2	55.5	0.0	706.6	2,520.0	15.0	5,169.9	20.0	219.7	11,130.8
PSEG	3,091.3	1,132.0	11.1	0.0	5.0	3,493.0	134.0	2,050.1	2.0	0.0	9,918.5
RECO	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	30,187.0	28,865.9	824.1	30.0	8,108.9	33,732.1	370.9	76,763.0	172.4	6,601.7	185,656.0

Table 12-12 PJM capacity (MW) by age (years): At September 30, 2015

Age (years)	CC	CT	Diesel	Fuel Cell	Hydroelectric	Nuclear	Solar	Steam	Storage	Wind	Total
Less than 20	25,808.5	21,457.0	563.4	30.0	189.6	0.0	370.9	4,601.9	172.4	6,601.7	59,795.4
20 to 40	3,936.5	2,913.9	88.8	0.0	3,557.2	22,893.9	0.0	25,688.7	0.0	0.0	59,079.0
40 to 60	442.0	4,495.0	169.9	0.0	3,010.0	10,838.2	0.0	44,835.9	0.0	0.0	63,791.0
More than 60	0.0	0.0	2.0	0.0	1,352.1	0.0	0.0	1,636.5	0.0	0.0	2,990.6
Total	30,187.0	28,865.9	824.1	30.0	8,108.9	33,732.1	370.9	76,763.0	172.4	6,601.7	185,656.0

14 The capacity described in this section refers to all non-derated installed capacity in PJM, regardless of whether the capacity entered the RPM auction. This table previously included external units.

Figure 12-2 PJM capacity (MW) by age (years): At September 30, 2015

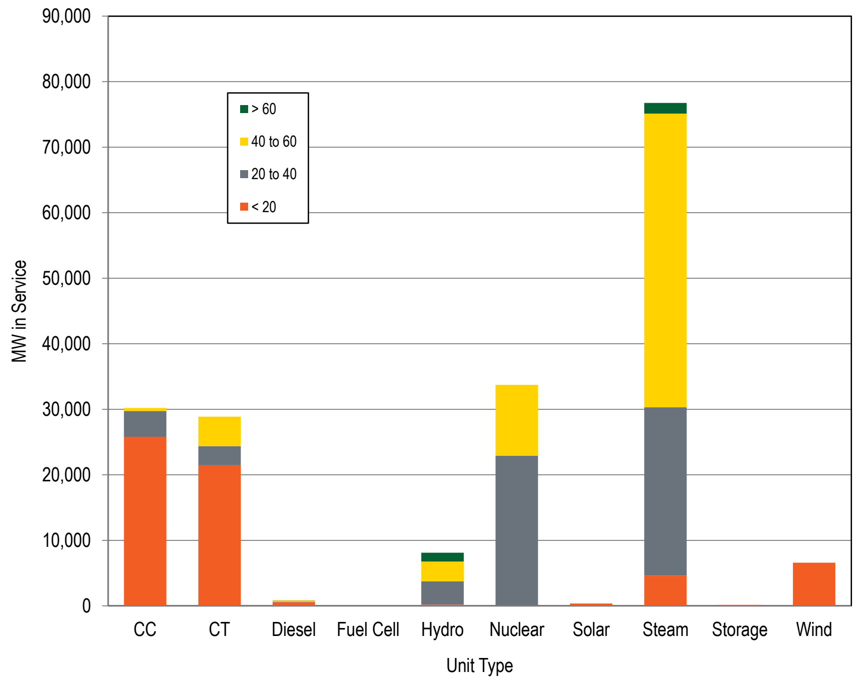


Table 12-13 shows the effect that expected retirements and new generation in the queues would have on the existing generation mix five years from now. Even though 66,781.6 MW of the total capacity are more than 40 years old, only 3,264.7 MW of these are planned to retire within the next five years. The expected role of gas-fired generation depends on projects in the queues and retirement of coal-fired generation. Existing capacity is 41.4 percent steam, which will be reduced to 31.0 percent by 2020 as a result of the addition of 41,848.6 MW of planned CC capacity. The percentage of CC capacity would increase from 16.3 percent to 29.7 percent of total capacity in PJM in 2020.

Table 12-13 Expected capacity (MW) in five years: as of September 30, 2015[15]

LDA	Unit Type	Current Generator Capacity	Percent of Area Total	Planned Additions	Planned Retirements	Estimated Capacity in 5 Years	Percent of Area Total
EMAAC	Combined Cycle	10,393.2	32.4%	10,237.9	0.0	20,631.1	46.4%
	Combustion Turbine	5,059.2	15.8%	835.5	0.0	5,894.7	13.3%
	Diesel	152.6	0.5%	26.0	8.0	170.6	0.4%
	Fuel Cell	30.0	0.1%	0.0	0.0	30.0	0.1%
	Hydroelectric	2,047.0	6.4%	0.0	0.0	2,047.0	4.6%
	Nuclear	8,654.3	27.0%	10.0	614.5	8,049.8	18.1%
	Solar	287.0	0.9%	1,170.4	0.0	1,457.4	3.3%
	Steam	5,475.1	17.1%	0.0	695.8	4,779.3	10.8%
	Storage	3.0	0.0%	262.0	0.0	265.0	0.6%
	Wind	7.5	0.0%	1,122.6	0.0	1,130.1	2.5%
	Total	32,108.9	100.0%	13,664.4	1,318.3	44,455.0	100.0%
SWMAAC	Combined Cycle	230.0	2.2%	2,725.6	0.0	2,955.6	24.7%
	Combustion Turbine	1,931.7	18.3%	0.0	51.0	1,880.7	15.7%
	Diesel	28.3	0.3%	30.3	0.0	58.6	0.5%
	Nuclear	1,716.0	16.3%	0.0	0.0	1,716.0	14.3%
	Steam	6,644.6	63.0%	132.0	1,413.0	5,363.6	44.8%
	Total	10,550.6	100.0%	2,887.9	1,464.0	11,974.5	100.0%
WMAAC	Combined Cycle	3,918.9	16.7%	11,284.0	0.0	15,202.9	34.2%
	Combustion Turbine	1,430.2	6.1%	678.9	0.0	2,109.1	4.7%
	Diesel	149.1	0.6%	186.7	0.0	335.8	0.8%
	Hydroelectric	1,238.4	5.3%	40.0	0.0	1,278.4	2.9%
	Nuclear	3,325.0	14.2%	16.8	0.0	3,341.8	7.5%
	Solar	15.0	0.1%	145.5	0.0	160.5	0.4%
	Steam	12,163.4	52.0%	417.0	0.0	12,580.4	28.3%
	Storage	20.0	0.1%	98.4	0.0	118.4	0.3%
	Wind	1,150.6	4.9%	991.8	10.4	2,132.0	4.8%
	Total	23,410.6	100.0%	13,859.1	10.4	37,259.2	100.0%
RTO	Combined Cycle	15,644.9	13.1%	27,325.5	0.0	42,970.4	26.0%
	Combustion Turbine	20,444.8	17.1%	655.1	0.0	21,099.9	12.8%
	Diesel	494.1	0.4%	234.7	0.0	728.8	0.4%
	Hydroelectric	4,823.5	4.0%	226.9	0.0	5,050.4	3.1%
	Nuclear	20,036.8	16.8%	102.0	0.0	20,138.8	12.2%
	Solar	69.0	0.1%	2,244.1	0.0	2,313.1	1.4%
	Steam	52,479.9	43.9%	2,105.2	472.0	54,113.1	32.8%
	Storage	149.4	0.1%	401.6	0.0	551.0	0.3%
	Wind	5,443.6	4.6%	12,632.7	0.0	18,076.3	11.0%
	Total	119,586.0	100.0%	45,927.8	472.0	165,041.8	100.0%
Total		185,656.0		76,339.2	3,264.7	258,730.5	

15 Percentages shown in Table 12-13 are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

Generation and Transmission Interconnection Planning Process

PJM made changes to the queue process in May 2012.[16] 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. PJM staff also noted that most queue projects are submitted in the last week of the six-month queues, contributing to the study backlog because of the time it takes to resolve deficiencies and enter project parameters into the planning models.[17] The Earlier Queue Submittal Task Force (EQSTF) was established in August 2015 to address the issue.[18]

Interconnection Study Phase

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 12-14 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 12-14 PJM generation planning process

Milestone Completed	Number of Projects	Percent of Total Projects	Average Days	Maximum Days
Not Started	73	12.1%	553	1,800
Feasibility Study	116	19.2%	772	2,555
Impact Study	113	18.7%	1,148	3,351
Facilities Study	23	3.8%	1,880	3,890
Interconnection Service Agreement (ISA)	13	2.2%	865	1,858
Wholesale Market Participation Agreement (WMPA)	1	0.2%	519	519
Construction Service Agreement (CSA)	4	0.7%	822	1,842
Under Construction	195	32.3%	1,782	6,380
Suspended	66	10.9%	2,107	4,149
Total	604	100.0%		

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.[19] 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 12-15 and Table 12-16.

Table 12-16 shows the milestone status when projects were withdrawn, for all withdrawn projects. Of the projects withdrawn, 48.3 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.[20,21] As expected, withdrawing at or beyond this point is uncommon; only 206 projects, or 12.6 percent, of all projects withdrawn were withdrawn after reaching this milestone.

Table 12-15 Last milestone completed at time of withdrawal: January 1, 1997 through September 30, 2015

Milestone Completed	Projects Withdrawn	Percent
Never Started	176	10.7%
Feasibility Study	617	37.6%
System Impact Study	536	32.7%
Facilities Study	106	6.5%
Interconnection Service Agreement (ISA)	37	2.3%
Wholesale Market Participation Agreement (WMPA)	115	7.0%
Construction Service Agreement (CSA) or beyond	54	3.3%
Total	1,641	100.0%

Disregarding projects still active or under construction, Table 12-16 shows, by MW, the rate at which projects drop out of the queue as they move through the process. Out of 264,381.0 MW that entered the queue, 33,328.5 went into service, while the remaining 244,028.0 MW withdrew at some point. Of the

16 See letter from PJM to Secretary Kimberly Bose, Docket No. ER12-1177-000, <http://www.pjm.com/~/media/documents/ferc/2012-filings/20120229-er12-1177-000.ashx>.
17 See presentation by Dave Egan to the Planning Committee PJM, at <http://www.pjm.com/~/media/committees-groups/committees/pc/20150611/20150611-item-09-queue-status-update.ashx>
18 See Earlier Queue Submittal Task Force at <http://www.pjm.com/committees-and-groups/task-forces/eqstf.aspx>

19 See PJM Manual 14B. "PJM Region Transmission Planning Process," Revision 30 (February 26, 2015), p.70.
20 "Generators planning to connect to the local distribution systems at locations that are not under FERC jurisdiction and wish to participate in PJM's market need to execute a PJM Wholesale Market Participation Agreement (WMPA)..." instead of an ISA. See PJM Manual 14C. "Generation and Transmission Interconnection Facility Construction," Revision 08 (December 20, 2012), p.8.
21 See PJM Manual 14C. "Generation and Transmission Interconnection Facility Construction," Revision 08 (December 20, 2012), p.22.

withdrawals, 53.9 percent happened after the feasibility study was completed, before proceeding to the next milestone.

Table 12-16 Completed (withdrawn or in service) queue MW: January 1, 1997 through September 30, 2015

Milestone Completed	MW in Queue	Percent of Total in Queue	MW Withdrawn	Percent of Total Withdrawn
Enter Queue	264,381.0	100.0%	20,353.0	8.8%
Feasibility Study	244,028.0	92.3%	124,582.6	53.9%
System Impact Study	119,445.3	45.2%	48,075.2	20.8%
Facility Study	71,370.2	27.0%	23,403.9	10.1%
ISA/WMPA	47,966.3	18.1%	8,177.7	3.5%
CSA	39,788.7	15.0%	6,460.2	2.8%
In Service	33,328.5	12.6%	0.0	0.0%

Table 12-17 and Table 12-18 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 924 days, or 2.5 years, between entering a queue and going into service. Nuclear and wind projects tend to take longer to go into service averaging 1,419.6 and 1,393.1 days. The average time to go into service for all other fuel types is 710 days. For withdrawn projects, there is an average time of 656 days between entering a queue and withdrawing.

Table 12-17 Average project queue times (days): At June 30, 2015

Status	Average (Days)	Standard Deviation	Minimum	Maximum
Active	927	698	38	3,890
In-Service	924	679	1	4,024
Suspended	2,107	781	601	4,149
Under Construction	1,782	906	197	6,380
Withdrawn	656	657	6	4,249

Table 12-18 presents information on the time in the stages of the queue for those projects not yet in service. Of the 604 projects in the queue as of September 30, 2015, 116 had a completed feasibility study and 195 were under construction.

Table 12-18 PJM generation planning summary: At September 30, 2015

Milestone Completed	Number of Projects	Percent of Total Projects	Average Days	Maximum Days
Not Started	73	12.1%	553	1,800
Feasibility Study	116	19.2%	772	2,555
Impact Study	113	18.7%	1,148	3,351
Facilities Study	23	3.8%	1,880	3,890
Interconnection Service Agreement (ISA)	13	2.2%	865	1,858
Wholesale Market Participation Agreement (WMPA)	1	0.2%	519	519
Construction Service Agreement (CSA)	4	0.7%	822	1,842
Under Construction	195	32.3%	1,782	6,380
Suspended	66	10.9%	2,107	4,149
Total	604	100.0%		

The time it takes to complete a study depends on the backlog and the number of projects in the queue. The time it takes to complete a study does not necessarily depend on the size of the project. Renewable projects (solar, hydro, storage, biomass, wind) account for 62.1 percent of the total number of projects in the queue but only 24.7 percent of the non-derated MW(Table 12-19).

Table 12-19 Queue details by fuel group: At September 30, 2015

Fuel Group	Number of Projects	Percent of Projects	MW	Percent MW
Nuclear	5	0.8%	1,722.8	2.2%
Renewable	375	62.1%	19,667.0	24.7%
Traditional	224	37.1%	58,214.0	73.1%
Total	604	100.0%	79,603.8	100.0%

Role of Transmission Owners in Transmission Planning Study Phase

According to PJM Manual 14A, PJM, in coordination with the TOs, conducts the feasibility, system impact and facilities studies for every interconnection queue project. It is clear that the TOs perform the studies.[22] The coordination begins with PJM identifying transmission issues resulting from the generation projects. The TOs perform the studies and provide the mitigation requirements for each issue. A facilities study is required only for new generation and

22 See PJM, OATT, Part VI, § 210

significant generation additions and is the study in which the TO is most involved. For a facilities study, the interconnected TO (ITO), as well as any other affected TOs, is required to conduct their own facilities study and provide a summary and results to PJM. PJM compiles these results, along with inputs from the developer, into PJM's models to confirm that the TOs' defined upgrades will resolve the issue. PJM writes the final facilities report, which includes the inputs, a description of the issues to be resolved, and the findings of all contributing TOs.[23]

Of 604 active projects analyzed, the developer and TO are part of the same company for 45 of the projects, or 11,097.4 MW of a total 79,603.9 MW, 13.9 percent of the MW. Where the TO is a vertically integrated company that also owns generation, there is a potential conflict of interest when the TO evaluates the interconnection requirements of new generation which is part of the same company. There is also a potential conflict of interest when the transmission owner evaluates the interconnection requirements of new generation which is a competitor to the generation of its parent company.

Table 12-20 is a summary of the number of projects and total MW, by transmission owner parent company, which identifies the number of projects for which the developer and transmission owner are part of the same company. The Dominion Zone has eight related projects which account for 5,867.3 MW, 56.0 percent of the total MW currently in the queue in the Dominion Zone. Renewable projects comprise 3,415.0 MW, 74.1 percent, of unrelated projects in the queue in the Dominion Zone. In contrast, the AEP Zone has 12 related projects, but they account for only 2.8 percent of its total MW currently in the queue.

Table 12-20 Summary of project developer relationship to transmission owner

	Number of Projects			Total MW		
Parent Company	Related	Unrelated	Percent Related	Related	Unrelated	Percent Related
AEP	12	69	14.8%	370.7	12,862.8	2.8%
AES	2	5	28.6%	32.0	325.3	9.0%
DLCO	0	1	0.0%	0.0	205.0	0.0%
Dominion	8	57	12.3%	5,867.3	4,605.0	56.0%
Duke	2	7	22.2%	52.0	772.4	6.3%
Exelon	8	92	8.0%	2,270.0	11,011.8	17.1%
First Energy	2	199	1.0%	1,736.0	22,170.3	7.3%
Pepco	0	77	0.0%	0.0	6,784.3	0.0%
PPL	0	28	0.0%	0.0	6,820.4	0.0%
PSEG	11	24	31.4%	769.4	2,949.2	20.7%
Total	45	559	7.5%	11,097.4	68,506.5	13.9%

These projects are shown by fuel type in Table 12-21. Natural gas generators comprise 69.9 percent of the total related MW in this table. Developers of coal and nuclear projects are almost entirely related to the TO, with 95.3 percent and 99.0 percent of MW. Developers are related to the TO for 13.3 percent of the natural gas project MW in the queue and 12.7 percent of the hydro project MW. All other fuel types projects have no more than 1.1 percent of MW in development related to the TO.

23 See PJM. "Manual 14A, "Generation and Transmission Interconnection Process," Revision 17, (January 22, 2015),<http://www.pjm.com/documents/manuals.aspx>

Table 12-21 Developer-transmission owner relationship by fuel type

				MW by Fuel Type											
Parent Company	Transmission Owner	Related to Developer	Number of Projects	Biomass	Coal	Diesel	Hydro	Landfill Gas	Natural Gas	Nuclear	Oil	Solar	Storage	Wind	Total MW
AEP	AEP	Related	12		83.0		34.0		137.0	102.0		14.7			370.7
		Unrelated	69	45.0	92.0			15.8	6,019.0			87.0	62.0	6,542.0	12,862.8
AES	DAY	Related	2		12.0								20.0		32.0
		Unrelated	5	1.9								23.4		300.0	325.3
DLCO	DLCO	Unrelated	1						205.0						205.0
Dominion	Dominion	Related	8						4,261.3	1,594.0				12.0	5,867.3
		Unrelated	57	62.5				2.0	1,190.0			1,760.4	130.0	1,460.1	4,605.0
Duke	DEOK	Related	2		50.0								2.0		52.0
		Unrelated	7				112.0	6.4	513.0			125.0	16.0		772.4
Exelon	BGE	Related	1									20.0			20.0
		Unrelated	28	157.0			0.4	4.0	1.3			3.1	20.2		186.0
	ComEd	Unrelated	53				22.7	39.9	5,817.8			10.0	124.6	3,387.0	9,402.0
	PECO	Related	7						2,200.0	10.0			40.0		2,250.0
		Unrelated	11			6.1		3.2	1,414.5						1,423.8
First Energy	APS	Related	2		1,710.0				26.0						1,736.0
		Unrelated	60				58.2	17.2	5,920.3			219.6	51.0	663.6	6,929.9
	ATSI	Unrelated	12					1.7	4,091.8					518.0	4,611.5
	JCPL	Unrelated	79						2,869.6			540.6	180.0		3,590.2
	Met-Ed	Unrelated	8						1,336.6	16.8	401.0	3.0			1,757.4
	PENELEC	Unrelated	40				40.0		4,686.1			13.5	68.4	473.3	5,281.3
Pepco	AECO	Unrelated	20						1,578.5			49.2	20.0	373.0	2,020.7
	DPL	Unrelated	49					2.0	839.0			425.4	22.0	749.6	2,038.0
	Pepco	Unrelated	8						2,725.6						2,725.6
PPL	PPL	Unrelated	28	16.0				5.0	6,234.9			16.0	30.0	518.5	6,820.4
PSEG	PSEG	Related	11						766.0			3.4			769.4
		Unrelated	24						2,797.5			151.7			2,949.2
Total		Related	45	0	1,855	0	34	0	7,390	1,706	0	38	62	12	11,097.4
		Unrelated	559	282	92	6	233	97	48,240	17	401	3,428	724	14,985	68,506.5

Regional Transmission Expansion Plan (RTEP)

PJM's Transmission Expansion Advisory Committee (TEAC), made up of PJM staff, is responsible for the Regional Transmission Expansion Plan (RTEP).[24] Transmission upgrades can be divided into three categories: network, supplemental, and baseline. Network upgrades are initiated by generation queue projects and are funded by the developers of the generation projects. Supplemental upgrades are initiated and funded by the TOs. Baseline upgrades are initiated by the TEAC to resolve reliability criteria violations not addressed in other ways. The costs of the baseline projects are allocated proportionally to all TOs who will benefit from the upgrade. Per FERC Order 1000, the TEAC solicits proposals via fixed proposal windows to address these needs. The TEAC evaluates the proposals and recommends proposals to the PJM Board of Managers for approval. Retired generators are included in this analysis for one year after their retirement to reflect the ownership of CIRs.

24 See PJM Manual 14B. "PJM Region Transmission Planning Process," Revision 30 (February 26, 2015), Section 2, p.14

On February 17, 2015, baseline projects with an estimated cost of $551.4 million were presented to and approved by the Board. New projects account for $474.4 million of this amount and adjustments to previously approved baseline projects were $77.0 million.[25] Table 12-22 shows a summary of the new baseline upgrade costs for each TO.

Table 12-22 2015 Board approved new baseline upgrades by transmission owner

Transmission Owner	Baseline Upgrades ($ million)
AEP	312.6
APS	1.7
ComEd	0.7
Dominion	118.0
EKPC	2.1
JCPL	14.8
Met-Ed	1.0
PECO	1.5
PENELEC	5.8
PPL	0.8
PSEG	15.6
Total	474.4

The 2015 RTEP Proposal Window 1 opened on June 19, 2015, and closed on July 20, 2015. The scope for these proposals includes baseline N-1, generation deliverability and common mode outage, N-1-1, and load deliverability.[26] PJM received 90 proposals, comprising 26 upgrades and 64 greenfield projects and addressing 292 flow gates in six target zones. PJM staff are currently evaluating these proposals and expect to make a recommendation in October 2015.[27]

The 2015 RTEP Proposal Window 2 opened on August 5, 2015, and closed on September 4, 2015. The scope for these proposals includes light load analysis and 2020 TO criteria.[28]

25 See PJM Staff Whitepaper presented to the TEAC at <http://www.pjm.com/~/media/committees-groups/committees/teac/20150409/20150409-february-2015-board-approval-of-rtep-whitepaper.ashx>

26 See "PJM RTEP – 2015 RTEP Proposal Window #1 Problem Statement & Requirements Document," June 19, 2015 at <http://www.pjm.com/~/media/planning/rtep-dev/expan-plan-process/ferc-order-1000/rtep-proposal-windows/2015-rtep-window-1-problem-statement-and-requirements.ashx>

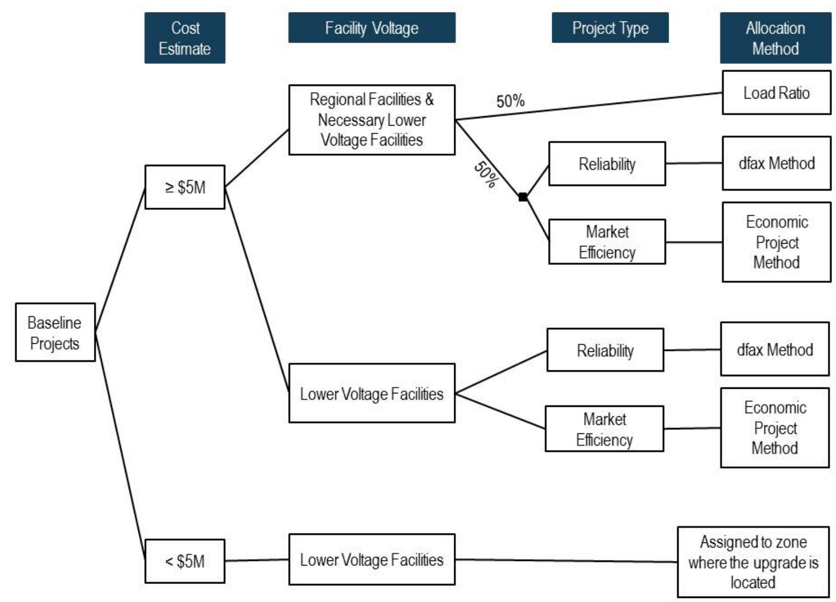
27 See TEAC webcast of September 1, 2015 at <http://mediastream.pjm.com/2015/0901/teac/2015-rtep-proposal/index.htm>

28 See "PJM RTEP – 2015 RTEP Proposal Window #1 Problem Statement & Requirements Document," August 5, 2015 at <http://www.pjm.com/~/media/planning/rtep-dev/expan-plan-process/ferc-order-1000/rtep-proposal-windows/2015-rtep-window-2-problem-statement-and-requirements-document.ashx>

Cost Estimates and Allocations

On October 25, 2012, Schedule 12 of the tariff and Schedule 6 of the OA were changed to address Order No. 1000 reforms to the cost allocation requirements for local and regional transmission planning projects that had been defined in FERC Order No. 890. The new approach was applied for the first time to the 2013 RTEP. Prior to these changes, costs for a portion of reliability projects were allocated on violation-based dfax values, focusing on the contributions that load made to the violation. The new solution based dfax looks at the relative use of the new facility.[29] The allocation rules are summarized in Figure 12-1.

Figure 12-3 RTEP cost allocation rules



29 See *PJM Interconnection, L.L.C.*, 142 FERC ¶ 61,214 (2013)

Artificial Island Update

Artificial Island is an area in the PSEG Zone in southern New Jersey that includes nuclear units at Salem and at Hope Creek. On April 29, 2013, PJM issued a request for proposal (RFP), seeking technical solutions to improve stability issues, operational performance under a range of anticipated system conditions, and the elimination of potential planning criteria violations in this area. PJM received 26 individual proposals from seven entities, including proposals from the incumbent transmission owner, PSEG, and from non-incumbents. On July 30, 2105, the PJM Board of Managers accepted PJM's recommendation to assign the project to LS Power, a non-incumbent, PSEG, and PHI with a total cost estimate between $263M and $283M.[30] Table 12-23 shows the details of the project allocation.

Table 12-23 Artificial Island recommended work and cost allocation

Project Task	Designated Developer	Cost Estimate ($ million)	Primary Allocation (percent)
230kV transmission line under the Delaware River from Salem to a new substation near the 230kV transmission RoW in Delaware utilizing HDD under the river	LS Power	146.0 (cost cap)	DPL - 99.99%
Associated substation work at Salem	PSEG	61.0-74.0	DPL - 99.99%
Associated work on the 230kV RoW	PHI	0.0	NA
SVC at New Freedom	PSEG	31.0-38.0	DPL - 51.21%
OPGW upgrades designated to PSEG and PHI & Artificial Island GSU tap settings upgrade	PSEG	25.0	DPL - 51.21%
Total		263.0-283.0	

PJM received comments from PSEG & PSEG Nuclear, contesting the selection of LS Power for the construction of a 230kV line over the PSEG proposal. They argued that the PSEG proposal was inappropriately modified, resulting in a higher cost and a lower score and that several performance factors, including stability, installation complexity, long term maintenance and operational costs, and operational complexity were excluded. PSEG also argued that LS Power's cost cap is misleading and was misinterpreted by PJM staff to be more robust than it actually is. Atlantic Grid Holdings also questioned the robustness of the recommended design. On July 14, 2015, PSEG submitted an adjusted cost cap for their proposal, appealing to PJM to change their recommendation on the basis that their proposal is now even more superior to LS Power's.[31]

The inclusion of a cost cap in some of the offers and the inclusion of a cost cap in the decision criteria is an important step in the development of meaningful competition to build transmission projects. Such cost caps should include minimum exceptions and be enforceable.

PJM received objections to the allocation of 99.9 percent of the costs for the 230kV line portion of the Artificial Island project to DPL, based on the new dfax method, including those from the Delaware Public Service Commission (DE PSC), Delaware Division of the Public Advocate, Old Dominion Electric Cooperative (ODEC), the Maryland Public Service Commission (MD PSC), Easton Utilities, and Delaware Governor Jack Markell.

ConEdison and Linden VFT

A FERC order issued on September 16, 2010 approved a settlement between PJM and Consolidated Edison (ConEd) that redefined the terms of an agreement between ConEd and PJM to provide power to New York City that had been in place since the 1970s. Part of the settlement included an agreement by both parties that ConEd would be subject to PJM RTEP costs, from which they had been previously exempt.[32] The RTEP Baseline Upgrade filings, ER14-972-000 on January 10, 2014, resulted in approximately $1.5 billion in additional baseline transmission enhancements and expansions, of which ConEd was allocated approximately $631 million.[33] PJM submitted these projects as amendments to Schedule 12 of the tariff on January 10, 2014.[34]

On February 10, 2014, ConEd filed a protest to the cost allocation proposal.[35] ConEd asserted that the cost allocation proposal is not permitted under the service agreement for transmission service under the PJM Tariff and related

30 See letter from Terry Boston concerning the Artificial Island Project at <http://www.pjm.com/~/media/documents/reports/board-statement-on-artificial-island-project.ashx>

31 See responses to PJM at <http://www.pjm.com/about-pjm/who-we-are/pjm-board/public-disclosures.aspx>

32 132 FERC ¶ 61,221 p.8 (2010).

33 See Transmission Expansion Advisory Committee (TEAC) Recommendations to the PJM Board" at <http://www.pjm.com/~/media/committees-groups/committees/teac/20131211/20131211-december-2013-pjm-board-approval-of-rtep-whitepaper.ashx>

34 See *PJM Interconnection L.L.C.* Docket No. ER14-972-000 (March 7, 2014)

35 See *Consolidated Edison Company of New York, Inc.* Docket No. ER14-972-000 (February 10, 2014).

settlement agreement, and that PJM's allocation of costs of the PSE&G upgrade to the ConEd Zone is unjust and unreasonable. On March 7, 2014, PJM argued that the filed and approved RTEP cost allocation process was followed, and that ConEd's cost assignment responsibilities were addressed by the settlement agreement and Schedule 12 of the PJM Tariff.[36] ConEd filed a complaint with FERC on November 7, 2014.[37] Linden VFT filed a complaint on May 22, 2015.[38]

The allocations in dispute were a result of the new solution based dfax method of cost allocation. A summary of the disputed cost allocations is shown in Table 12-24. Both complain that the allocations violated Schedule 12 of the tariff and Schedule 6 of the PJM Operating Agreement, which address unreasonable cost allocations.

Table 12-24 ConEd and Linden disputed cost allocation summary

				Allocation ($M)					Allocation (%)				
Upgrade ID	Cost estimate ($M)	Dfax	Load Ratio	ConEd	Linden (ECP)	HTP	PSEG	Other	ConEd	Linden (ECP)	HTP	PSEG	Other
Edison Rebuild	46.0												
dfax Method		46.0		0.0	29.2	16.8	0.0	0.0	0.0%	63.5%	36.5%	0.0%	0.0%
Load Ratio			0.0	0.0	0.0	0.0	0.0	0.0	0.0%	0.0%	0.0%	0.0%	0.0%
Sewaren Project	101.0												
dfax Method		101.0		51.3	49.7	0.0	0.0	0.0	50.8%	49.2%	0.0%	0.0%	0.0%
Load Ratio			0.0	0.0	0.0	0.0	0.0	0.0	0.0%	0.0%	0.0%	0.0%	0.0%
Bergen-Linden Corridor (PSEG projects)	1,180.3												
dfax Method		785.0		629.1	12.6	68.5	72.7	2.1	80.1%	1.6%	8.7%	9.3%	0.3%
Load Ratio			395.4	2.3	0.8	0.8	23.6	367.9	0.6%	0.2%	0.2%	6.0%	93.1%
Total	1,327.3	932.0	395.4	682.7	92.3	86.1	96.3	370.0	51.4%	7.0%	6.5%	7.3%	27.9%

Schedule 12 of the tariff states "If Transmission Provider determines in its reasonable engineering judgment that, as a result of applying the provisions of this Section (b)(iii), the dfax analysis cannot be performed or that the results of such dfax analysis are objectively unreasonable, the Transmission Provider may use an appropriate substitute proxy for the Required Transmission Enhancement in conducting the dfax analysis." Schedule 6 of the PJM Operating Agreement requires PJM to avoid an allocation of unreasonable costs in the RTEP process.[39] [40] Order 1000 states that "costs must be allocated in a way that is roughly commensurate with benefits."[41]

ConEd argued that the cost allocation is "objectively unreasonable" and requested "an appropriate substitute proxy." ConEd's complaint was not that the solution based dfax method was necessarily faulty, but that the assumptions and inputs that PJM used to model ConEd were inaccurate and resulted in an over allocation to ConEd, Linden VFT, and Hudson Transmission Partners (HTP), and an under allocation to PSEG. PJM responded.[42]

FERC ruled on ConEd's complaint on June 18, 2015. FERC accepted the PJM allocation and found that the dfax method, as applied, was not faulty.[43] On July 20, 2015, ConEd, Linden VFT, and the New York Public Service Commission requested rehearing on the grounds that PJM and the TOs failed to address or rebut the claim that benefits do not match allocation.[44]

36 See *PJM Interconnection L.L.C.* Docket No. ER14-972-000 (January 10, 2014).
37 See "ConEd RTEP Complaint," Docket No. E15-18-000 (November 7, 2014)
38 See "Complaint and Request for Fast Track Processing of Linden VFT,LLC," Docket No.EL15-67-000 (May 22, 2015)

39 See PJM, Intra-PJM Tariffs, OATT, Schedule 12 § (b)(iii)(G)
40 See PJM Operating Agreement, § 1.4(d)(ii)
41 See FERC Order 1000-B, §3, Paragraph 66
42 See PJM, Intra-PJM Tariffs, OATT, Schedule 12 § (b)(iii)(I)
43 See FERC Order issued June 18, 2015, Docket No. ER14-972-002, <http://www.pjm.com/~/media/documents/ferc/2015-orders/20150618-er14-972-002.ashx>.
44 See "Order Granting Rehearing for Further Consideration re Consolidated Edison Company of New York, Inc v. PJM Interconnection, L.L.C et al.", Docket no. EL15-18-000 (August 10, 2015).

TranSource

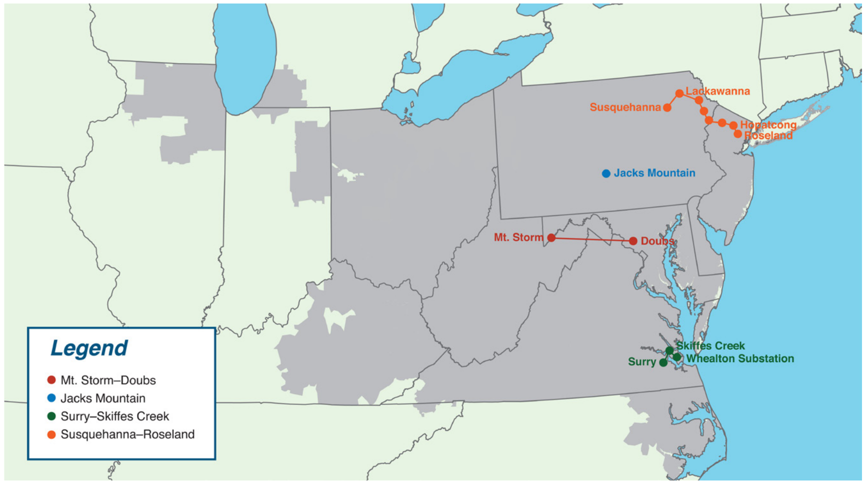
TranSource LLC stated, in a complaint filed on June 23, 2015, that PJM is not being transparent with respect to the development of its cost estimates in the System Impact Study (SIS) phase of three TranSource transmission projects. These projects were intended to be used to procure incremental auction revenue rights (IARR). TranSource seeks an order directing PJM to provide data and working papers related to the SIS sufficient to fully evaluate the basis of cost estimates that TranSource considers excessive. PJM responded that it has provided all work papers relevant to the SIS and objects to the complaint on procedural grounds.[45] On September 24, 2015, the Commission issued an order establishing hearing and settlement judge procedures.[46] The MMU is participating in this process.

Backbone Facilities

PJM backbone projects are a subset of baseline upgrade projects that have been given the informal designation of backbone due to their relative significance. Backbone upgrades are on the extra high voltage (EHV) system and resolve a wide range of reliability criteria violations and market congestion issues. The current backbone projects are Mount Storm-Doubs, Jacks Mountain, Susquehanna-Roseland, and Surry Skiffes Creek 500kV. Figure 12-4 shows the location of these four projects.

45 See Motion to Dismiss Complaint and Answer to Complaint Submitted on Behalf of PJM Interconnection, L.L.C., Docket No. EL15-79-000 (July 10, 2015).
46 152 FERC ¶ 61,229.

Figure 12-4 PJM Backbone Projects



The Mount Storm-Doubs transmission line, which serves West Virginia, Virginia, and Maryland, was originally built in 1966. The structures and equipment are approaching the end of their expected service life and require replacement to ensure reliability. The first two phases, the line rebuild and the energizing of the Mount Storm switchyard, are complete. Construction plans for Phase 3, consisting of additional upgrades to the Mount Storm switchyard, are under development. Completion of this phase is expected by the end of 2015.[47]

The Jacks Mountain project is required to resolve voltage problems for load deliverability starting June 1, 2017. Jacks Mountain will be a new 500kV substation connected to the existing Conemaugh-Juniata and Keystone-Juniata 500kV circuits. This project is currently in the engineering and design phase. Transmission foundations are planned for fall 2015. Below grade construction of the sub-station is scheduled to be completed by September 2016, and above grade, relay/control construction, is planned for October 2016-June 2017.[48]

47 See Dominion "*Mt. Storm-Doubs*," which can be accessed at: <http://www.pjm.com/planning/rtep-upgrades-status/backbone-status/mount-storm-doubs.aspx>.
48 See "Jacks Mountain," which can be accessed at: <http://www.pjm.com/planning/rtep-upgrades-status/backbone-status/jacks-mountain.aspx>.

The Susquehanna-Roseland project is required to resolve reliability criteria violations starting June 1, 2012. Susquehanna-Roseland is a new 101-mile 500 kV transmission line connecting the Susquehanna, Lackawanna, Hopatcong, and Roseland buses. PPL is responsible for the first two legs and PSEG for the third. The Susquehanna-Lackawanna portion went into service on September 23, 2014, and the Lackawanna–Hopatcong portion was energized on May 11, 2015. The Hopatcong – Roseland leg was placed in service on April 1, 2014.[49] This project is now complete.

The Surry Skiffes Creek 500kV was initiated in the fall of 2014 to relieve the overload of the James River Crossing Double Circuit Towerline anticipated to result from the retirement of Chesapeake units 1-4, which occurred in December 2014, and Yorktown 1, which is pending. It will include a new 7.7 mile 500kV line between Surry and Skiffes, a new 20.25 mile 230kV line between Skiffes Creek and Whealton, and a new Skiffes Creek 500/230kV switching station. PJM's required in service date for the 500kv portion was June 1, 2015. This project has been delayed by legal challenges. BASF Corporation raised environmental concerns with the siting and the design. James City County and James River Association (JCC) argued that the switching station is not part of the transmission line and therefore should be subject to local zoning ordinances. In an April 16, 2015, ruling, the Supreme Court of Virginia rejected BASF's claim but agreed with JCC.[50] On April 30, 2015, Dominion filed a petition for rehearing, which was rejected, and the case was remanded to the State Corporation Commission (SCC). The SCC issued an order on June 5, 2015, stressing the need for this project to be completed.[51] Dominion has begun the foundation work on existing transmission lines at James River Bridge and expects to have it completed by the end of 2015. Dominion expects to energize both the 230kV line and the 500kV line by January 31, 2017.[52]

49 See "Susquehanna-Roseland," which can be accessed at: <http://www.pjm.com/planning/rtep-upgrades-status/backbone-status/susquehanna-roseland.aspx>.
50 BASF Corporation v SCC, et al., Record No. 141009 et al.
51 See SCC order, June 5, 2015 at <https://www.dom.com/library/domcom/pdfs/electric-transmission/surry-skiffes-creek/scc-order-060515.pdf>
52 See "Surry-Skiffes Creek 500kV and Skiffes Creek-Whealton 230kV Projects," which can be accessed at: <https://www.dom.com/corporate/what-we-do/electricity/transmission-lines-and-projects/surry-skiffes-creek-500kv-and-skiffes-creek-whealton-230kv-projects>.

Transmission Facility Outages

Scheduling Transmission Facility Outage Requests

PJM designates some transmission facilities as reportable. A transmission facility is reportable 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. 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.[53] 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 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. Table 12-25 shows that 79.2 percent of the requested outages were planned for five days or shorter and 5.4 percent of requested outages were planned for longer than 30 days in the first nine months of 2015. All of the outage data in this section are for outages scheduled to occur in the first nine months of 2014 and 2015, regardless of when they were initially submitted.[54]

Table 12-25 Transmission facility outage request summary by planned duration: January through September of 2014 and 2015

	2014 (Jan - Sep)		2015 (Jan - Sep)	
Planned Duration (Days)	Outage Requests	Percent	Outage Requests	Percent
<=5	11,480	80.4%	11,457	79.2%
>5 & <=30	2,040	14.3%	2,220	15.4%
>30	763	5.3%	781	5.4%
Total	14,283	100.0%	14,458	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, outage planned starting and ending date, and outage planned duration. The received status can be on time, late or past deadline, as defined in Table 12-26.[55] The purpose of

53 See PJM. "Manual 3a: Energy Management System (EMS) Model Updates and Quality Assurance (QA), Revision 9 (January 22, 2015).
54 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.
55 See "PJM. "Manual 3: Transmission Operations," Revision 47A (July 1, 2015), p.58.

the rules 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 on which to base their FTR bids.[56]

Table 12-26 PJM transmission facility outage request received status definition

Planned Duration (Days)	Ticket Submission Date	Received Status
<=5	Before the 1st of the month one month prior to the starting month of the outage	On Time
	After or on the 1st of the month one month prior to the starting month of the outage	Late
	After 8:00AM three days prior to the outage	Past Deadline
> 5 & <=30	Before the 1st of the month six months prior to the starting month of the outage	On Time
	After or on the 1st of the month six months prior to the starting month of the outage	Late
	After 8:00AM three days prior to the outage	Past Deadline
>30	The earlier of either February 1st or the 1st of the month six months prior to the starting month the outage	On Time
	After or on the earlier of either February 1st or the 1st of the month six months prior to the starting month the outage	Late
	After 8:00AM three days prior to the outage	Past Deadline

Table 12-27 shows a summary of requests by received status. In the first nine months of 2015, 49.3 percent of outage requests received were late.

Table 12-27 Transmission facility outage request summary by received status: January through September of 2014 and 2015

	2014 (Jan - Sep)				2015 (Jan - Sep)			
Planned Duration (Days)	On Time	Late	Total	Percent Late	On Time	Late	Total	Percent Late
<=5	5,857	5,623	11,480	49.0%	5,981	5,476	11,457	47.8%
>5 & <=30	1,014	1,026	2,040	50.3%	1,068	1,152	2,220	51.9%
>30	323	440	763	57.7%	283	498	781	63.8%
Total	7,194	7,089	14,283	49.6%	7,332	7,126	14,458	49.3%

56 *See* 97 FERC ¶ 61,010 (October 3, 2001).

Once received, PJM processes outage requests in priority order: emergency transmission outage request, transmission outage requests submitted on time, and transmission submitted late. If two outage requests submitted by different transmission owners are expected to occur during the same period, the outage submitted first is processed first by PJM. If a request has an emergency flag, it has the highest priority and will be approved even if submitted past its deadline after PJM determines that the outage does not result in Emergency Procedures.[57] 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 request that are submitted late and do not cause congestion on the PJM system. PJM retains the right to deny all transmission outage request that are submitted past deadline unless the request is an emergency. Table 12-28 is a summary of outage requests by emergency status. Of all outage requests submitted in the first nine months of 2015, 14.2 percent were for emergency outages.

Table 12-28 Transmission facility outage request summary by emergency: January through September of 2014 and 2015

	2014 (Jan - Sep)				2015 (Jan - Sep)			
Planned Duration (Days)	Emergency	Non Emergency	Total	Percent Emergency	Emergency	Non Emergency	Total	Percent Emergency
<=5	1,829	9,651	11,480	15.9%	1,653	9,804	11,457	14.4%
>5 & <=30	275	1,765	2,040	13.5%	315	1,905	2,220	14.2%
>30	113	650	763	14.8%	85	696	781	10.9%
Total	2,217	12,066	14,283	15.5%	2,053	12,405	14,458	14.2%

After PJM determines that a late request may cause congestion, PJM informs the Transmission Owner of solutions available to eliminate the congestion. If a generator planned or maintenance outage request is contributing to the congestion, PJM can request the Generation Owner to defer the outage. If no solutions are available, PJM may require the Transmission Owner to reschedule or cancel the outage. Table 12-29 is a summary of outage requests by congestion status. Of all outage requests submitted in the first nine months of 2015, 10.0 percent were expected to cause congestion and the percentage of outage requests flagged for congestion is similar across the categories

57 PJM. "Manual 3: Transmission Outages," Revision: 47A (July 1, 2015), p. 67 and p.68.

of planned duration. Of all the outage requests that were expected to cause congestion, 80 requests were denied by PJM in the first nine months of 2015 (Table 12-31).

Table 12-29 Transmission facility outage request summary by congestion: January through September of 2014 and 2015

	2014 (Jan - Sep)				2015 (Jan - Sep)			
Planned Duration (Days)	Congestion Expected	No Congestion Expected	Total	Percent Congestion Expected	Congestion Expected	No Congestion Expected	Total	Percent Congestion Expected
<=5	1,061	10,419	11,480	9.2%	1,110	10,347	11,457	9.7%
>5 & <=30	209	1,831	2,040	10.2%	253	1,967	2,220	11.4%
>30	84	679	763	11.0%	81	700	781	10.4%
Total	1,354	12,929	14,283	9.5%	1,444	13,014	14,458	10.0%

Table 12-30 Transmission facility outage requests that by received status, congestion and emergency: January through September of 2014 and 2015

		2014 (Jan - Sep)				2015 (Jan - Sep)			
Submission Status		Congestion Expected	No Congestion Expected	Total	Percent Congestion	Congestion Expected	No Congestion Expected	Total	Percent Congestion
Late	Emergency	67	2,138	2,205	3.0%	94	1,947	2,041	4.6%
	Non Emergency	262	4,622	4,884	5.4%	257	4,828	5,085	5.1%
On Time	Emergency	1	11	12	8.3%	3	9	12	25.0%
	Non Emergency	1,024	6,158	7,182	14.3%	1,090	6,230	7,320	14.9%
Total		1,354	12,929	14,283	9.5%	1,444	13,014	14,458	10.0%

Table 12-31 Transmission facility outage requests that might cause congestion status summary: January through September of 2014 and 2015

		2014 (Jan - Sep)						2015 (Jan - Sep)					
Submission Status		Cancelled	Complete	In Process	Denied	Congestion Expected	Percent Complete	Cancelled	Complete	In Process	Denied	Congestion Expected	Percent Complete
Late	Emergency	3	63	1	0	67	94.0%	10	82	1	1	94	87.2%
	Non Emergency	48	184	1	29	262	70.2%	49	174	6	28	257	67.7%
On Time	Emergency	1	0	0	0	1	0.0%	0	3	0	0	3	100.0%
	Non Emergency	223	736	1	64	1,024	71.9%	295	720	24	51	1,090	66.1%
Total		275	983	3	93	1,354	72.6%	354	979	31	80	1,444	67.8%

Table 12-30 shows the outage requests summary by received status, congestion status and emergency status. In the first nine months of 2015, 71.4 percent of late requests were non-emergency outages while 5.1 percent of late non-emergency outage requests were expected to cause congestion in the first nine months of 2015.

Once PJM processes an outage request, the outage request is labelled as submitted, received, denied, approved, cancelled by company, revised, active or complete according to the processed stage of a request.[58] Table 12-31 shows the detailed process status for outage requests only for the outage requests that are expected to cause congestion. All process status categories except cancelled, complete or denied are in the In Process category in Table 12-31. Table 12-31 shows that 67.7 percent of late, non-emergency, outage requests which were expected to cause congestion were approved and completed and 5.5 (80 out of 1,444) percent of the outage requests which were expected to cause congestion were denied in the first nine months of 2015.

There are clear rules defined for on time or late status for submitted outage requests in both the PJM Tariff and PJM Manuals.[59] However, the outcome of the rules (on time or late) only affects the priority that PJM assigns to process the outage request. Many (67.8 percent) non-emergency, expected to cause congestion, 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 have a

58 See PJM. "Outage Information," <http://www.pjm.com/markets-and-operations/etools/oasis/system-information/outage-info.aspx> (November 1, 2015).

59 OATT Attachment K Appendix § 1.9.2 (Outage Scheduling)

clear definition of the congestion analysis required for transmission outage requests in Manual 3.

Rescheduling Transmission Facility Outage Requests

A TO can reschedule or cancel an outage after initial submission. Table 12-32 is a summary of all the outage requests planned for the first nine months of 2014 and 2015 which were approved and then cancelled or revised by TOs at least once. In the first nine months of 2015, 2.6 percent of transmission outage requests were approved by PJM and then revised by the TOs, and 12.8 percent of the transmission outages were approved by PJM and subsequently cancelled by the TOs.

Table 12-32 Rescheduled transmission outage request summary: January through September of 2014 and 2015

	2014 (Jan - Sep)					2015 (Jan - Sep)				
Days	Outage Requests	Approved and Revised	Percent Approved and Revised	Approved and Cancelled	Percent Approved and Cancelled	Outage Requests	Approved and Revised	Percent Approved and Revised	Approved and Cancelled	Percent Approved and Cancelled
<=5	11,480	363	3.2%	1,629	14.2%	11,457	284	2.5%	1,629	14.2%
>5 & <=30	2,040	85	4.2%	145	7.1%	2,220	70	3.2%	162	7.3%
>30	763	29	3.8%	39	5.1%	781	28	3.6%	55	7.0%
Total	14,283	477	3.3%	1,813	12.7%	14,458	382	2.6%	1,846	12.8%

All late rescheduled outages are reevaluated by PJM. An on time 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.[60] This rule allows a TO to move an outage to an earlier date than originally requested within the same month with very little notice.

An on time transmission outage ticket with duration exceeding five days can retain its on time status if the outage is moved to a future month, and the revision is submitted by the first of the month prior to the month in which new proposed outage will occur.[61] 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 planned to last longer than five days needs to be submitted the first of the month six months prior to the month in which the outage was expected to occur.

The MMU recommends that PJM reevaluate all transmission outage tickets 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 has rules (Table 12-26) to define that a transmission outage request is on time or late based on the planned outage duration. The rule has stricter submission requirement for transmission outage requests planned for longer than 30 days. In order to avoid the stricter submission requirement, some transmission owners broke the duration of outage requests longer than 30 days into shorter segments for the same equipment and submitted one request for each segment. Table 12-33 shows that there were 9,097 transmission equipment planned outages in the first nine months of 2015, of which 714 were planned outages longer than 30 days without breaking into shorter periods, and 118 were planned outages longer than 30 days that were divided into separate shorter periods. There were 8,957 transmission equipment planned outages in the first nine months of 2014, of which 685 were planned outages longer than 30 days without breaking into shorter periods, and 112 were planned outages longer than 30 days that were divided into separate shorter periods.

60 PJM. "Manual 3: Transmission Outages," Revision 46 (December 1, 2014), p. 63.
61 PJM. "Manual 3: Transmission Outages," Revision: 46 (December 1, 2014), p. 64.

Table 12-33 Transmission outage request summary: January through September of 2014 and 2015

		2014		2015	
Duration	Dividing into Shorter Periods	Number of Outages	Percent	Number of Outages	Percent
> 30 Days	No	685	7.6%	714	7.8%
	Yes	112	1.3%	118	1.3%
<= 30 Days		8,160	91.1%	8,265	90.9%
Total		8,957	100.0%	9,097	100.0%

Table 12-34 is a summary of transmission equipment with scheduled outages longer than 30 days when combining all the sequential outage requests related to the equipment. For the equipment with scheduled outages in the first nine months of 2015, 4.2 percent were longer than 30 days when combined all the outages related to the equipment during one month time span, 11.0 percent during two months span, 15.3 percent during three months span, and 69.5 percent during four months or longer. For the equipment with scheduled outages in the first nine months of 2014, 3.6 percent were longer than 30 days when combined all the outages related to the equipment during one month time span, 15.2 percent during two months span, 16.1 percent during three months span, and 65.2 percent during four months or longer.

Table 12-34 Summary of scheduled outages by breaking out into shorter period segments during a period of time span: January through September of 2014 and 2015

	2014		2015	
Span (Months)	Number of Outages	Percent	Number of Outages	Percent
1	4	3.6%	5	4.2%
2	17	15.2%	13	11.0%
3	18	16.1%	18	15.3%
>=4	73	65.2%	82	69.5%
Total	112	100.0%	118	100.0%

Transmission Facility Outage Analysis for the FTR Market

Transmission Facility Outage Analysis for the FTR Market Transmission facility outages affect the price and quantity outcomes of FTR auctions. It is critical that outages are known with enough lead time prior to FTR auctions both so that market participants can understand market conditions and so that PJM can accurately model market conditions. Outage requests must be submitted according to rules based on planned outage duration (Table 12-26). The rules defining when an outage is late are based on the timing of FTR auctions. When an outage request is submitted late, the outage will be marked as late and may be denied if it is expected to cause congestion.

Table 12-41 shows that 43.7 percent of late outage requests with a duration of two weeks or longer but shorter than two months were completed, 1.0 percent were denied by PJM and 18.1 percent of late outage requests with a duration of two weeks or longer but shorter than two months that were approved and active in the 2015 to 2016 planning year. The table also shows that 27.3 percent of late outage requests with duration of two months or longer were completed, none of them were denied, and 43.8 percent were approved and active in the 2015 to 2016 planning year.

There are Long Term, Annual and Monthly Balance of Planning Period auctions in the FTR market. When modeling transmission outages in the annual ARR allocation and FTR auction, PJM does not consider outages with planned duration shorter than two weeks, does consider some outages with planned duration longer than two weeks but shorter than two months, and does consider all outages with planned duration longer than or equal to two months. PJM posts an FTR outage list to the FTR web page usually at least one week before the auction bidding opening day.[62]

Table 12-35 shows that 85.5 (8,979 out of 10,476) percent of the outage requests for outages expected to occur during the planning period 2015 to 2016 had a planned duration of less than two weeks and that 38.8 percent of all outage requests for the planning period were submitted late according to outage submission rules.

62 PJM "Annual ARR Allocation and FTR Auction Transmission Outage Modeling," <http://www.pjm.com/~/media/markets-ops/ftr/annual-ftr-auction/2015-2016/2015-2016-annual-outage-modeling.ashx>

Table 12-35 Transmission facility outage requests by received status: Planning period 2015 to 2016

Planned Duration	On Time	Late	Total	Percent Late
<2 weeks	5,451	3,528	8,979	39.3%
>=2 weeks & <2 months	796	414	1,210	34.2%
>=2 months	157	121	278	43.5%
Total	6,404	4,063	10,467	38.8%

Table 12-36 shows that 89.9 (17,633 out of 19,605) percent of the outage requests for outages expected to occur during the planning period 2014 to 2015 had a planned duration of less than two weeks and that 47.7 percent of all outage requests for the planning period were submitted late according to outage submission rules.

Table 12-36 Transmission facility outage requests by received status: Planning period 2014 to 2015

Planned Duration	On Time	Late	Total	Percent Late
<2 weeks	9,291	8,342	17,633	47.3%
>=2 weeks & <2 months	805	820	1,625	50.5%
>=2 months	155	192	347	55.3%
Total	10,251	9,354	19,605	47.7%

Once received, PJM processes outage requests in the following priority order: emergency transmission outage request, transmission outage requests submitted On Time, and transmission submitted Late. If two outage requests submitted by different transmission owners are expected to occur during the same period, the outage submitted first is processed first by PJM. If a request has an emergency flag, it has the highest priority and will be approved even if submitted past its deadline after PJM determines that the outage does not result in Emergency Procedures.[63] Table 12-37 shows outage requests summary by emergency status. Of all outage requests submitted late in the 2015 to 2016 planning year, 73.7 percent were for non-emergency outages.

Table 12-37 Transmission facility outage requests by received status and emergency: Planning period 2015 to 2016

	On Time			Late		
Planned Duration	Emergency	Non Emergency	Percent Non Emergency	Emergency	Non Emergency	Percent Non Emergency
<2 weeks	11	5,440	99.8%	990	2,538	71.9%
>=2 weeks & <2 months	1	795	99.9%	61	353	85.3%
>=2 months	1	156	99.4%	16	105	86.8%
Total	13	6,391	99.8%	1,067	2,996	73.7%

Table 12-38 shows outage requests summary by emergency status. Of all outage requests submitted late in the 2014 to 2015 planning year, 72.7 percent were for non-emergency outages.

Table 12-38 Transmission facility outage requests by received status and emergency: Planning period 2014 to 2015

	On Time			Late		
Planned Duration	Emergency	Non Emergency	Percent Non Emergency	Emergency	Non Emergency	Percent Non Emergency
<2 weeks	13	9,278	99.9%	2,362	5,980	71.7%
>=2 weeks & <2 months	0	805	100.0%	155	665	81.1%
>=2 months	0	155	100.0%	35	157	81.8%
Total	13	10,238	99.9%	2,552	6,802	72.7%

PJM analyzes 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 12-39 shows a summary of requests by expected congestion and received status. Overall, 5.2 percent of all tickets submitted late in the 2015 to 2016 planning year were requests that might cause congestion.

63 PJM. "Manual 3: Transmission Outages," Revision: 47A (July 1, 2015), p. 67 and p.68.

Table 12-39 Transmission facility outage requests by submission status and congestion: Planning period 2015 to 2016

	On Time			Late		
Planned Duration	Congestion Expected	No Congestion Expected	Percent Congestion Expected	Congestion Expected	No Congestion Expected	Percent Congestion Expected
<2 weeks	756	4,695	13.9%	183	3,345	5.2%
>=2 weeks & <2 months	128	668	16.1%	24	390	5.8%
>=2 months	33	124	21.0%	3	118	2.5%
Total	917	5,487	14.3%	210	3,853	5.2%

Table 12-40 shows a summary of requests by expected congestion and received status. Overall, 5.3 percent of all tickets submitted late in the 2014 to 2015 planning year were requests that might cause congestion.

Table 12-40 Transmission facility outage requests by submission status and congestion: Planning period 2014 to 2015

	On Time			Late		
Planned Duration	Congestion Expected	No Congestion Expected	Percent Congestion Expected	Congestion Expected	No Congestion Expected	Percent Congestion Expected
<2 weeks	1,332	7,959	14.3%	445	7,897	5.3%
>=2 weeks & <2 months	160	645	19.9%	43	777	5.2%
>=2 months	32	123	20.6%	6	186	3.1%
Total	1,524	8,727	14.9%	494	8,860	5.3%

Table 12-41 shows that 43.7 percent of late outage requests with a duration of two weeks or longer but shorter than two months were completed and 18.1 percent were approved and active in the 2015 to 2016 planning year. It also shows that that 27.3 percent of late outage requests with a duration of two months or longer were completed and 43.8 percent were approved and active in the 2015 to 2016 planning period.

Table 12-41 Transmission facility outage requests by received status and processed status: Planning period 2015 to 2016

Planned Duration	Processed Status	On Time	Percent	Late	Percent
<2 weeks	In Progress	2,086	38.3%	320	9.1%
	Denied	46	0.8%	25	0.7%
	Approved	114	2.1%	62	1.8%
	Cancelled by Company	1,133	20.8%	424	12.0%
	Revised	17	0.3%	1	0.0%
	Active	72	1.3%	59	1.7%
	Completed	1,983	36.4%	2,637	74.7%
Total Submission		5,451	100.0%	3,528	100.0%
>=2 weeks & <2 months	In Progress	439	55.2%	109	26.3%
	Denied	0	0.0%	4	1.0%
	Approved	12	1.5%	7	1.7%
	Cancelled by Company	143	18.0%	35	8.5%
	Revised	14	1.8%	3	0.7%
	Active	86	10.8%	75	18.1%
	Completed	102	12.8%	181	43.7%
Total Submission		796	100.0%	414	100.0%
>=2 months	In Progress	60	38.2%	23	19.0%
	Denied	0	0.0%	0	0.0%
	Approved	1	0.6%	1	0.8%
	Cancelled by Company	28	17.8%	11	9.1%
	Revised	2	1.3%	0	0.0%
	Active	59	37.6%	53	43.8%
	Completed	7	4.5%	33	27.3%
Total Submission		157	100.0%	121	100.0%

Table 12-42 shows that 86.3 percent of late outage requests with a duration of two weeks or longer but shorter than two months were completed and that 86.5 percent of late outage requests with a duration of two months or longer were completed in the 2014 to 2015 planning period.

Table 12-42 Transmission facility outage requests by received status and processed status: Planning period 2014 to 2015

Planned Duration	Processed Status	On Time	Percent	Late	Percent
<2 weeks	In Process	22	0.2%	149	1.8%
	Denied	105	1.1%	97	1.2%
	Cancelled by Company	2,759	29.7%	1,200	14.4%
	Completed	6,405	68.9%	6,896	82.7%
Total		9,291	100.0%	8,342	100.0%
>=2 weeks & <2 months	In Process	1	0.1%	8	1.0%
	Denied	0	0.0%	4	0.5%
	Cancelled by Company	194	24.1%	100	12.2%
	Completed	610	75.8%	708	86.3%
Total		805	100.0%	820	100.0%
>=2 months	In Process	0	0.0%	7	3.6%
	Denied	0	0.0%	0	0.0%
	Cancelled by Company	38	24.5%	19	9.9%
	Completed	117	75.5%	166	86.5%
Total		155	100.0%	192	100.0%

Table 12-43 shows that there were 441 outage requests with a duration of two weeks or longer but shorter than two months submitted late, of which 23 were non-emergency and expected to cause congestion in the 2015 to 2016 planning year. Of the 23 such requests, 11 were approved and completed and four were approved and active. For the outages planned for two months or longer, there were 278 total outages, of which 121 requests were late. Of the late requests, three outages that were non-emergency and expected to cause congestion were all approved and completed and one were approved and active.

Table 12-43 Transmission facility outage requests by received status, processed status, emergency and congestion: Planning period 2015 to 2016

		On Time					Late				
		Emergency		Non Emergency			Emergency		Non Emergency		
		Emergency Congestion Expected		Congestion Expected			Congestion Expected		Congestion Expected		
Planned Duration	Processed Status	Yes	No	Yes	No	Total	Yes	No	Yes	No	Total
<2 weeks	In Progress	0	2	255	1,829	2,086	0	39	20	261	320
	Denied	0	0	25	21	46	0	7	9	9	25
	Approved	0	0	10	104	114	0	1	3	58	62
	Cancelled by Company	0	1	151	981	1,133	4	64	25	331	424
	Revised	0	0	4	13	17	0	0	0	1	1
	Active	0	0	12	60	72	0	9	1	49	59
	Completed	3	5	296	1,679	1,983	44	822	77	1,694	2,637
Total Submission		3	8	753	4,687	5,451	48	942	135	2,403	3,528
>=2 weeks & <2 months	In Progress	0	0	63	376	439	0	6	7	96	109
	Denied	0	0	0	0	0	0	0	0	4	4
	Approved	0	0	1	11	12	0	0	1	6	7
	Cancelled by Company	0	1	14	128	143	0	0	0	35	35
	Revised	0	0	4	10	14	0	0	0	3	3
	Active	0	0	21	65	86	1	7	4	63	75
	Completed	0	0	25	77	102	0	47	11	123	181
Total Submission		0	1	128	667	796	1	60	23	330	414
>=2 months	In Progress	0	0	10	50	60	0	1	1	21	23
	Denied	0	0	0	0	0	0	0	0	0	0
	Approved	0	0	0	1	1	0	0	0	1	1
	Cancelled by Company	0	0	1	27	28	0	1	0	10	11
	Revised	0	0	0	2	2	0	0	0	0	0
	Active	0	1	21	37	59	0	9	1	43	53
	Completed	0	0	1	6	7	0	5	1	27	33
Total Submission		0	1	33	123	157	0	16	3	102	121

Table 12-44 shows that there were 820 outage requests with a duration of two weeks or longer but shorter than two months submitted late, of which 40 were non-emergency and expected to cause congestion in the 2014 to 2015 planning year. Of the 40 such requests, 33 were approved and completed. For the outages planned for two months or longer, there are 347 total outages, of which 192 requests were late. Of the late request, six outages that were non-emergency and expected to cause congestion were all approved and completed.

Table 12-44 Transmission facility outage requests by received status, processed status, emergency and congestion: Planning period 2014 to 2015

		On Time					Late				
		Emergency		Non Emergency			Emergency		Non Emergency		
		Emergency Congestion Expected		Congestion Expected			Congestion Expected		Congestion Expected		
Planned Duration	Processed Status	Yes	No	Yes	No	Total	Yes	No	Yes	No	Total
<2 weeks	In Progress	0	0	2	20	22	0	70	3	76	149
	Denied	0	0	70	35	105	1	12	39	45	97
	Cancelled by Company	1	1	362	2,395	2,759	9	135	74	982	1,200
	Completed	0	11	897	5,497	6,405	96	2,039	223	4,538	6,896
Total Submission		1	12	1,331	7,947	9,291	106	2,256	339	5,641	8,342
>=2 weeks & <2 months	In Progress	0	0	1	0	1	0	3	0	5	8
	Denied	0	0	0	0	0	0	1	2	1	4
	Cancelled by Company	0	0	30	164	194	0	5	5	90	100
	Completed	0	0	129	481	610	3	143	33	529	708
Total Submission		0	0	160	645	805	3	152	40	625	820
>=2 months	In Progress	0	0	0	0	0	0	1	0	6	7
	Denied	0	0	0	0	0	0	0	0	0	0
	Cancelled by Company	0	0	3	35	38	0	1	0	18	19
	Completed	0	0	29	88	117	0	33	6	127	166
Total Submission		0	0	32	123	155	0	35	6	151	192

Table 12-45 Transmission facility outage requests by received status and bidding opening date: Planning period 2015 to 2016

	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
<2 weeks	1,313	4,138	75.9%	65	3,463	98.2%
>=2 weeks & <2 months	558	238	29.9%	62	352	85.0%
>=2 months	143	14	8.9%	25	96	79.3%
Total	2,014	4,390	68.6%	152	3,911	96.3%

If an outage request were submitted after the Annual FTR Auction bidding opening date, the outage would not be considered in the FTR model. If an outage were submitted on time according to the transmission outage rules, it may not be modeled in the FTR model if it is submitted after the Annual FTR Auction bidding opening date. Table 12-45 shows that 68.6 percent of outage requests labelled on time according to rules were submitted after the annual FTR bidding opening date in the 2015 to 2016 planning year.

Table 12-46 shows that 84.0 percent of outage requests labelled on time according to rules were submitted after the annual FTR bidding opening date.

Table 12-46 Transmission facility outage requests by received status and bidding opening date: Planning period 2014 to 2015

	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
<2 weeks	1,040	8,251	88.8%	78	8,264	99.1%
>=2 weeks & <2 months	475	330	41.0%	77	743	90.6%
>=2 months	127	28	18.1%	18	174	90.6%
Total	1,642	8,609	84.0%	173	9,181	98.2%

Table 12-47 shows that 71.2 percent of late outage requests which were submitted after the Annual FTR Auction bidding opening date were approved and complete in the 2015 to 2016 planning.

Table 12-47 Late transmission facility outage requests that are submitted after annual bidding opening date: Planning period 2015 to 2016

Planned Duration	Completed Outages	Total	Percent
<2 weeks	2,598	3,463	75.0%
>=2 weeks & <2 months	156	352	44.3%
>=2 months	31	96	32.3%
Total	2,785	3,911	71.2%

Table 12-48 shows that 83.2 percent of late outage requests which were submitted after the Annual FTR Auction bidding opening date were approved and complete in the 2014 to 2015 planning year.

Table 12-48 Late transmission facility outage requests that are submitted after annual bidding opening date: Planning period 2014 to 2015

Planned Duration	Completed Outages	Total	Percent
<2 weeks	6,838	8,264	82.7%
>=2 weeks & <2 months	648	743	87.2%
>=2 months	150	174	86.2%
Total	7,636	9,181	83.2%

Thus, although the definition of late outages was developed in order to prevent outages for the planning period being submitted after the Annual FTR Auction bidding opening date, the rules have not worked to prevent this since the rule has no direct connection to the annual FTR auction opening date. The MMU recommends that PJM redesign the rule so the late outage requests submitted after the FTR Auction bidding opening date will not be approved by PJM.

Transmission Facility Outage Analysis in the Day-Ahead 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 both so that market participants can understand market conditions and so that PJM can accurately model market conditions.

There may be more than one instance for each outage request due to the change of the processed status. PJM maintains the history of outage requests including all the processed status changes and all the starting or ending date changes. For example, if an outage request were submitted, received, approved and completed, the four occurrences, termed instances, of the outage request will be stored in the database. In the day-ahead market transmission outage analysis, all instances of the outages planned in the first nine months of 2014 and 2015 are included. Table 12-49 shows that 13.5 percent of non-emergency outage request instances were submitted late for the day-ahead market and were expected to cause congestion in the first nine months of 2015.

Table 12-49 Transmission facility outage request instance summary by congestion and emergency: January through September of 2015

For Day-ahead Market	Submission Status	Congestion Expected	No Congestion Expected	Total	Percent Congestion
Late	Emergency	250	2,975	3,225	7.8%
	Non Emergency	1,820	11,685	13,505	13.5%
On Time	Emergency	611	9,201	9,812	6.2%
	Non Emergency	11,246	65,419	76,665	14.7%
	Total	13,927	89,280	103,207	13.5%

Table 12-50 shows that 14.1 percent of non-emergency outage request instances were submitted late for the day-ahead market and were expected to cause congestion in the first nine months of 2014.

Table 12-50 Transmission facility outage request instance summary by congestion and emergency: January through September of 2014

For Day-ahead Market	Submission Status	Congestion Expected	No Congestion Expected	Total	Percent Congestion
Late	Emergency	183	3,398	3,581	5.1%
	Non Emergency	1,934	11,789	13,723	14.1%
On Time	Emergency	464	11,104	11,568	4.0%
	Non Emergency	10,103	63,326	73,429	13.8%
	Total	12,684	89,617	102,301	12.4%

Table 12-51 Transmission facility outage request instance status summary by congestion and emergency: January through September of 2015

	Late For Day-ahead Market					On Time For Day-ahead Market				
	Emergency		Non Emergency			Emergency		Non Emergency		
	Congestion Expected		Congestion Expected			Congestion Expected		Congestion Expected		
Processed Status	Yes	No	Yes	No	Total	Yes	No	Yes	No	Total
Submitted	18	741	42	517	1,318	104	1,263	1,665	11,788	14,820
Cancelled by Company	9	34	63	564	670	7	122	436	3,253	3,818
Revised	7	91	36	233	367	78	3,152	2,094	10,690	16,014
Total	34	866	141	1,314	2,355	189	4,537	4,195	25,731	34,652
Other	216	2,109	1,679	10,371	14,375	422	4,664	7,051	39,688	51,825
Total	250	2,975	1,820	11,685	16,730	611	9,201	11,246	65,419	86,477

Table 12-52 Transmission facility outage request instance status summary by congestion and emergency: January through September of 2014

	Late For Day-ahead Market					On Time For Day-ahead Market				
	Emergency		Non Emergency			Emergency		Non Emergency		
	Congestion Expected		Congestion Expected			Congestion Expected		Congestion Expected		
Processed Status	Yes	No	Yes	No	Total	Yes	No	Yes	No	Total
Submitted	13	867	49	511	1,440	75	1,312	1,535	11,007	13,929
Cancelled by Company	2	35	61	514	612	13	118	329	2,721	3,181
Revised	7	148	38	245	438	83	4,427	1,739	10,214	16,463
Total	22	1,050	148	1,270	2,490	171	5,857	3,603	23,942	33,573
Other	161	2,348	1,786	10,519	14,814	293	5,247	6,500	39,384	51,424
Total	183	3,398	1,934	11,789	17,304	464	11,104	10,103	63,326	84,997

Table 12-51 shows that there were 16,730 late instances related to outage requests which were expected to occur in the first nine months of 2015, of which 2,355 (18.2 percent) had the status submitted, cancelled by company or revised and 141 (0.8 percent) non-emergency instances had the status submitted, cancelled by company or revised and were expected to cause congestion.

Table 12-52 shows that there were 17,304 late instances related to outage requests which were expected to occur in the first nine months of 2014, of which 2,490 (14.4 percent) had the status submitted, cancelled by company or revised and 148 (0.9 percent) non-emergency instances had the status submitted, cancelled by company or revised and were expected to cause congestion.