Generation and Transmission Planning

Overview

Planned Generation and Retirements

- **Planned Generation.** As of December 31, 2013, 67,299 MW of capacity were in generation request queues for construction through 2024, compared to an average installed capacity of 195,775 MW at the end of 2013. Of the capacity in queues, 6,557 MW, or 9.7 percent, are uprates and the rest are new generators. Wind projects account for 18,063 MW of nameplate capacity or 26.8 percent of the capacity in the queues. Combined-cycle projects account for 39,420 MW of capacity or 58.5 percent of the capacity in the queues.
- **Generation Retirements.** As shown in Table 12-7, 24,932 MW is or is planned to be retired between 2011 and 2019, with all but 2,016.5 MW retired by June 1, 2015. The AEP Zone accounts for 4,124 MW, or 19.7 percent, of all MW planned for retirement from 2014 through 2019. Since January 1, 2013, 1,437 MW that were scheduled to be retired have withdrawn their retirement notices, and are planning to continue operating, including the Avon Lake and New Castle generating units in the ATSI Zone.
- **Generation Mix.** A potentially significant change in the distribution of unit types within the PJM footprint is likely as a combined result of the location of generation resources in the queue and the location of units likely to retire. In both the Eastern MAAC (EMAAC) and the Southwestern MAAC (SWMAAC) locational deliverability areas (LDAs), the capacity mix is likely to shift to more natural gas-fired combined cycle (CC) and combustion turbine (CT) capacity.[1] Elsewhere in the PJM footprint, continued reliance on steam (mainly coal) seems likely, despite retirements of coal units.

Generation and Transmission Interconnection Planning Process

- Any entity that requests interconnection of a new generating facility, including increases to the capacity of an existing generating unit or that requests interconnection of a merchant transmission facility must follow the process defined in the PJM tariff to obtain interconnection service.[2] The process is complex and time consuming as a result of the nature 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. These projects may create barriers to entry for projects that would otherwise be completed by taking up queue positions, increasing interconnection costs and creating uncertainty.
- Many feasibility, impact and facilities studies are delayed for reasons including disputes with developers, circuit and network issues, retooling as a result of projects being withdrawn and an accumulated backlog in completing studies.
- Changes to the planning process went into effect on May 12, 2012 including a return to six-month queue cycles and the creation of an alternate queue for small projects. Concurrent with these changes was a drop in new projects, starting in 2012 and a corresponding drop in withdrawn projects starting in 2013.

Backbone Facilities

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

1 EMAAC consists of the AECO, DPL, JCPL, PECO and PSEG control zones. SWMAAC consists of the BGE and Pepco control zones. See the *2013 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography" for a map of PJM LDAs.

2 OATT Parts IV & VI.

Regional Transmission Expansion Plan (RTEP)

- The PJM Board of Managers authorized $1.2 billion on October 3, 2013, and $5.9 billion on December 11, 2013, in transmission upgrades and improvements that were identified as part of PJM's regional planning process.

Economic Planning Process

A goal of transmission planning should be the incorporation of transmission investment decisions into market driven processes as much as possible. Transmission investments have not been fully incorporated into competitive markets. The PJM economic planning process could enhance competition in PJM in at least three ways.

- **Competition to Build.** On its own initiative and in compliance with Order No. 1000, PJM introduced limited opportunities for non-incumbent transmission owners to compete with incumbent transmission owners to identify and sponsor the development of projects in the PJM region for economic reasons.[3] The rules accord no right of first refusal to incumbents.[4]
- **Competition to Finance.** Competition to provide financing could reduce the cost of capital for transmission projects and significantly reduce total costs to customers. The MMU recommended this approach in PJM's proceeding on compliance with Order No. 1000 and continues to recommend that PJM implement this approach.[5]
- **Competition to Meet Load.** The construction of new transmission facilities can have significant impacts on energy and capacity markets, but there is no market mechanism in place that would require direct competition between transmission and generation to meet loads in an area. PJM has taken a first step towards integrating transmission investments into the market through the use of economic evaluation metrics and through the ability to offer transmission projects in RPM auctions.[6, 7]

Recommendations

The MMU recommends additional improvements to the planning process.

- There is no mechanism to permit a direct comparison, or competition, between transmission and generation alternatives. There is no mechanism to evaluate whether the generation or transmission alternative is less costly or who bears the risks associated with each alternative. The MMU recommends the creation of such a mechanism.
- The MMU recommends that rules be implemented to permit competition to provide financing of transmission projects. This competition could reduce the cost of capital for transmission projects and significantly reduce total costs to customers.
- 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.[8]
- The MMU recommends outsourcing interconnection studies to an independent party to avoid potential conflicts of interest. Currently, these studies are performed by incumbent transmission owners under PJM's direction. This could result in a conflict of interest when transmission owners have generation interests.
- 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.

3 *See* FERC Docket No. ER13-198; 145 FERC ¶ 61,214.
4 *See* 145 FERC ¶ 61,214 at PP 221–234.
5 Comments of the Independent Market Monitor for PJM, Docket No. ER13-198 (December 10, 2012) at 4–7; 145 FERC ¶ 61,214 at P 268, 281.
6 *See* 126 FERC ¶ 61,152 (2009) (final approval for an approach with predefined formulas for determining whether a transmission investment passes the cost-benefit test including explicit accounting for changes in production costs, the costs of complying with environmental regulations, generation availability trends and demand response trends), order on reh'g, 123 FERC ¶ 61,051 (2008).
7 *See, e.g.,* OATT Attachment DD § 5.6.4 (Qualifying Transmission Upgrades).
8 *See* "Comments of the Independent Market Monitor for PJM," <http://www.monitoringanalytics.com/reports/Reports/2012/IMM_Comments_ER12-1177-000_20120312.pdf> (Accessed December 4, 2013)

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 energy and capacity markets. But when generating units retire, there is no market mechanism in place that would require direct competition between transmission and generation to meet loads in that area. In addition, despite Order No. 1000, there is not yet a robust mechanism to permit competition to build transmission projects or to obtain least cost financing. 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 effectively forestalls the ability of generation to compete. 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 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 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.

Planned Generation and Retirements

Planned Generation Additions

Net revenues provide incentives to build new generation to serve PJM markets. While these incentives operate with a significant lag time and are based on expectations of future net revenue, the amount of planned new generation in PJM reflects investors' perception of the incentives provided by the combination of revenues from the PJM Energy, Capacity and Ancillary Service Markets. On December 31, 2013, 67,299 MW of capacity were in generation request queues for construction through 2024, compared to an average installed capacity of 195,775 MW in 2013. Although it is clear that not all generation in the queues will be built, PJM has added capacity annually since 2000 (Table 12-1).[9] Overall, 1,127 MW of nameplate capacity were added in PJM in 2013.

Table 12-1 Year-to-year capacity additions from PJM generation queue: Calendar years 2000 through 2013[10]

	MW
2000	505
2001	872
2002	3,841
2003	3,524
2004	1,935
2005	819
2006	471
2007	1,265
2008	2,777
2009	2,516
2010	2,097
2011	5,008
2012	2,669
2013	1,127

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 entered projects for a given queue when that queue closes. The duration of the queue period has varied over time in an attempt to improve the efficiency of the queue process. Queues A and B were each open for a year. Queues C-T were open for six months. Starting in February 2008, for Queues U-Y1, the window was reduced to three months. In May 2012, the queue window was set back to six months, starting with Queue Y2. Queue Z2 is currently open.

All projects that have been entered in a queue will have an assigned status. 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

9 The capacity additions are new MW by year, including full nameplate capacity of solar and wind facilities and are not net of retirements or adjusted for deratings.

10 The capacity described in Table 12-1 refers to all installed capacity in PJM, regardless of whether the capacity entered the RPM auction. In addition, wind capacity has been adjusted to reflect derating.

and listed separately. A project cannot be suspended until it has reached the status of under construction. A project suspended for more than three years is subject to termination of the Interconnection Service Agreement and corresponding cancellation costs.

Table 12-2 shows MW in queues by expected completion date and changes in the queues from January 1, 2013 to December 31, 2013, for ongoing projects, i.e. projects with the status active, under construction or suspended. Projects that are already in service are not included here. The total MW in queues for these projects decreased by 12,178 MW or 15.3 percent from 79,476 MW at the beginning of 2013 to 67,299 MW at the end of 2013. The change is a result of 11,669 MW in new projects entering the queue, 21,432 MW in existing projects being withdrawn, and 1,737 MW going into service. The remaining difference is the result of projects adjusting their expected.

Table 12-2 Queue comparison by expected completion year (MW): January 1, 2013 vs. December 31, 2013[11]

	As of 1/1/2013	As of 12/31/2013	Year-to-Year Change (MW)	Year-to-Year Change
≤ 2013	22,929	11,672	(11,257)	(49.1%)
2014	8,509	7,360	(1,149)	(13.5%)
2015	22,742	12,674	(10,069)	(44.3%)
2016	11,977	13,953	1,976	16.5%
2017	10,018	16,003	5,985	59.7%
2018	3,301	3,697	396	12.0%
2019	0	0	0	NA
2020	0	346	346	NA
2024	0	1,594	1,594	NA
Total	79,476	67,299	(12,178)	(15.3%)

Table 12-3 Change in project status (MW): January 1, 2013 vs. December 31, 2013

		Status at 12/31/2013				
Status at 1/1/2013	Total at 1/1/2013	Active	Suspended	Under Construction	In Service	Withdrawn
(Entered in 2013)		11,643	0	26	10	3,204
Active	62,511	37,310	1,367	4,491	304	19,039
Suspended	3,283	0	2,274	288	150	571
Under Construction	13,005	0	648	9,252	1,283	1,823
In Service	33,789	0	0	0	33,786	3
Withdrawn	234,621	0	0	0	0	234,621
Total at 12/31/2013		48,953	4,288	14,057	35,532	259,261

Table 12-3 shows the yearly project status changes in more detail and how scheduled queue capacity has changed from the beginning of 2013 to the end of 2013. For example, 14,883 MW entered the queue in 2013, 3,204 MW of which were withdrawn before the end of the year. Of the total 62,511 MW marked as active at the beginning of the year, 19,039 MW were withdrawn, 1,367 MW were suspended, and 4,491 MW started construction. The “In Service” column shows that 1,747 MW went into service in 2013, in addition to the 33,786 MW of capacity that already had the status “in service” at the beginning of the year.

Table 12-4 shows the amount of capacity active, in-service, under construction, suspended, or withdrawn for each queue since the beginning of the regional transmission expansion plan (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 December 31, 2013, there are 67,299 MW of capacity in queues that are not yet in service of which 6.4 percent is suspended and 20.9 percent is under construction. The remaining 72.7 percent, or 48,953 MW, have not yet begun construction.

Table 12-5 shows that for successful projects, there is an average time of 2,895 days, or 7.9 years, between entering a queue and going into service. For withdrawn projects, there is an average time of 609 days between entering a queue and withdrawing. It takes an average of 3.1 years to begin construction, with the worst case taking 12.7 years.

11 Wind capacity in Table 12-2 and Table 12-3 has not been adjusted to reflect derating.

Table 12-4 Capacity in PJM queues (MW): At December 31, 2013[12]

Queue	Active	In-Service	Under Construction	Suspended	Withdrawn	Total
A Expired 31-Jan-98	0	8,103	0	0	17,347	25,450
B Expired 31-Jan-99	0	4,646	0	0	14,957	19,602
C Expired 31-Jul-99	0	531	0	0	3,471	4,002
D Expired 31-Jan-00	0	851	0	0	7,182	8,033
E Expired 31-Jul-00	0	795	0	0	8,022	8,817
F Expired 31-Jan-01	0	52	0	0	3,093	3,145
G Expired 31-Jul-01	0	1,116	0	0	17,934	19,050
H Expired 31-Jan-02	0	703	0	0	8,422	9,124
I Expired 31-Jul-02	0	103	0	0	3,728	3,831
J Expired 31-Jan-03	0	40	0	0	846	886
K Expired 31-Jul-03	0	218	0	0	2,425	2,643
L Expired 31-Jan-04	0	257	0	0	4,034	4,290
M Expired 31-Jul-04	0	505	150	0	3,706	4,360
N Expired 31-Jan-05	0	2,399	88	0	8,040	10,527
O Expired 31-Jul-05	10	1,688	225	217	5,451	7,592
P Expired 31-Jan-06	43	3,065	253	210	5,068	8,638
Q Expired 31-Jul-06	105	2,498	2,244	0	9,687	14,534
R Expired 31-Jan-07	1,226	1,386	728	440	18,974	22,755
S Expired 31-Jul-07	875	3,281	577	420	11,989	17,142
T Expired 31-Jan-08	3,671	1,319	631	868	21,068	27,556
U Expired 31-Jan-09	1,951	824	400	690	29,492	33,357
V Expired 31-Jan-10	3,148	266	2,696	172	10,720	17,001
W Expired 31-Jan-11	4,860	498	2,091	780	15,992	24,222
X Expired 31-Jan-12	11,638	282	3,656	29	14,762	30,366
Y Expired 30-Apr-13	12,584	109	318	462	12,636	26,109
Z through 31-Dec-13	8,842	0	0	0	217	9,060
Total	48,953	35,532	14,057	4,288	259,261	362,092

Table 12-5 Average project queue times (Days) at December 31, 2013

Status	Average (Days)	Standard Deviation	Minimum	Maximum
Active	1,168	696	67	4,636
In-Service	2,895	1,377	262	6,124
Suspended	2,074	850	941	3,846
Under Construction	1,611	735	320	6,380
Withdrawn	609	623	0	4,249

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

Distribution of Units in the Queues

Table 12-6 shows the projects under construction, suspended, or active as of December 31, 2013, by unit type, control zone and LDA.[13] The geographic distribution of generation in the queues shows that new capacity is being added disproportionately in the west, and includes a substantial amount of wind capacity.[14] As of December 31, 2013, 67,299 MW of capacity were in generation request queues for construction through 2024, compared to 79,476 MW at January 1, 2013. Of the 24,640 MW withdrawn from the queues in 2013, 14,262 MW were natural gas projects, 5,871 MW were wind projects, and 2,966 MW were coal projects.

A potentially significant change in the distribution of unit types within the PJM footprint is likely as a combined result of the location of generation resources in the queue (Table 12-6) and the location of units likely to retire. In both the EMAAC and SWMAAC LDAs, the capacity mix is likely to shift to more natural gas-fired combined cycle (CC) and combustion turbine (CT) capacity. The western part of the PJM footprint is also likely to see a shift to more natural gas-fired capacity due to changes in environmental regulations and natural gas costs, but likely will maintain a larger amount of coal steam capacity than eastern zones. The replacement of older 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.

Table 12-6 Queue capacity by control zone and LDA (MW) at December 31, 2013[15]

LDA	Zone	CC	CT	Diesel	Hydro	Nuclear	Solar	Steam	Storage	Wind	Total
EMAAC	AECO	1,684	71	8	0	0	377	0	0	1,069	3,208
	DPL	1,223	23	0	0	0	348	20	20	279	1,913
	JCPL	1,456	0	0	20	0	795	0	0	0	2,271
	PECO	861	17	6	0	330	0	0	2	0	1,215
	PSEG	3,374	326	9	0	0	163	0	1	0	3,873
	EMAAC Total	8,598	436	22	20	330	1,683	20	23	1,348	12,480
SWMAAC	BGE	678	256	29	0	0	22	132	0	0	1,117
	Pepco	3,078	0	0	0	0	0	0	0	0	3,078
	SWMAAC Total	3,756	256	29	0	0	22	132	0	0	4,195
WMAAC	Met-Ed	800	6	0	0	50	3	0	0	0	859
	PENELEC	919	121	39	40	0	32	0	10	755	1,916
	PPL	5,052	0	7	3	0	29	0	40	664	5,795
	WMAAC Total	6,771	127	46	43	50	64	0	50	1,419	8,569
Non-MAAC	AE	452	10	0	0	0	0	0	0	0	462
	AEP	6,399	40	20	7	102	96	302	98	8,241	15,305
	APS	2,009	1,418	63	59	0	2	49	0	428	4,029
	ATSI	2,425	1,484	0	0	0	15	135	0	867	4,926
	ComEd	1,170	216	32	23	120	19	0	81	4,047	5,707
	DAY	0	0	2	112	0	23	12	12	300	461
	DEOK	540	0	0	0	0	0	50	16	0	606
	DLCO	245	0	0	0	0	0	0	0	0	245
	Dominion	6,920	62	11	0	1,594	45	103	32	1,262	10,029
	EKPC	0	0	0	0	0	0	0	0	150	150
	Essential Power	135	0	0	0	0	0	0	0	0	135
	Non-MAAC Total	20,296	3,230	128	201	1,816	200	650	239	15,295	42,055
Total		39,420	4,049	225	264	2,196	1,969	802	311	18,063	67,299

13 Unit types designated as reciprocating engines are classified here as diesel.

14 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 18,063 MW of wind resources and 1,969 MW of solar resources, the 67,299 MW currently active in the queue would be reduced to 54,387 MW.

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

Planned Retirements

As shown in Table 12-7, 24,932.5 MW is planned to be retired between 2011 and 2019, with all but 2,016.5 MW retired by June, 2015. The AEP Zone accounts for 5,224 MW, or 21.0 percent, of all MW planned for deactivation from 2014 through 2019. Since January 1, 2013, 1,437 MW scheduled to be deactivated have withdrawn their deactivation notices and are planning to continue operating, including the Avon Lake and New Castle generating units in the ATSI Zone. A map of retirements between 2011 and 2019 is shown in Figure 12-1 and a detailed list of pending deactivations is shown in Table 12-8.

Table 12-7 Summary of PJM unit retirements (MW): 2011 through 2019

	MW
Retirements 2011	1,196.5
Retirements 2012	6,961.9
Retirements 2013	2,862.6
Retirements 2014	50.0
Planned Retirements 2014	1,870.0
Planned Retirements 2015	9,975.0
Planned Retirements Post-2015	2,016.5
Total	24,932.5

Figure 12-1 Map of PJM unit retirements: 2011 through 2019

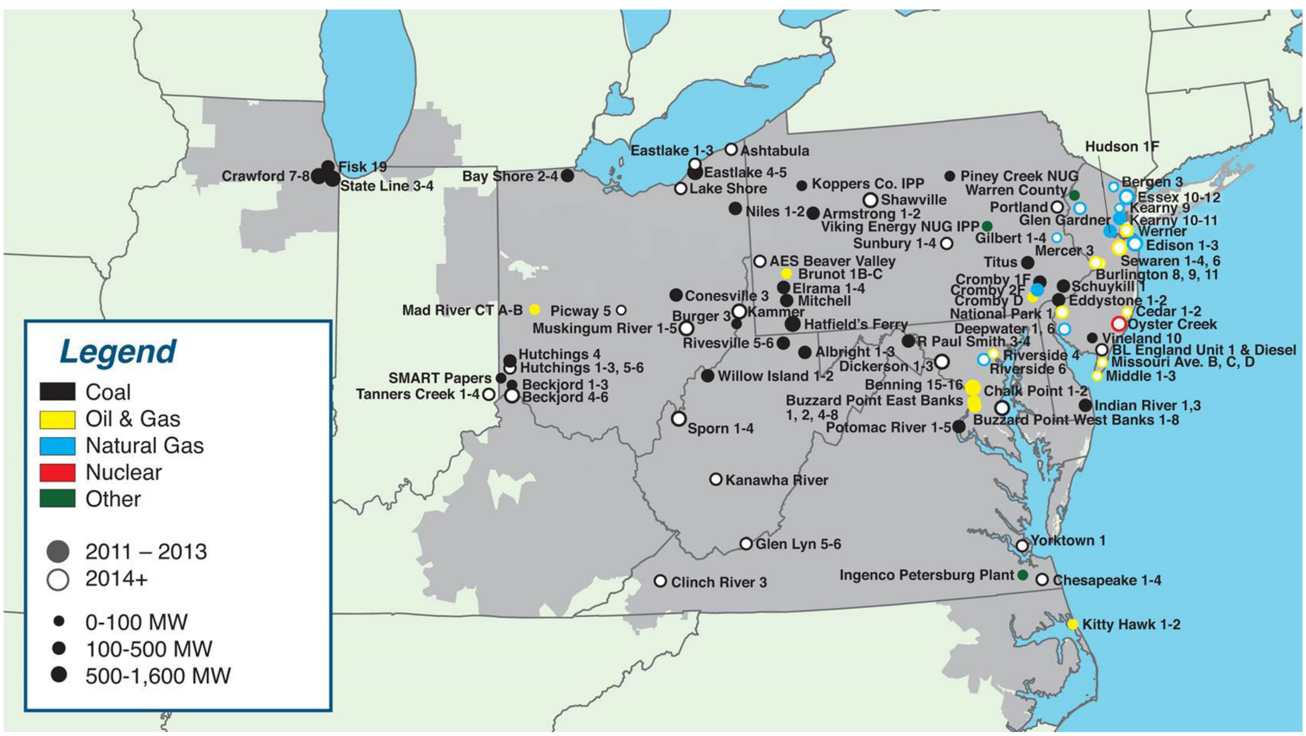


Table 12-8 Planned deactivations of PJM units, as of December 31, 2013

Unit	Zone	MW	Fuel	Unit Type	Projected Deactivation Date
BL England 1	AECO	113.0	Coal	Steam	01-May-14
Deepwater 1, 6	AECO	158.0	Natural gas	Steam	01-Jun-14
Burlington 9	PSEG	184.0	Kerosene	Combustion Turbine	01-Jun-14
Portland	Met-Ed	401.0	Coal	Steam	01-Jun-14
Riverside 6	BGE	115.0	Natural gas	Combustion Turbine	31-Dec-14
Chesapeake 1-4	Dominion	576.0	Coal	Steam	31-Dec-14
Yorktown 1-2	Dominion	323.0	Coal	Steam	01-Apr-15
Walter C Beckjord 4-6	DEOK	802.0	Coal	Steam	16-Apr-15
Shawville 1-7	PENELEC	603.0	Coal	Steam	01-May-15
Gilbert 1-4	JCPL	98.0	Natural gas	Combustion Turbine	01-May-15
Glen Gardner 1-8	JCPL	160.0	Natural gas	Combustion Turbine	01-May-15
Kearny 9	PSEG	21.0	Natural gas	Combustion Turbine	01-May-15
Werner 1-4	JCPL	212.0	Light oil	Combustion Turbine	31-May-15
Cedar 1-2	AECO	65.6	Kerosene	Combustion Turbine	31-May-15
Essex 12	PSEG	184.0	Natural gas	Combustion Turbine	31-May-15
Middle 1-3	AECO	74.7	Kerosene	Combustion Turbine	31-May-15
Missouri Ave B, C, D	AECO	57.9	Kerosene	Combustion Turbine	01-Jun-15
Ashtabula	ATSI	210.0	Coal	Steam	01-Jun-15
Bergen 3	PSEG	21.0	Natural gas	Combustion Turbine	01-Jun-15
Burlington 8, 11	PSEG	205.0	Kerosene	Combustion Turbine	01-Jun-15
Clinch River 3	AEP	230.0	Coal	Steam	01-Jun-15
Eastlake 1-3	ATSI	327.0	Coal	Steam	01-Jun-15
Edison 1-3	PSEG	504.0	Natural gas	Combustion Turbine	01-Jun-15
Essex 10-11	PSEG	352.0	Natural gas	Combustion Turbine	01-Jun-15
Glen Lyn 5-6	AEP	325.0	Coal	Steam	01-Jun-15
Hutchings 1-3, 5-6	DAY	271.8	Coal	Steam	01-Jun-15
Kammer 1-3	AEP	600.0	Coal	Steam	01-Jun-15
Kanawha River 1-2	AEP	400.0	Coal	Steam	01-Jun-15
Lake Shore	ATSI	190.0	Coal	Steam	01-Jun-15
Mercer 3	PSEG	115.0	Kerosene	Combustion Turbine	01-Jun-15
Muskingum River 1-5	AEP	1,355.0	Coal	Steam	01-Jun-15
National Park 1	PSEG	21.0	Kerosene	Combustion Turbine	01-Jun-15
Picway 5	AEP	95.0	Coal	Steam	01-Jun-15
Sewaren 1-4,6	PSEG	558.0	Kerosene	Combustion Turbine	01-Jun-15
Sporn 1-4	AEP	580.0	Coal	Steam	01-Jun-15
Sunbury 1-4	PPL	347.0	Coal	Steam	01-Jun-15
Tanners Creek 1-4	AEP	982.0	Coal	Steam	01-Jun-15
BL England Diesels	AECO	8.0	Diesel	Diesel	01-Oct-15
Riverside 6	BGE	74.0	Natural gas	Combustion Turbine	01-Jun-16
Chalk Point 1-2	Pepco	667.0	Coal	Steam	31-May-17
Dickerson 1-3	Pepco	537.0	Coal	Steam	31-May-17
AES Beaver Valley	DLCO	124.0	Coal	Steam	01-Jun-17
Oyster Creek	JCPL	614.5	Nuclear	Steam	31-Dec-19
Total		13,861.5			

Table 12-9 shows the capacity, average size, and average age of units retiring in PJM, from 2011 through 2019. The majority, 76.7 percent, of all MW retiring during this period are coal steam units. These units have an average age of 56.9 years, and an average size of 168.7 MW. This indicates that on average, retirements have consisted of smaller sub-critical coal steam units, and those without adequate environmental controls to remain viable beyond 2015.

Table 12-9 Retirements by fuel type, 2011 through 2019

	Number of Units	Avg. Size (MW)	Avg. Age at Retirement (Years)	Total MW	Percent
Coal	113	168.7	56.9	19,062.6	76.7%
Diesel	5	13.4	42.8	66.9	0.3%
Heavy Oil	2	120.0	60.0	240.0	1.0%
Kerosene	20	41.4	45.5	828.2	3.3%
LFG	1	10.8	7.0	10.8	0.0%
Light Oil	15	76.6	43.8	1,148.7	4.6%
Natural Gas	49	57.9	46.8	2,838.5	11.4%
Nuclear	1	614.5	50.0	614.5	2.5%
Waste Coal	1	31.0	20.0	31.0	0.1%
Wood Waste	2	12.0	23.5	24.0	0.1%
Total	209	119.0	51.4	24,865.2	100.0%

Actual Generation Deactivations in 2013

Table 12-10 shows unit deactivations for 2013.[16] A total of 2,862.6 MW was retired in 2013, plus an additional 50 MW in early January, 2014.

Table 12-10 Unit deactivations between January 1, 2013 and January 15, 2014

Company	Unit Name	ICAP	Primary Fuel	Zone Name	Age (Years)	Retirement Date
Exelon Corporation	Schuylkill 1	166.0	Heavy Oil	PECO	54	01-Jan-13
Exelon Corporation	Schuylkill Diesel	3.0	Diesel	PECO	45	01-Jan-13
Marina Energy	Warren County Landfill	10.8	Landfill Gas	JCPL	07	09-Jan-13
First Energy	Piney Creek NUG	31.0	Waste Coal	PENELEC	20	12-Apr-13
Ingenco Wholesale Power, LLC	Ingenco Petersburg	2.9	Landfill Gas	Dominion	22	31-May-13
The AES Corporation	Hutchings 4	61.9	Coal	DAY	62	01-Jun-13
NRG Energy	Titus 1	81.0	Coal	Met-Ed	60	01-Sep-13
NRG Energy	Titus 2	81.0	Coal	Met-Ed	24	01-Sep-13
NRG Energy	Titus 3	81.0	Coal	Met-Ed	60	01-Sep-13
NextEra Energy	Koppers Co. IPP	08.0	Wood waste	PPL	59	30-Sep-13
Duke Energy	Walter C Beckjord 2	94.0	Coal	DEOK	44	01-Oct-13
Duke Energy	Walter C Beckjord 3	128.0	Coal	DEOK	43	01-Oct-13
First Energy	Hatfield's Ferry 1	530.0	Coal	APS	42	09-Oct-13
First Energy	Hatfield's Ferry 2	530.0	Coal	APS	65	09-Oct-13
First Energy	Hatfield's Ferry 3	530.0	Coal	APS	50	09-Oct-13
First Energy	Mitchell 2	82.0	Coal	APS	08	09-Oct-13
First Energy	Mitchell 3	277.0	Coal	APS	21	09-Oct-13
Delmarva Power	Indian River 3	165.0	Coal	DPL	44	31-Dec-13
First Energy	Mad River CTs A	25.0	Diesel	ATSI	41	09-Jan-14
First Energy	Mad River CTs B	25.0	Diesel	ATSI	41	09-Jan-14
Total		2,912.6				

16 *See* "*PJM Generator Deactivations*," PJM.com <http://pjm.com/planning/generation-retirements/gr-summaries.aspx> (Accessed January 15, 2014).

Generation Mix

Currently, PJM has an installed capacity of 195,775 MW (Table 12-11) including non-derated solar and wind resources, as well as energy-only units.

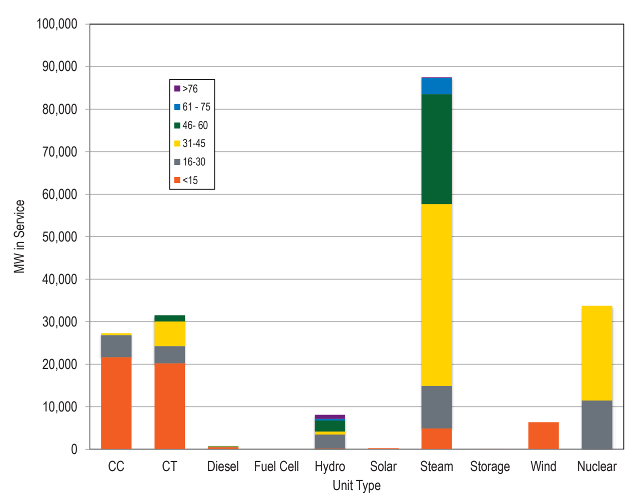
Table 12-11 Existing PJM capacity: At December 31, 2013[17] (By zone and unit type (MW))

Zone	CC	CT	Diesel	Fuel Cell	Hydroelectric	Nuclear	Solar	Steam	Storage	Wind	Total
AECO	164	706	23	0	0	0	40	1,087	0	8	2,026
AEP	4,900	3,682	63	0	1,072	2,071	0	21,145	0	1,753	34,686
APS	1,129	1,215	48	0	86	0	36	5,409	27	999	8,949
ATSI	685	1,667	73	0	0	2,134	0	6,540	0	0	11,099
BGE	0	835	18	0	0	1,716	0	2,996	0	0	5,565
ComEd	2,270	7,244	100	0	0	10,474	0	5,417	5	2,454	27,964
DAY	0	1,369	48	0	0	0	1	3,180	40	0	4,637
DEOK	0	842	0	0	0	0	0	3,932	0	0	4,774
DLCO	244	15	0	0	6	1,777	0	784	0	0	2,826
Dominion	4,030	3,875	154	0	3,589	3,581	3	8,403	0	0	23,634
DPL	1,125	1,820	96	30	0	0	4	1,635	0	0	4,711
EKPC	0	774	0	0	70	0	0	1,882	0	0	2,726
EXT	664	111	0	0	0	13	0	5,484	0	0	6,271
JCPL	1,693	1,233	16	0	400	615	45	10	0	0	4,011
Met-Ed	2,051	407	41	0	19	805	0	601	0	0	3,924
PECO	3,209	836	3	0	1,642	4,547	3	979	1	0	11,220
PENELEC	0	408	46	0	513	0	0	6,794	0	931	8,690
Pepco	230	1,092	10	0	0	0	0	3,649	0	0	4,981
PPL	1,808	616	49	0	707	2,520	15	5,529	20	220	11,483
PSEG	3,091	2,838	12	0	5	3,493	107	2,050	2	0	11,598
Total	27,292	31,584	799	30	8,109	33,745	253	87,504	95	6,364	195,775

Figure 12-2 shows the age of PJM generators by unit type. Units older than 30 years comprise 107,452 MW, or 54.8 percent, of the total capacity of 195,775 MW. Units older than 45 years comprise 35,359 MW, or 18.0 percent of the total capacity.

Table 12-12 shows the effect that the new generation in the queues would have on the existing generation mix, assuming that all non-hydroelectric generators in excess of 40 years of age in 2013 retire by 2024. The expected role of gas-fired generation depends largely on projects in the queues and continued retirement of coal-fired generation. The 79.3 percent of existing capacity in SWMAAC which is steam or nuclear would be reduced, by 2024, to 57.6 percent, and CC and CT generators would comprise 41.8 percent of total capability in SWMAAC.

Figure 12-2 PJM capacity (MW) by age (years): at December 31, 2013



17 The capacity described in this section refers to all installed capacity in PJM, regardless of whether the capacity entered the RPM auction.

In Non-MAAC zones, 81.3 percent of all generation 40 years or older, as of December 31, 2013, is steam, primarily coal.[18] If these older coal units retire and if all queued wind MW are built as planned, by 2020, wind farms would account for 12.1 percent of total ICAP MW in Non-MAAC zones.

Table 12-12 Comparison of generators 40 years and older with slated capacity additions (MW) through 2024, as of December 31, 2013[19]

Area	Unit Type	Capacity of Generators 40 Years or Older	Percent of Area Total	Capacity of Generators of All Ages	Percent of Area Total	Additional Capacity through 2024	Estimated Capacity 2024	Percent of Area Total
EMAAC	Combined Cycle	198	1.8%	9,282	27.7%	8,598	17,880	38.8%
	Combustion Turbine	3,764	34.0%	7,433	22.1%	436	7,870	17.1%
	Diesel	59	0.5%	150	0.4%	22	171	0.4%
	Fuel Cell	0	0.0%	30	0.1%	0	30	0.1%
	Hydroelectric	2,042	18.4%	2,047	6.1%	20	2,067	4.5%
	Nuclear	1,740	15.7%	8,654	25.8%	330	8,984	19.5%
	Solar	0	0.0%	198	0.6%	1,683	1,881	4.1%
	Steam	3,266	29.5%	5,761	17.2%	20	5,781	12.6%
	Storage	0	0.0%	3	0.0%	23	26	0.1%
	Wind	0	0.0%	8	0.0%	1,348	1,356	2.9%
	EMAAC Total	11,069	100.0%	33,566	100.0%	12,480	46,046	100.0%
SWMAAC	Combined Cycle	0	0.0%	230	1.6%	3,756	3,986	15.7%
	Combustion Turbine	964	19.0%	1,927	13.4%	256	2,183	8.6%
	Diesel	0	0.0%	28	0.2%	29	57	0.2%
	Hydroelectric	0	0.0%	1,716	11.9%	0	1,716	6.8%
	Nuclear	0	0.0%	0	0.0%	22	22	0.1%
	Solar	4,099	81.0%	6,645	46.1%	132	6,777	26.7%
	Steam	0	0.0%	3,859	26.8%	6,771	10,630	41.9%
	SWMAAC Total	5,063	100.0%	14,404	100.0%	10,966	25,370	100.0%
WMAAC	Combined Cycle	714	7.2%	1,430	7.1%	127	1,557	7.1%
	Combustion Turbine	46	0.5%	136	0.7%	46	182	0.8%
	Diesel	887	9.0%	1,238	6.1%	43	1,281	5.8%
	Hydroelectric	0	0.0%	3,325	16.4%	50	3,375	15.3%
	Nuclear	0	0.0%	15	0.1%	64	79	0.4%
	Solar	8,974	90.6%	12,923	63.9%	0	12,923	58.6%
	Steam	0	0.0%	20	0.1%	50	70	0.3%
	Storage	0	0.0%	1,151	5.7%	1,419	2,570	11.7%
	Wind	0	0.0%	0	0.0%	0	0	0.0%
	WMAAC Total	9,907	100.0%	20,238	100.0%	1,798	22,037	100.0%
Non-MAAC	Combined Cycle	0	0.0%	13,922	10.9%	20,296	34,217	20.2%
	Combustion Turbine	1,301	3.0%	20,794	16.3%	3,230	24,023	14.2%
	Diesel	72	0.2%	485	0.4%	128	613	0.4%
	Hydroelectric	1,433	3.3%	4,824	3.8%	201	5,024	3.0%
	Nuclear	5,296	12.3%	20,049	15.7%	1,816	21,865	12.9%
	Solar	0	0.0%	40	0.0%	200	240	0.1%
	Steam	34,999	81.2%	62,175	48.7%	650	62,825	37.0%
	Storage	0	0.0%	72	0.1%	239	311	0.2%
	Wind	0	0.0%	5,206	4.1%	15,295	20,502	12.1%
	Non-MAAC Total	43,100	100.0%	127,566	100.0%	42,055	169,621	100.0%
All Areas	Total	69,139		195,775		67,299	263,074	

18 Non-MAAC zones consist of the AEP, AP, ATSI, ComEd, DAY, DEOK, DLCO, and Dominion control zones

19 Percentages shown in Table 12-12 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

2012 Changes to the Open Access Transmission Tariff (OATT)

PJM established the Interconnection Process Senior Task Force (IPSTF) in February 2011 to address stakeholder concerns about the project queues and study turnaround delays. The IPSTF categorized the main causes for delays in its queue process into two types: "the sheer number of projects, including hundreds of small projects and a few very large projects in its queue; and the number of restudies that were required when projects drop out or reduced size."[20]

The following changes were proposed and accepted to address these concerns: Queue cycles went back to a six-month duration; sliding queues were established for certain projects that seek to modify the size of their Interconnection Requests; and an alternate queue for projects less than 20 MW was established. Other changes included reducing suspension rights if the suspension will negatively impact the timing or cost of a subsequent queue projects and clarifying the timeframe for notifying PJM if a project is transferring Capacity Interconnection Rights (CIRs) from a deactivating generator.[21]

These changes went into effect on May 1, 2012.[22] As of December 31, 2013, 34 queue projects, totaling 309.0 MW, have been assigned to the alternate queue. The impact of these changes is difficult to quantify. Table 12-13 shows an increase in new projects in 2010 and 2011, and an increase in withdrawals in 2011 and 2012. The subsequent and significant drop in queue activity in 2012 and 2013 would have likely eased the congestion and burden of completing the studies even without any changes to the tariff. Nonetheless, there is still a backlog in project study completion, as well as other issues, which warrant further analysis of the study process.

20 *See* letter from PJM to Secretary Kimberly Bose <http://www.pjm.com/~/media/documents/ferc/2012-filings/20120229-er12-1177-000.ashx>. (Accessed December 4, 2013)

21 *Id.*

22 *See* PJM. Manual 14A. "Generation and Transmission Interconnection Process," <http://www.pjm.com/~/media/documents/manuals/m14a.ashx>.

Table 12-13 Projects added and withdrawn by year

Year	Projects Added	Projects Withdrawn
2005	110	53
2006	146	44
2007	219	36
2008	216	81
2009	174	106
2010	441	135
2011	356	249
2012	157	271
2013	153	176

Overview of the Planning Process

Table 12-14 shows an overview of PJM's study process. In addition to these steps, system impact and facilities studies are often redone, or retooled, when a project is withdrawn because withdrawals may affect the investments of the projects remaining in the queue.

PJM's Manual 14A states that it can take up to 739 days in addition to the (unspecified) time it takes to complete the facilities study to obtain an interconnection construction service agreement (ICSA). It further states that a feasibility study should take no longer than 334 days.[23]

Table 12-15, presents information on actual time in the stages of the queue. For the 372 active projects in the queue as of December 31, 2013, 52 had reached the milestone of feasibility study completion. On average, the time it took to complete the feasibility study was close to PJM's estimate of 334 days. However, completion time for 20 of the 52 projects at this milestone exceeded this estimate, with five of them in the queue over 500 days. PJM Manual 14A also states that a system impact study should take no longer than 514 days. Table 12-15 shows that for the 166 projects that are at this milestone, the system impact studies have taken an average of 1,280 days, with 25 of the 166 studies in the queue for over 2,000 days.

Analysis of projects in the active queues in stages of the study process show that 39.0 percent of the active projects in the queue are waiting for the results of the system impact study. At the same time, 42.7 percent of the projects withdrawn were done so after the system impact study was completed. Another 40.1 percent of the projects were withdrawn after the facility study was completed.

23 See PJM. Manual 14A. "Generation and Transmission Interconnection Process," p.29, <http://www.pjm.com/~/media/documents/manuals/m14a.ashx>.

Table 12-14 PJM generation planning process[24]

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

Table 12-15 PJM generation planning summary: at December 31, 2013

Milestone Completed	Number of Projects in Queue	Percent of Total Projects in Queue	Maximum Days in Queue	Average Days in Queue
Not Started	93	25.0%	432	110
Feasibility Study	52	14.0%	616	355
System Impact Study	166	44.6%	3,087	1,280
Facility Study	25	6.7%	2,352	1,291
ISA	1	0.3%	1,589	1,589
CSA	35	9.4%	3,227	1,767
Total	372			

Backbone Facilities

PJM baseline upgrade projects are implemented to resolve reliability criteria violations. 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 EHV (extra high voltage) system and resolve a wide range of reliability criteria violations and market congestion issues. The current backbone projects are Mount Storm-Doubs, Jacks Mountain, and Susquehanna-Roseland.

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 in its service areas. As of January 2014, construction is ahead of schedule.[25]

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. The plans are for construction of the foundation in late 2013, construction in 2014 and completion in early 2015.

The Susquehanna-Roseland project is required to resolve reliability criteria violations starting June 1, 2012. Susquehanna-Roseland will be a new 500 kV transmission line connecting the Susquehanna – Lackawanna – Hopatcong – Roseland buses. The Susquehanna-Hopatcong portion of the project is currently expected to be in-service by June 2014, with the remainder of the project to be completed by June, 2015.

24 Other agreements may also be required, e.g. Interconnection Construction Service Agreement (ICSA), Upgrade Construction Service Agreement (UCSA). See "PJM Manual 14C: Generation and Transmission Interconnection Process," p.29, <http://www.pjm.com/~/media/documents/manuals/m14c.ashx>.

25 See "*Mt. Storm-Doubs 500kV Rebuild Project*," Dom.com <https://www.dom.com/about/electric-transmission/mtstorm/index.jsp> (January 15, 2014).

Regional Transmission Expansion Plan (RTEP)

The PJM Board of Managers authorized $1.2 billion on October 3, 2013, and $5.9 billion on December 11, 2013, in baseline and network transmission upgrades and improvements that were identified as part of PJM's continued regional planning process. Table 12-16 shows the upgrades by transmission owner and upgrade type. This brings the total currently approved expenditures to $28.9 billion.

Table 12-16 Estimated approved upgrade costs by transmission owner and upgrade type (dollars (Millions)

Transmission Owner	Baseline	Network
AECO	$0.0	$39.8
AEP	$86.3	$1,481.5
APS	$60.4	$123.2
ATSI	$0.6	$136.7
BGE	$18.0	$0.4
ComEd	$30.3	$1,767.8
DAY	$0.0	$45.1
DEOK	$0.0	$4.2
DLCO	$0.0	$2.3
Dominion	$16.1	$10.6
DPL	$1.6	$51.0
Essential Power	$0.0	$0.9
EKPC	$4.9	$0.0
JCPL	$0.9	$0.8
Met-Ed	$0.0	$208.0
NRG Energy	$0.0	$0.0
PECO	$1.0	$0.0
PENELEC	$1.7	$34.2
Pepco	$6.8	$56.8
PPL	$68.6	$371.4
PSEG	$1,242.2	$12.2
Total	$1,539.3	$4,346.9

RTEP Proposal Windows

On July 22, 2013, PJM made a second filing in compliance with Order No. 1000 and in compliance with the order on its first compliance filing issued March 22, 2013.[26] PJM's Order No. 1000 compliance filing addressed a number of procedural issues identified by the Commission in the March 22 order. In the initial filing, PJM proposed to expand the regional planning process to provide greater opportunity for non-incumbent transmission developers to submit solution proposals.[27] PJM's filing established proposal windows for competitive solicitations, but limited the ability of competitors to make proposals within a defined time window.[28]

A test of whether PJM's new process can operate transparently and offer a meaningful opportunity for non-incumbents to compete involves Artificial Island, which includes the Salem and Hope Creek nuclear plants. On April 29, 2013, PJM submitted a request for proposal (RFP), seeking technical solutions to improve stability issues, operational performance under a range of anticipated system conditions, and to eliminate potential planning criteria violations in the Artificial Island Area. The RFP window closed on June 28, 2013. PJM received 26 individual proposals from seven entities, including proposals from the incumbent transmission owner, PSEG, and a range of proposals from other non-incumbents. The costs of solutions proposed ranged from approximately $54 million to $1.4 billion.[29] These proposals are currently being evaluated by PJM.

Economic Planning Process

A goal of transmission planning should be the incorporation of transmission investment decisions into market driven processes as much as possible. Transmission investments have not been fully incorporated into competitive markets. The PJM economic planning process could enhance competition in PJM to build projects, to finance projects and to meet load without building new generation.

Competition to Build

On its own initiative and in compliance with Order No. 1000, PJM introduced limited opportunities for non-incumbent transmission owners to compete with incumbent transmission owners to identify and sponsor the development of projects in the PJM region for economic reasons.[30] The rules accord no right of first refusal to incumbents.[31] The efficacy of these rules may be limited by requirements that may favor incumbents, such as those based on ownership of existing infrastructure and rights of way and procedures that fail to provide adequate incentive to nonincumbents to

26 PJM Interconnection, L.L.C., Compliance Filing, Docket No. ER13-198-002 (July 22, 2013) (July 22nd PJM Filing"); 142 FERC ¶ 61,214. PJM transmission owners made a separate filing addressing cost allocation issues, also on March 22, 2013.

27 PJM Interconnection, L.L.C., Compliance Filing Docket No. ER13-198-000 (October 25, 2012). Originally filed under Docket No. RM 10-123-000, in compliance with FERCs Order No. 1000, Transmission Planning and Cost Allocation By Transmission Owning and Operating Public Utilities.

28 *Id.*; see also "*RTEP Proposal Windows*," PJM.com <http://www.pjm.com/planning/rtep-development/expansion-plan-process/ferc-order-1000/rtep-proposal-windows.aspx>.

29 *See* "*PJM 2013 RTEP Proposal Window Tracking*," PJM.com <http://www.pjm.com/~/media/committees-groups/committees/teac/20130710/20130710-pjm-2013-rtep-proposal-window-tracking.ashx>.

30 *See* FERC Docket No. ER13-198; 145 FERC ¶ 61,214.

31 *See* 145 FERC ¶ 61,214 at PP 221–234.

identify locations on the system that could be enhanced with economic projects. The Commission has ordered and PJM has filed on compliance changes that would significantly narrow incumbents' advantages based on whether the project is an upgrade to an existing facility or requires access to an incumbent's right of way.[32] PJM also details a process that may afford protection to nonincumbents not available in the Primary Power matter.[33] An order on compliance is pending.

Competition to Finance

A feature of competitive transmission development that is as significant as ensuring competition to build is the potential to reduce the costs to customers of investment in transmission through competition to finance.

Under the current rules, non-incumbents and incumbents compete to develop projects for the same regulated rate of return, some including incentive adders.

An alternative approach would introduce competition to find the lowest cost source of capital. A competitive process would ensure that customers pay market rates of return.

Competition to provide financing could reduce the cost of capital for transmission projects and significantly reduce total costs to customers. The MMU recommended this approach in PJM's proceeding on compliance with Order No. 1000 and continues to recommend that PJM implement this approach.[34]

Competition to Meet Load

Transmission investments have not been fully incorporated into competitive markets. The construction of new transmission facilities can have significant impacts on energy and capacity markets, but there is no market mechanism in place that would require direct competition between transmission and generation to meet loads in an area. PJM has taken a first step towards integrating transmission investments into the market through the use of economic evaluation metrics and through the ability to offer transmission projects in RPM auctions.[35, 36] The goal of transmission planning should be the incorporation of transmission investment decisions into market driven processes as much as possible.

32 *Id.* at PP 227, 229, 231.

33 *Id.* at PP 37–48; OA Schedule 6 § 1.5.7; see also 140 FERC ¶ 61,054 (2012).

34 Comments of the Independent Market Monitor for PJM, Docket No. ER13-198 (December 10, 2012) at 4–7; 145 FERC ¶ 61,214 at P 268, 281.

35 *See* 126 FERC ¶ 61,152 (2009) (final approval for an approach with predefined formulas for determining whether a transmission investment passes the cost-benefit test including explicit accounting for changes in production costs, the costs of complying with environmental regulations, generation availability trends and demand-response trends), *order on reh'g*, 123 FERC ¶ 61,051 (2008).

36 *See*, e.g., OATT Attachment DD § 5.6.4 (Qualifying Transmission Upgrades). To date, no Qualifying Transmission Upgrade has cleared RPM.