Generation and Transmission Planning

Overview

Planned Generation and Retirements

- **Planned Generation.** At December 31, 2012, 76,387 MW of capacity were in generation request queues for construction through 2018, compared to an average installed capacity of 185,000 MW in 2012 including the January 1, 2012, DEOK integration. Wind projects account for approximately 21,359 MW of nameplate capacity, 28.0 percent of the MW in the queues, and combined-cycle projects account for 42,724 MW, 55.8 percent of the MW in the queues.
- **Generation Retirements.** A total of 7,130.9 MW of generation capacity retired from January 1, 2012 through January 1, 2013, and it is expected that a total of 21,524.9 MW will have retired from 2011 through 2019, with most of this capacity retiring by the end of 2015. Retirements from January 1, 2011 through January 1, 2013, account for 8,453.2 MW. Units planning to retire in 2013 account for 237.4 MW, or 1.1 percent of planned retirements during this period. Overall, 3,951.1 MW, or 18.4 percent of all retirements from 2011 through 2019, are expected in the AEP 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 EMAAC and SWMAAC LDAs, the capacity mix is likely to shift to more natural gas-fired combined cycle (CC) and combustion turbine (CT) capacity. 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 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 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, including 7,584.2 MW that should already be in service based on the original queue date, but that is not yet even under construction. These projects may also create barriers to entry for projects that would otherwise be completed by taking up queue positions, increasing interconnection costs and creating uncertainty.

Key Backbone Facilities

- PJM baseline transmission projects are implemented to resolve reliability criteria violations. PJM backbone transmission projects are a subset of significant baseline projects. The backbone projects are intended to resolve a wide range of reliability criteria violations and congestion issues and have substantial impacts on energy and capacity markets. The current backbone projects are: Mount Storm – Doubs; Jacks Mountain; and Susquehanna – Roseland. The total planned costs for all of these projects are approximately 1.7 billion dollars.

Economic Planning Process

- **Transmission and Markets.** As a general matter, 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.[2] The goal of transmission planning should be the incorporation of transmission investment decisions into market driven processes as much as possible.

1 OATT Parts IV & VI.

2 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).

- **Competitive Grid Development.** In Order No. 1000, the FERC requires that each public utility transmission provider (including PJM) remove from its FERC approved tariff and agreements, as necessary and subject to certain limitations, a federal right of first refusal (ROFR) for certain new transmission projects.[3,4] A key limitation is the ability to retain ROFR for upgrades to the existing transmission infrastructure.

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 1000, there is not yet a robust mechanism to permit competition between transmission developers to build transmission projects. 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 evaluation of whether the generation or transmission alternative is less costly or who bears the risks associated with each alternative. Creating such a mechanism should be a goal of PJM market design.

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. At December 31, 2012, 76,387 MW of capacity were in generation request queues for construction through 2018, compared to an average installed capacity of 185,000 MW in 2012 including the January 1, 2012, DEOK integration. Although it is clear that not all generation in the queues will be built, PJM has added capacity annually since 2000 (Table 11-1).[5] Overall, 2,669 MW of nameplate capacity were added in PJM in 2012 (excluding the integration of the DEOK zone).

Table 11-1 Year-to-year capacity additions from PJM generation queue: Calendar years 2000 through 2012[6]

	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

PJM Generation Queues

Generation request queues are groups of proposed projects. Queue A was open from February 1997 through January 1998; Queue B was open from February 1998 through January 1999; Queue C was open from February 1999 through July 1999 and Queue D opened in August 1999. After Queue D, a new queue was opened every six months until Queue T, when new queues began to open annually. Queue Y will be active through January 31, 2013.

Capacity in generation request queues for the seven year period beginning in 2012 and ending in 2018 decreased by 14,338 MW from 90,725 MW in 2011 to 76,387 MW in 2012, or 15.8 percent (Table 11-2).[7] Queued capacity scheduled for service in 2012 decreased from 27,184 MW to 12,301 MW, or 54.7 percent, though only 2,669 MW

3 *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, FERC Stats. & Regs. ¶31,323 (2011).

4 *Id.* at PP 313–322.

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

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

7 See the *2011 State of the Market Report for PJM*: Volume II, Section 11, pp. 286-288, for the queues in 2011.

went into service in 2012. Queued capacity scheduled for service in 2013 decreased from 13,051 MW to 9,819 MW, or 24.8 percent. The 76,387 MW include generation with scheduled in-service dates in 2012 and units still active in the queue with in-service dates scheduled before 2012, listed at nameplate capacity, although these units are not yet in service.

Table 11-2 Queue comparison (MW): December 31, 2012 vs. December 31, 2011

	MW in the Queue 2011	MW in the Queue 2012	Year-to-Year Change (MW)	Year-to-Year Change
2012	27,184	12,301	(14,883)	(54.7%)
2013	13,051	9,819	(3,232)	(24.8%)
2014	17,036	8,086	(8,950)	(52.5%)
2015	19,251	22,295	3,044	15.8%
2016	9,288	11,788	2,500	26.9%
2017	1,720	8,932	7,212	419.3%
2018	3,194	3,165	(29)	(0.9%)
Total	90,725	76,387	(14,338)	(15.8%)

Table 11-3 shows the amount of capacity active, in-service, under construction 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.[8]

Table 11-3 Capacity in PJM queues (MW): At December 31, 2012[9,10]

Queue	Active	In-Service	Under Construction	Withdrawn	Total
A Expired 31-Jan-98	0	8,103	0	17,347	25,450
B Expired 31-Jan-99	0	4,646	0	14,957	19,602
C Expired 31-Jul-99	0	531	0	3,471	4,002
D Expired 31-Jan-00	0	851	0	7,182	8,033
E Expired 31-Jul-00	0	795	0	8,022	8,817
F Expired 31-Jan-01	0	52	0	3,093	3,145
G Expired 31-Jul-01	0	1,116	525	17,409	19,050
H Expired 31-Jan-02	0	703	0	8,422	9,124
I Expired 31-Jul-02	0	103	0	3,728	3,831
J Expired 31-Jan-03	0	40	0	846	886
K Expired 31-Jul-03	0	218	80	2,345	2,643
L Expired 31-Jan-04	0	257	0	4,034	4,290
M Expired 31-Jul-04	0	505	422	3,556	4,482
N Expired 31-Jan-05	0	2,399	38	8,090	10,527
O Expired 31-Jul-05	10	1,491	1,025	5,066	7,592
P Expired 31-Jan-06	413	2,915	455	4,908	8,690
Q Expired 31-Jul-06	120	2,038	2,914	9,462	14,534
R Expired 31-Jan-07	1,426	1,216	778	19,334	22,755
S Expired 31-Jul-07	1,778	3,243	652	11,469	17,142
T Expired 31-Jan-08	4,140	1,259	631	21,516	27,546
U Expired 31-Jan-09	3,532	666	132	29,026	33,357
V Expired 31-Jan-10	5,626	259	1,626	9,494	17,005
W Expired 31-Jan-11	8,430	301	1,741	13,785	24,256
X Expired 31-Jan-12	17,882	80	2,028	10,396	30,386
Y Expires 31-Jan-13	19,852	0	132	947	20,931
Total	63,208	33,785	13,179	237,903	348,075

Data presented in Table 11-4 show that through 2012, 37.7 percent of total in-service capacity from all the queues was from Queues A and B and an additional 6.4

8 Projects listed as active have been entered in the queue and the next phase can be under construction, in-service or withdrawn. At any time, the total number of projects in the queues is the sum of active projects and under-construction projects.

9 The *2012 State of the Market Report for PJM* contains all projects in the queue including reratings of existing generating units and energy only resources.

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

percent was from Queues C, D and E.[11] As of December 31, 2012, 31.8 percent of the capacity in Queues A and B has been placed in service, and 9.7 percent of all queued capacity has been placed in service.

The data presented in Table 11-4 show that for successful projects there is an average time of 831 days between entering a queue and the in-service date, an increase of 29 days since 2011. The data also show that for withdrawn projects, there is an average time of 543 days between entering a queue and completion or exiting. For each status, there is substantial variability around the average results.

Table 11-4 Average project queue times (days): At December 31, 2012

Status	Average (Days)	Standard Deviation	Minimum	Maximum
Active	882	634	0	2,801
In-Service	831	710	0	3,964
Suspended	2,155	922	704	3,849
Under Construction	1,412	785	0	5,083
Withdrawn	543	556	0	3,186

Table 11-5 shows active queued capacity that was planned to be in service by January 1, 2013. This indicates there is a substantial amount of queued capacity, 7,584.2 MW, that should already be in service based on the original queue date but that is not yet even under construction. The MMU recommends that a review process be created to ensure that projects are removed from the queue, if they are no longer viable and no longer planning to complete the project.

Table 11-5 Active capacity queued to be in service prior to January 1, 2013

	MW
2007	87.0
2008	347.0
2009	296.4
2010	2,160.5
2011	3,639.2
2012	1,054.1
Total	7,584.2

Distribution of Units in the Queues

A more detailed examination of the queue data permits some additional conclusions. 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. At December 31, 2012, 76,387 MW of capacity were in generation request queues for construction through 2018, compared to an average installed capacity of 185,000 MW in 2012 including the January 1, 2012, DEOK integration. Wind projects account for 21,359 MW of nameplate capacity or 28.0 percent of the capacity in the queues and combined-cycle projects account for 42,724 MW of capacity or 55.9 percent of the capacity in the queues.[12] On December 31, 2012, there were 42,724 MW of capacity from combined cycle units in the queue, compared to 34,788 MW in 2011, an increase of 22.8 percent. At December 31, 2012, there was queued combined cycle capacity in nearly every zone in PJM, and after accounting for the derating of wind and solar resources, combined cycle capacity comprises 75.9 percent of the MW in the queue able to offer into RPM auctions.

Table 11-6 shows the projects under construction or active as of December 31, 2012, by unit type and control zone. Most of the steam projects (99.4 percent of the MW) and most of the wind projects (93.8 percent of the MW) are outside the Eastern MAAC (EMAAC)[13] and Southwestern MAAC (SWMAAC)[14] locational deliverability areas (LDAs).[15] Of the total capacity additions, only 15,323 MW, or 20.1 percent, are projected to be in EMAAC, while 4,225 MW or 5.5 percent are projected to be constructed in SWMAAC. Of total capacity additions, 29,272 MW, or 38.3 percent of capacity, is being added inside MAAC zones. Overall, 74.4 percent of capacity is being added outside EMAAC and SWMAAC, and 61.6 percent of capacity is being added outside MAAC zones, not accounting for the planned integration of the EKPC zone in 2013. Wind projects account for 2,933 MW of capacity in MAAC LDAs, or 10.0 percent. While there are no wind projects in the SWMAAC LDA, in the EMAAC LDA wind projects account for 1,319 MW of capacity, or 8.6 percent.

11 The data for Queue Y include projects through September 30, 2012.

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. PJM derates solar resources to 38 percent of installed capacity. Based on the derating of 21,359 MW of wind resources and 2,447 MW of solar resources, the 76,387 MW currently active in the queue would be reduced to 56,288 MW.

13 EMAAC consists of the AECO, DPL, JCPL, PECO and PSEG Control Zones.

14 SWMAAC consists of the BGE and Pepco Control Zones.

15 See the *2012 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography" for a map of PJM LDAs.

Table 11-6 Capacity additions in active or under-construction queues by control zone (MW): At December 31, 2012

	CC	CT	Diesel	Hydro	Nuclear	Solar	Steam	Storage	Wind	Total
AECO	3,495	63	9	0	0	516	0	0	1,069	5,152
AEP	6,124	0	13	70	0	104	2,069	84	10,628	19,091
AP	2,044	0	33	75	0	143	918	0	526	3,739
ATSI	3,851	40	10	0	30	22	135	0	849	4,937
BGE	678	256	4	0	0	22	0	0	0	960
ComEd	1,440	444	102	23	607	65	600	42	4,959	8,282
DAY	0	0	2	112	0	23	12	12	845	1,006
DEOK	20	0	0	0	0	0	0	0	0	20
DLCO	245	0	0	0	91	0	0	0	0	336
Dominion	6,501	535	11	0	1,594	80	364	0	619	9,703
DPL	1,223	2	0	0	0	270	22	0	230	1,746
JCPL	2,550	0	30	0	0	883	0	0	0	3,463
Met-Ed	1,818	0	18	0	58	3	0	0	0	1,897
PECO	114	7	4	0	470	10	0	5	0	609
PENELEC	879	43	231	0	0	32	106	0	1,194	2,485
Pepco	3,245	0	20	0	0	0	0	0	0	3,265
PPL	4,716	0	10	3	100	74	0	20	420	5,342
PSEG	3,783	290	9	0	50	200	0	2	20	4,353
Total	42,724	1,680	505	283	3,000	2,447	4,225	164	21,359	76,387

Table 11-7 Capacity additions in active or under-construction queues by LDA (MW): At December 31, 2012[16]

	CC	CT	Diesel	Hydro	Nuclear	Solar	Steam	Storage	Wind	Total
EMAAC	11,164	362	52	0	520	1,879	22	7	1,319	15,323
SWMAAC	3,923	256	24	0	0	22	0	0	0	4,225
WMAAC	7,413	43	258	3	158	109	106	20	1,614	9,724
Non-MAAC	20,225	1,019	171	280	2,322	437	4,098	138	18,426	47,115
Total	42,724	1,680	505	283	3,000	2,447	4,225	164	21,359	76,387

There are potentially significant implications for future congestion, the role of firm and interruptible gas supply and natural gas supply infrastructure, if older steam units are replaced by units burning natural gas. (Table 11-7)

Table 11-8 shows existing generation by unit type and control zone. Existing steam (mainly coal and residual oil) and nuclear capacity is distributed across control zones.

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 11-6) 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.

16 WMAAC consists of the Met-Ed, PENELEC, and PPL Control Zones.

Table 11-8 Existing PJM capacity: At January 1, 2013[17] (By zone and unit type (MW))

	CC	CT	Diesel	Fuel Cell	Hydroelectric	Nuclear	Solar	Steam	Storage	Wind	Total
AECO	164	701	21	0	0	0	40	1,087	0	8	2,020
AEP	4,900	3,682	60	0	1,072	2,071	0	21,512	0	1,753	35,050
AP	1,129	1,215	48	0	80	0	36	7,358	27	999	10,892
ATSI	685	1,661	71	0	0	2,134	0	6,540	0	0	11,091
BGE	0	835	11	0	0	1,716	0	3,007	0	0	5,569
ComEd	1,763	7,257	94	0	0	10,438	0	5,417	5	2,454	27,427
DAY	0	1,369	48	0	0	0	1	4,368	0	0	5,785
DEOK	0	842	0	0	0	0	0	2,646	0	0	3,488
DLCO	244	15	0	0	6	1,777	0	784	0	0	2,826
Dominion	4,030	3,762	174	0	3,589	3,581	3	8,320	0	0	23,458
DPL	1,125	1,820	96	30	0	0	4	1,800	0	0	4,876
External	974	990	0	0	66	439	0	5,728	0	185	8,382
JCPL	1,693	1,233	27	0	400	615	42	15	0	0	4,024
Met-Ed	2,051	408	41	0	20	805	0	844	0	0	4,168
PECO	3,209	836	3	0	1,642	4,547	3	979	1	0	11,220
PENELEC	0	344	46	0	513	0	0	6,831	0	931	8,663
Pepco	230	1,092	12	0	0	0	0	3,649	0	0	4,983
PPL	1,804	617	49	0	582	2,520	15	5,537	0	220	11,342
PSEG	3,091	2,838	12	0	5	3,493	105	2,052	0	0	11,597
Total	27,091	31,515	811	30	7,974	34,135	249	88,473	33	6,549	196,860

Table 11-9 shows the age of PJM generators by unit type.

Table 11-9 PJM capacity (MW) by age: at January 1, 2013

Age (years)	Combined Cycle	Combustion Turbine	Diesel	Fuel Cell	Hydroelectric	Nuclear	Solar	Steam	Storage	Wind	Total
Less than 11	18,993	9,253	459	30	11	0	249	2,482	33	6,515	38,025
11 to 20	6,062	13,070	106	0	48	0	0	3,261	0	34	22,582
21 to 30	1,594	1,663	56	0	3,448	15,409	0	8,504	0	0	30,674
31 to 40	244	3,108	43	0	105	16,361	0	28,696	0	0	48,557
41 to 50	198	4,420	132	0	2,915	2,365	0	29,339	0	0	39,369
51 to 60	0	0	15	0	379	0	0	13,516	0	0	13,910
61 to 70	0	0	0	0	0	0	0	2,526	0	0	2,526
71 to 80	0	0	0	0	280	0	0	95	0	0	375
81 to 90	0	0	0	0	549	0	0	54	0	0	603
91 to 100	0	0	0	0	155	0	0	0	0	0	155
101 and over	0	0	0	0	84	0	0	0	0	0	84
Total	27,091	31,515	811	30	7,974	34,135	249	88,473	33	6,549	196,860

Table 11-10 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 retire by 2018. The expected role of gas-fired generation depends largely on projects in the queues and continued retirement of coal-fired generation. New gas-fired capability would represent 88.7 percent of all new capacity in EMAAC when the derating of wind and solar capacity is reflected.

In 2012, a planned addition of 1,640 MW of nuclear capacity to Calvert Cliffs in SWMAAC was withdrawn from the queue. Without the planned nuclear capability in SWMAAC, new gas-fired capability represents 98.9 percent of all new capability in the SWMAAC. In 2018, this would mean that CC and CT generators would comprise 55.0 percent of total capability in SWMAAC.

In Non-MAAC zones, if older units retire, a substantial amount of coal-fired generation would be replaced by wind generation if the units in the generation queues are constructed.[18] In these zones, 87.8 percent of all generation 40 years or older is steam (primarily coal). With the retirement of these units in 2018, wind farms would comprise 16.8 percent of total MW ICAP in Non-MAAC zones, if all queued MW are built.

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

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

Table 11-10 Comparison of generators 40 years and older with slated capacity additions (MW): Through 2018[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 2018	Estimated Capacity 2018	Percent of Area Total
EMAAC	Combined Cycle	198	2.4%	9,282	27.5%	11,164	20,248	48.7%
	Combustion Turbine	2,229	27.5%	7,428	22.0%	362	5,561	13.4%
	Diesel	48	0.6%	159	0.5%	52	163	0.4%
	Fuel Cell	0	0.0%	30	1.6%	0	30	1.8%
	Hydroelectric	2,042	25.2%	2,047	6.1%	0	620	1.5%
	Nuclear	615	7.6%	8,654	25.7%	520	8,560	20.6%
	Solar	0	0.0%	194	0.6%	1,879	2,073	5.0%
	Steam	2,981	36.7%	5,933	17.6%	22	2,974	7.2%
	Storage	0	0.0%	1	0.0%	7	8	0.0%
	Wind	0	0.0%	8	0.0%	1,319	1,327	3.2%
	EMAAC Total	8,112	100.0%	33,736	100.0%	15,323	41,562	100.0%
SWMAAC	Combined Cycle	0	0.0%	230	2.2%	3,923	4,153	39.4%
	Combustion Turbine	542	12.8%	1,927	18.3%	256	1,640	15.6%
	Diesel	0	0.0%	23	0.2%	24	47	0.4%
	Nuclear	0	0.0%	1,716	16.3%	0	1,716	16.3%
	Solar	0	0.0%	0	0.0%	22	22	0.2%
	Steam	3,702	87.2%	6,656	63.1%	0	2,954	28.0%
	SWMAAC Total	4,244	100.0%	10,552	100.0%	4,225	10,533	100.0%
WMAAC	Combined Cycle	0	0.0%	3,855	15.9%	7,413	11,268	78.7%
	Combustion Turbine	558	6.1%	1,368	5.7%	43	854	6.0%
	Diesel	46	0.5%	136	0.6%	259	348	2.4%
	Hydroelectric	887	9.7%	1,114	4.6%	3	1,117	7.8%
	Nuclear	0	0.0%	3,325	13.8%	158	3,483	24.3%
	Solar	0	0.0%	15	0.1%	109	124	0.9%
	Steam	7,702	83.8%	13,211	54.7%	106	5,616	39.2%
	Storage	0	0.0%	0	0.0%	20	20	0.1%
	Wind	0	0.0%	1,151	4.8%	1,614	2,764	19.3%
	WMAAC Total	9,193	100.0%	24,174	100.0%	9,724	14,325	100.0%
Non-MAAC	Combined Cycle	0	0.0%	13,724	10.7%	20,225	33,949	24.0%
	Combustion Turbine	1,092	3.1%	20,792	16.2%	1,019	20,719	14.6%
	Diesel	53	0.1%	494	0.4%	171	612	0.4%
	Hydroelectric	1,433	4.0%	4,814	3.7%	280	5,093	3.6%
	Nuclear	1,751	4.9%	20,440	15.9%	2,322	21,011	14.9%
	Solar	0	0.0%	40	0.0%	437	477	0.3%
	Steam	31,146	87.8%	62,672	48.8%	4,098	35,624	25.2%
	Storage	0	0.0%	32	0.0%	138	170	0.1%
	Wind	0	0.0%	5,391	4.2%	18,426	23,817	16.8%
	Non-MAAC Total	35,473	100.0%	128,398	100.0%	47,115	141,473	100.0%
All Areas	Total	57,022		196,860		76,387	207,892	

19 Percentages shown in Table 11-10 are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

Planned Deactivations

As shown in Table 11-11, 21,524.9 MW are planning to deactivate by the end of calendar year 2019. A total of 7,130.9 MW of generation capacity retired from January 1, 2012 through January 1, 2013, and it is expected that a total of 21,524.9 MW will have retired from 2011 through 2019, with most of this capacity retiring by the end of 2015. Retirements from January 1, 2011 through January 1, 2013, account for 8,453.2 MW, or 39.3 percent of retirements during this period. Units planning to retire in 2013 account for 237.4 MW, or 1.1 percent of retirements during this period. Overall, 3,951.1 MW, or 18.4 percent of all retirements from 2011 through 2019, are expected in the AEP zone.

Table 11-11 Summary of PJM unit retirements (MW): 2011 through 2019

	MW
Retirements 2011	1,322.3
Retirements 2012	6,961.9
Retirements 2013	169.0
Planned Retirements 2013	237.4
Planned Retirements Post-2013	12,834.3
Total	21,524.9

Figure 11-1 Unit retirements in PJM: 2012 through 2019

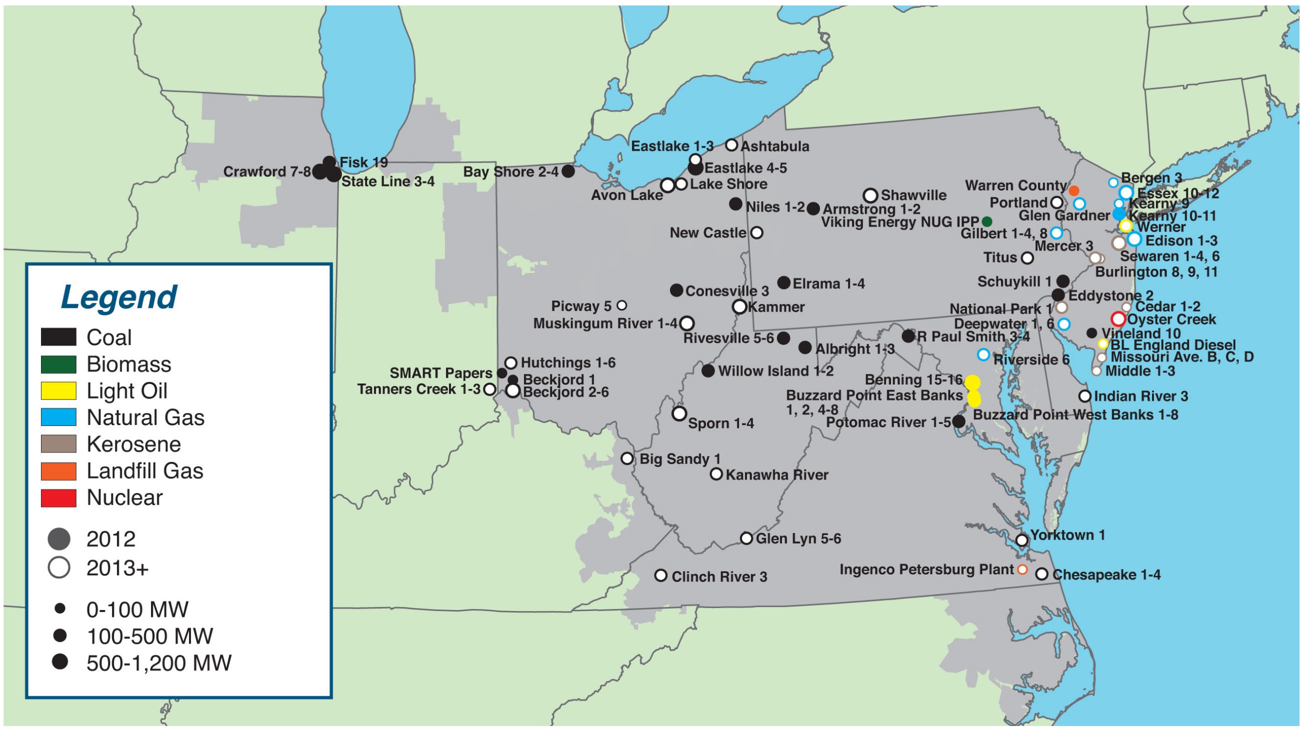

Table 11-12 Planned deactivations of PJM units after 2012, as of March 1, 2013

Unit	Zone	MW	Projected Deactivation Date
Warren County Landfill	JCPL	2.9	09-Jan-13
Ingenco Petersburg Plant	Dominion	2.9	31-May-13
Hutchings 4	DAY	61.9	01-Jun-13
Indian River 3	DPL	169.7	31-Dec-13
Riverside 6	BGE	115.0	01-Jun-14
Burlington 9	PSEG	184.0	01-Jun-14
Chesapeake 1-2	Dominion	222.0	31-Dec-14
Yorktown 1-2	Dominion	323.0	31-Dec-14
Portland	Met-Ed	401.0	07-Jan-15
Beckjord 2-6	DEOK	1,024.0	01-Apr-15
Avon Lake	ATSI	732.0	16-Apr-15
New Castle	ATSI	330.5	16-Apr-15
Titus	Met-Ed	243.0	16-Apr-15
Shawville	PENELEC	597.0	16-Apr-15
Gilbert 1-4, 8	JCPL	188.0	01-May-15
Glen Gardner	JCPL	160.0	01-May-15
Werner 1-4	JCPL	212.0	01-May-15
Kearny 9	PSEG	21.0	01-May-15
Cedar 1-2	AECO	67.7	31-May-15
Deepwater 1, 6	AECO	158.0	31-May-15
Middle 1-3	AECO	74.7	31-May-15
Missouri Ave B, C, D	AECO	60.0	31-May-15
Essex 12	PSEG	184.0	31-May-15
Big Sandy 2	AEP	278.0	01-Jun-15
Clinch River 3	AEP	230.0	01-Jun-15
Glen Lyn 5-6	AEP	325.0	01-Jun-15
Kammer	AEP	600.0	01-Jun-15
Kanawha River	AEP	400.0	01-Jun-15
Muskingum River 1-4	AEP	790.0	01-Jun-15
Picway 5	AEP	95.0	01-Jun-15
Sporn	AEP	580.0	01-Jun-15
Tanners Creek 1-3	AEP	488.1	01-Jun-15
Ashtabula	ATSI	210.0	01-Jun-15
Eastlake 1-3	ATSI	327.0	01-Jun-15
Lake Shore	ATSI	190.0	01-Jun-15
Hutchings 1-3, 5-6	DAY	271.8	01-Jun-15
Bergen 3	PSEG	21.0	01-Jun-15
Burlington 8, 11	PSEG	205.0	01-Jun-15
Edison 1-3	PSEG	504.0	01-Jun-15
Essex 10-11	PSEG	352.0	01-Jun-15
Mercer 3	PSEG	115.0	01-Jun-15
National Park 1	PSEG	21.0	01-Jun-15
Sewaren 1-4, 6	PSEG	558.0	01-Jun-15
BL England Diesels	AECO	8.0	01-Oct-15
Chesapeake 3-4	Dominion	354.0	31-Dec-15
Oyster Creek	JCPL	614.5	31-Dec-19
Total		13,071.7	

Table 11-13 HEDD Units in PJM as of January 1, 2013[20]

Unit	Zone	MW
Carlls Corner 1-2	AECO	72.6
Cedar Station 1-3	AECO	66.0
Cumberland 1	AECO	92.0
Mickleton 1	AECO	72.0
Middle Street 1-3	AECO	75.3
Missouri Ave. B,C,D	AECO	60.0
Sherman Ave.	AECO	92.0
Vineland West CT	AECO	26.0
Forked River 1-2	JCPL	65.0
Gilbert 4-7, 9, C1-C4	JCPL	446.0
Glen Gardner A1-A4, B1-B4	JCPL	160.0
Lakewood 1-2	JCPL	316.1
Parlin NUG	JCPL	114.0
Sayreville C1-C4	JCPL	224.0
South River NUG	JCPL	299.0
Werner C1-C4	JCPL	212.0
Bayonne	PSEG	118.5
Bergen 3	PSEG	21.0
Burlington 111-114, 121-124, 91-94, 8	PSEG	557.0
Camden	PSEG	145.0
Eagle Point 1-2	PSEG	127.1
Edison 11-14, 21-24, 31-34	PSEG	504.0
Elmwood	PSEG	67.0
Essex 101-104, 111-114, 121,124	PSEG	536.0
Kearny 9-11, 121-124	PSEG	446.0
Linden 1-2	PSEG	1,230.0
Mercer 3	PSEG	115.0
National Park	PSEG	21.0
Newark Bay	PSEG	120.2
Pedricktown	PSEG	120.3
Salem 3	PSEG	38.4
Sewaren 6	PSEG	105.0
Total		6,663.5

Actual Generation Deactivations in 2012

Table 11-14 shows unit deactivations for 2012 through January 1, 2013.[21] A total of 7,130.9 MW retired from January 1, 2012, through January 1, 2013, including 2,320 MW from FirstEnergy Corp, or 32.5 percent of these retirements. The retirements included 5,813.9 MW of coal steam generation, 788.0 MW of light oil generation, 250.0 MW of natural gas generation, 166.0 MW of heavy oil generation, 16.0 MW of wood waste generation and 3.0 MW of diesel generation. Of these retirements, 1,458.0 MW, or 20.4 percent, were in the ATSI zone

20 See "Current New Jersey Turbines that are HEDD Units," <http://www.state.nj.us/dep/workgroups/docs/apcrule_20110909turbinelist.pdf> (Accessed January 1, 2013)

21 *"PJM Generator Deactivations,"* PJM.com <http://pjm.com/planning/generation-retirements/gr-summaries.aspx> (January 24, 2013).

Table 11-14 Unit deactivations: January 2012 through January 1, 2013

Company	Unit Name	ICAP	Primary Fuel	Zone Name	Age (Years)	Retirement Date
American Electric Power Company, Inc.	Sporn 5	440.0	Coal	AEP	51	Feb 13, 2012
Edison International	State Line 3	197.0	Coal	ComEd	56	Mar 25, 2012
Edison International	State Line 4	318.0	Coal	ComEd	51	Mar 25, 2012
GDF Suez	Viking Energy NUG	16.0	Wood Waste	PPL	24	Mar 31, 2012
Duke Energy Corporation	Walter C Beckjord 1	94.0	Coal	DEOK	59	May 01, 2012
Pepco Holdings, Inc.	Buzzard Point East Banks 1, 2, 4-8	112.0	Light Oil	Pepco	44	May 31, 2012
Pepco Holdings, Inc.	Buzzard Point West Banks 1-9	128.0	Light Oil	Pepco	44	May 31, 2012
Exelon Corporation	Eddystone 2	309.0	Coal	PECO	51	May 31, 2012
GenOn Energy, Inc.	Niles 2	108.0	Coal	ATSI	58	Jun 01, 2012
GenOn Energy, Inc.	Elrama 1	93.0	Coal	DLCO	60	Jun 01, 2012
GenOn Energy, Inc.	Elrama 2	93.0	Coal	DLCO	59	Jun 01, 2012
GenOn Energy, Inc.	Elrama 3	103.0	Coal	DLCO	57	Jun 01, 2012
Public Service Enterprise Group Incorporated	Kearny 10	122.0	Natural Gas	PSEG	42	Jun 01, 2012
Public Service Enterprise Group Incorporated	Kearny 11	128.0	Natural Gas	PSEG	42	Jun 01, 2012
Pepco Holdings, Inc.	Benning 15	275.0	Light Oil	Pepco	44	Jul 17, 2012
Pepco Holdings, Inc.	Benning 16	273.0	Light Oil	Pepco	40	Jul 17, 2012
Edison International	Crawford 8	319.0	Coal	ComEd	51	Aug 24, 2012
Edison International	Crawford 7	213.0	Coal	ComEd	54	Aug 28, 2012
Edison International	Fisk Street 19	326.0	Coal	ComEd	53	Aug 30, 2012
FirstEnergy Corp	Albright 1	73.0	Coal	APS	59	Sep 01, 2012
FirstEnergy Corp	Albright 2	73.0	Coal	APS	59	Sep 01, 2012
FirstEnergy Corp	Albright 3	137.0	Coal	APS	57	Sep 01, 2012
FirstEnergy Corp	Armstrong 1	172.0	Coal	APS	54	Sep 01, 2012
FirstEnergy Corp	Armstrong 2	171.0	Coal	APS	55	Sep 01, 2012
FirstEnergy Corp	R Paul Smith 3	28.0	Coal	APS	64	Sep 01, 2012
FirstEnergy Corp	R Paul Smith 4	87.0	Coal	APS	53	Sep 01, 2012
FirstEnergy Corp	Rivesville 5	35.0	Coal	APS	69	Sep 01, 2012
FirstEnergy Corp	Rivesville 6	86.0	Coal	APS	61	Sep 01, 2012
FirstEnergy Corp	Willow Island 1	53.0	Coal	APS	63	Sep 01, 2012
FirstEnergy Corp	Willow Island 2	164.0	Coal	APS	51	Sep 01, 2012
FirstEnergy Corp	Bay Shore 2	120.0	Coal	ATSI	53	Sep 01, 2012
FirstEnergy Corp	Bay Shore 3	119.0	Coal	ATSI	49	Sep 01, 2012
FirstEnergy Corp	Bay Shore 4	180.0	Coal	ATSI	44	Sep 01, 2012
FirstEnergy Corp	Eastlake 4	225.0	Coal	ATSI	56	Sep 01, 2012
FirstEnergy Corp	Eastlake 5	597.0	Coal	ATSI	40	Sep 01, 2012
City of Vineland	Howard Down 10	23.0	Coal	AECO	42	Sep 01, 2012
GenOn Energy, Inc.	Niles 1	109.0	Coal	ATSI	58	Oct 01, 2012
GenOn Energy, Inc.	Elrama 4	171.0	Coal	DLCO	51	Oct 01, 2012
GenOn Energy, Inc.	Potomac River 1	88.0	Coal	Pepco	63	Oct 01, 2012
GenOn Energy, Inc.	Potomac River 2	88.0	Coal	Pepco	62	Oct 01, 2012
GenOn Energy, Inc.	Potomac River 3	102.0	Coal	Pepco	58	Oct 01, 2012
GenOn Energy, Inc.	Potomac River 4	102.0	Coal	Pepco	56	Oct 01, 2012
GenOn Energy, Inc.	Potomac River 5	102.0	Coal	Pepco	55	Oct 01, 2012
Smart Papers Holdings LLC	SMART Paper	24.9	Coal	DEOK	88	Oct 10, 2012
American Electric Power Company, Inc.	Conesville 3	165.0	Coal	AEP	50	Dec 31, 2012
Exelon Corporation	Schuylkill 1	166.0	Heavy Oil	PECO	54	Jan 01, 2013
Exelon Corporation	Schuylkill Diesel	3.0	Diesel	PECO	45	Jan 01, 2013

Updates on Key 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.

On May 17, 2012, the PJM Board of Managers approved approximately $2 billion in transmission facilities upgrades, including more than 130 separate transmission upgrades.[22] The upgrades include upgrading existing transmission lines, constructing new transmission lines, installing new transformers, installing new substations, and adding capacitors and SVCs.

Transmission projects above $5 million are shown in Table 11-15, Table 11-16 and Table 11-17 for the Eastern, Western and Southern regions of PJM.

Table 11-15 Major upgrade projects in Eastern Region

Zone	Upgrade Description	Cost (Millions)
JCPL	Construct a new Whippany to Montville 230 kV line	$37.5
PENELEC	Convert the Lewis Run Farmers Valley 115 kV line to 230 kV	$46.8
PENELEC	Construct Farmers Valley 345/230 kV and 230/115 kV substation by looping the Homer City to Stolle Road 345 kV line into Farmers Valley	$29.5
PENELEC	Relocate the Erie South 345 kV line bay	$13.0
PENELEC	Construct a 115 kV ring bus at Claysburg Substation	$5.3
Pepco	Reconductor 230 kV line 23032 and 23034 with high temperature conductor	$16.0
PPL	Install a new North Lancaster 500/230 kV substation	$42.0

Table 11-16 Major upgrade projects in Western Region

Zone	Upgrade Description	Cost (Millions)
AEP	Install a new 765/345 substation at Mountaineer and build a ¾ mile 345 kV line to Sporn	$65.0
AEP	Add four 765 kV breakers at Kammer	$30.0
AEP	Reconductor Kammer West Bellaire 345 kV	$20.0
AEP	Terminate Transformer #2 at SW Lima in a new bay position	$5.0
APS	Loop the Homer City-Handsome Lake 345 kV line into the Armstrong substation and install a 345/138 kV transformer at Armstrong	$27.8
APS	Install a new Buckhannon Weston 138 kV line	$17.5
APS	Convert Moshannon substation to a four breaker 230 kV ring	$6.5
ATSI	Build a new Toronto to Harmon 345 kV line	$218.3
ATSI	Build a new Mansfield - Northfield Area 345 kV line	$184.5
ATSI	Convert Eastlake units 1, 2, 3, 4 and 5 to synchronous condensers	$100.0
ATSI	Build new Allen Jct - Midway - Lemoyne 345kV line	$86.3
ATSI	Create a new Harmon 345/138/69 kV substation by looping in the Star South Canton 345 kV line	$46.0
ATSI	Build a new Leroy Center 345/138 kV substation by looping in the Perry Harding 345 kV line	$46.0
ATSI	Build a new West Fremont Groton Hayes 138 kV line	$45.0
ATSI	Build a new Toronto 345/138 kV substation	$41.8
ATSI	Create a new Northfield Area 345 kV switching station by looping in the Eastlake Juniper 345 kV line and the Perry - Inland 345 kV line	$37.5
ATSI	Build a new 345-138kV Substation at Niles	$32.0
ATSI	Add a new 150 MVAR SVC and 100 MVAR capacitor at New Castle	$31.7
ATSI	Create a new Five Points Area 345/138 kV substation by looping in the Lemoyne Midway 345 kV line	$30.0
ATSI	Convert Lakeshore 18 to synchronous condensers	$20.0
ATSI	Build a new substation near the ATSI-AEP border and a new 138kV line from new substation to Longview	$17.7
ATSI	Re-conductor the Galion GM Mansfield Ontario - Cairns 138 kV line	$9.8
ATSI	Build a new Harmon Brookside + Harmon - Longview 138 kV line	$9.2
ATSI	Install a 345/138 kV transformer at the Inland Q-11 station	$7.2
ATSI	Install a 2nd 345/138 kV transformer at the Allen Junction station	$7.2
ATSI	Install a 2nd 345/138 kV transformer at the Bay Shore station	$7.2
ATSI	Reconductor the ATSI portion of South Canton Harmon 345 kV line	$6.0
DLCO	Install a third 345/138 kV transformer at Collier	$8.0

22 *"TEAC Recommendations to the PJM Board, May 2012,"* PJM.com <http://pjm.com/~/media/committees-groups/committees/teac/20120614/20120614-pjm-board-whitepaper.ashx> (Accessed January 30, 2013).

Table 11-17 Major upgrade projects in Southern Region

Zone	Upgrade Description	Cost (Millions)
Dominion	Rebuild Lexington to Dooms 500 kV line	$120.0
Dominion	Build a 500 MVAR SVC at Landstown 230 kV	$60.0
Dominion	Build new Surry to Skiffes Creek 500 kV line	$58.3
Dominion	Build new Skiffes Creek Whealton 230 kV line	$46.4
Dominion	Expand Yadkin 500/230 kV and 230/115 kV substation and Chesapeake 230/115 kV substation	$45.0
Dominion	Build new Skiffes Creek 500/230 substation	$42.4
Dominion	Build a new Suffolk to Yadkin 230 kV line	$40.0
Dominion	Add a third 500/230 kV transformer at Yadkin	$16.0
Dominion	Install a third 500/230 kV transformer at Clover	$16.0
Dominion	Install a second Valley 500/230 kV transformer	$16.0
Dominion	Upgrade Bremo Midlothian 230 kV line	$10.0
Dominion	Add six 500 kV breakers at Yadkin	$8.0

In August, 2012, the PJM Board of Managers cancelled the Potomac-Appalachian Transmission Highline (PATH) and Mid-Atlantic Power Pathway (MAPP) projects based on recommendations from Transmission Expansion Advisory Committee (TEAC) that were based in part on reductions in load growth.[23]

On October 1, 2012, the Susquehanna – Roseland project received final approval from the National Park Service (NPS) for the project to be constructed on the route selected by PSEG and PPL.[24]

Transmission Planning Rules

In 2012, the Commission approved PJM proposed revisions to its planning process that removed some of its bright line aspects.[25] The Commission found that "the proposed revisions strike an appropriate balance between the need for PJM to maintain some flexibility given the scenario-based nature of the analysis in PJM's revised RTEP process and the need for sufficient detail in the tariff to allow stakeholders to participate in the planning process."[26] The Commission also found that the revisions "define a reasonable framework for its revised RTEP process while expanding the opportunities for stakeholder participation throughout its transmission planning process."[27] The Commission rejected arguments that rules lacked specific metrics and criteria for PJM to employ when evaluating the results of sensitivity studies and scenario analyses.[28] The Commission indicated that it may reconsider some of these changes in its review of PJM's Order No. 1000 compliance filing, now pending in FERC Docket No. ER13-198.

Competitive Grid Development

In Order No. 1000, the FERC requires regional transmission planning processes to modify the criteria for an entity to "propose a transmission project for selection in the regional transmission plan for purposes of cost allocation, whether that entity is an incumbent transmission provider or a nonincumbent transmission developer."[29,30] Such criteria "must not be unduly discriminatory or preferential."[31]

Order No. 1000 requires, among other things, that each public utility transmission provider (including PJM) remove from its FERC approved tariff and agreements, as necessary and subject to certain limitations, a federal right of first refusal (ROFR) for certain new transmission projects.[32] ROFR would continue to apply to transmission projects not included in a regional transmission plan for purposes of cost allocation, and ROFR would continue apply to upgrades to transmission facilities.[33]

Order No. 1000 allows, but does not require, competitive bidding to solicit transmission projects or developers.[34] The rule does not override or otherwise affect state or local laws concerning construction of transmission facilities, such as siting or permitting.[35]

On October 25, 2012, PJM submitted a filing in compliance with Order No. 1000.[36] PJM adopted a sponsorship model and made some organizational changes to the process, including defining three categories of projects, Long-lead projects, Short-term Projects and Immediate-need Reliability Projects, and applying different procedural rules to each.[37]

The MMU filed a protest complaining that PJM's proposal continued to lack definition to key terms that

23 See PJM.com. "Potomac – Appalachian Transmission Highline (PATH) <http://www.pjm.com/planning/rtep-upgrades-status/backbone-status/path.aspx>(Accessed November 1, 2012).
24 See PSEG.com. "Susquehanna-Roseland line receives final federal approval) <http://www.pseg.com/info/media/newsreleases/2012/2012-10-02.jsp> (Accessed November 1, 2012).
25 139 FERC ¶ 61,080 (April 30, 2012), order accepting compliance filing, 141 FERC ¶ 61,160 (November 29, 2012).
26 141 FERC ¶ 61,160 at P 21.
27 *Id.* at P 21.
28 *Id.* at P 22.
29 Order No. 1000, FERC Stats. & Regs. ¶31,323 (2011).
30 Order No. 1000 at PP 323–327.
31 *Id.* at PP 323–324.
32 *Id.* at PP 313–322.
33 *Id.* at PP 318–319.
34 *Id.* at P 321 & n.302.
35 *Id.* at PP 337, 339.
36 PJM Compliance in RM10-23, FERC Docket No. ER13-198 ("Order 1000 Compliance Filing").
37 Order 1000 Compliance Filing at 13–14.

affect the evaluation of projects and did not allow for meaningful competition on project costs.[38] The MMU is concerned that the process continues to contain shortcomings evident in RTEP consideration of certain projects proposed by Primary Power, which lead to litigation. That litigation was resolved in an order on complaint that found that PJM has followed the current rules when awarding to incumbents certain projects contested by Primary Power.[39] The MMU filed comments in that proceeding, observing, "There does not appear to have been a process that would have permitted direct competition between Primary Power and the Incumbents."[40] The MMU also pointed out that Primary Power's complaint demonstrated that the concepts of sponsorship, upgrades and new versus revised projects needed clarification.[41] The Commission explained that it "stated in Order No. 1000 that the public utility transmission providers in a region may, but are not required to, use competitive solicitation to solicit project or project developers to meet regional needs."[42]

The MMU also recommended to the Commission that PJM include in its Order No. 1000 compliance filing provisions that would allow competition to finance projects, without regard to who proposes them, or who builds them or owns them.[43]

38 Comments of the Independent Market Monitor for PJM, Docket No. ER13-198 (December 10, 2012) ("December 10th IMM Comments").
39 140 FERC ¶ 61,054 at P 69 (July 19, 2012).
40 Motion for Leave to Answer and Answer of the Independent Market Monitor for PJM, Docket No. EL12-69-000 (June 22, 2012).
41 *Id.* at 3–4.
42 140 FERC ¶ 61,054 at P 83.
43 *See* December 10th IMM Comments at 4–7.