Generation and Transmission Planning

Highlights

- At June 30, 2012, 79,186 MW of capacity were in generation request queues for construction through 2018, compared to an average installed capacity of 183,000 MW in 2012 including the January 1, 2012, DEOK integration. Wind projects account for approximately 27,710 MW, 35.0 percent of the capacity in the queues, and combined-cycle projects account for 38,587 MW, 48.7 percent of the capacity in the queues.
- A total of 2,261 MW of generation capacity retired in January through June 2012, and it is expected that a total of 19,008.9 MW will have retired from 2011 through 2019, with most of this capacity retiring by the end of 2015. Units planning to retire in 2012 make up 4,168.9 MW, or 27 percent of all planned retirements.
- The recent decision on Primary Power, LLC's complaint indicates the need for more definition of the process for selecting projects and permitting incumbents and nonincumbents to compete.[1] The MMU recommends that PJM include in its Order No. 1000 compliance filing, due October 11, 2012, rules that clarify how nonincumbents can compete to provide transmission projects. These rules should allow nonincumbents to compete on a physical basis by having the opportunity to compete to provide transmission projects and to compete on a financial basis by having the opportunity to compete directly to finance such projects.

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 June 30, 2012, 79,186 MW of capacity were in generation request queues for construction through 2018, compared to an average installed capacity of 183,000 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).[2] Overall, 1,392 MW of nameplate capacity were added in PJM in January through June 2012 (excluding the integration of the DEOK zone).

1 140 FERC ¶ 61,054.

Table 11-1 Year-to-year capacity additions from PJM generation queue: Calendar years 2000 through June 30, 2012[3]

	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
January-June 2012	1,392

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 X was active through January 31, 2012.

Capacity in generation request queues for the seven year period beginning in 2012 and ending in 2018 decreased by 11,539 MW from 90,725 MW in 2011 to 79,186 MW in 2012, or 12.7 percent (Table 11-2).[4] Queued capacity

2 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.
3 The capacity described in this table refers to all installed capacity in PJM, regardless of whether the capacity entered the RPM auction.
4 See the *2011 State of the Market Report for PJM*: Volume II, Section 11), pp. 286-288, for the queues in 2011.

scheduled for service in 2012 decreased from 27,184 MW to 20,203 MW, or 25.7 percent. Queued capacity scheduled for service in 2013 decreased from 13,051 MW to 9,364 MW, or 28.3 percent. The 79,186 MW includes generation with scheduled in-service dates in 2011 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): June 30, 2012 vs. December 31, 2011 (See 2011 SOM, Table 11-3)

	MW in the Queue 2011	MW in the Queue 2012	Year-to-Year Change (MW)	Year-to-Year Change
2012	27,184	20,203	(6,980)	(25.7%)
2013	13,051	9,364	(3,687)	(28.3%)
2014	17,036	11,025	(6,012)	(35.3%)
2015	19,251	23,563	4,312	22.4%
2016	9,288	7,441	(1,848)	(19.9%)
2017	1,720	5,996	4,276	248.6%
2018	3,194	1,594	(1,600)	(50.1%)
Total	90,725	79,186	(11,539)	(12.7%)

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.[5]

5 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.

Table 11-3 Capacity in PJM queues (MW): At June 30, 2012[6,7]

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	148	150	2,345	2,643
L Expired 31-Jan-04	20	257	0	4,014	4,290
M Expired 31-Jul-04	0	505	422	3,556	4,482
N Expired 31-Jan-05	177	2,279	38	7,913	10,407
O Expired 31-Jul-05	446	1,491	860	4,795	7,592
P Expired 31-Jan-06	413	2,915	455	4,908	8,690
Q Expired 31-Jul-06	182	2,038	2,914	9,400	14,534
R Expired 31-Jan-07	2,666	1,371	198	18,694	22,930
S Expired 31-Jul-07	2,174	3,463	403	11,400	17,440
T Expired 31-Jan-08	8,427	1,197	216	17,706	27,546
U Expired 31-Jan-09	5,168	256	541	27,052	33,017
V Expired 31-Jan-10	7,686	196	1,617	7,564	17,064
W Expired 31-Jan-11	9,358	174	1,017	13,850	24,398
X Expired 31-Jan-12	23,137	46	273	7,668	31,124
Y Expires 31-Jan-13	9,702	0	0	31	9,733
Total	69,557	33,275	9,629	225,371	337,831

Data presented in Table 11-4 show that through the first six months of 2012, 38.3 percent of total in-service capacity from all the queues was from Queues A and B and an additional 6.5 percent was from Queues C, D and E.[8] As of June 30, 2012, 31.8 percent of the capacity in Queues A and B has been placed in service, and 9.8 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 809 days between entering a queue and the in-service date. The data also show that for withdrawn projects, there is an average time

6 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.
7 Projects listed as partially in-service are counted as in-service for the purposes of this analysis.
8 The data for Queue Y include projects through June 30, 2012.

of 503 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 June 30, 2012 (See 2011 SOM, Table 11-5)

Status	Average (Days)	Standard Deviation	Minimum	Maximum
Active	866	604	0	3,060
In-Service	809	710	0	3,964
Suspended	2,046	964	704	4,162
Under Construction	1,290	809	0	5,083
Withdrawn	503	510	0	3,186

Table 11-5 shows queued capacity that was planned to be in service by July 1, 2012. This indicates there is a substantial amount of queued capacity that is not yet under construction that should already be in service based on the original queue date.

Table 11-5 Active capacity queued to be in service prior to July 1, 2012 (New table)

	MW
2007	295.0
2008	962.0
2009	406.9
2010	3,019.5
2011	5,398.2
2012	2,099.6
Total	12,181.1

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 June 30, 2012, 79,186 MW of capacity were in generation request queues for construction through 2018, compared to an average installed capacity of 183,000 MW in 2012 including the January 1, 2012, DEOK integration. Wind projects account for approximately 27,710 MW, 35.0 percent of the capacity in the queues, and combined-cycle projects account for 38,587 MW, 48.7 percent of the capacity in the queues. There has been a substantial increase in combined cycle units added to the queues. On June 30, 2012, there were 38,587 MW of capacity from combined cycle units in the queue, compared to 34,788 MW in 2011, an increase of 10.9 percent.

Table 11-6 shows the projects under construction or active as of June 30, 2012, by unit type and control zone. Most of the steam projects (92.1 percent of the MW) and most of the wind projects (93.6 percent of the MW) are outside the Eastern MAAC (EMAAC)[9] and Southwestern MAAC (SWMAAC)[10] locational deliverability areas (LDAs).[11] Of the total capacity additions, only 16,858 MW, or 21.3 percent, are projected to be in EMAAC, while 6,669 MW or 8.4 percent are projected to be constructed in SWMAAC. Of total capacity additions, 33,383 MW, or 42.7 percent of capacity, is being added inside MAAC zones. Overall, 70.2 percent of capacity is being added outside EMAAC and SWMAAC, and 57.8 percent of capacity is being added outside MAAC zones.

Wind projects account for approximately 27,710 MW of capacity or 35.0 percent of the capacity in the queues and combined-cycle projects account for 38,587 MW of capacity or 48.7 percent of the capacity in the queues.[12] Wind projects account for 3,723 MW of capacity in MAAC LDAs, or 11.2 percent. While there are no wind projects in the SWMAAC LDA, in the EMAAC LDA wind projects account for 1,769 MW of capacity, or 10.4 percent.

9 EMAAC consists of the AECO, DPL, JCPL, PECO and PSEG Control Zones.
10 SWMAAC consists of the BGE and Pepco Control Zones.
11 See the *2011 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography" for a map of PJM LDAs.
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 27,710 MW of wind resources and 3,017 MW of solar resources, the 79,186 MW currently active in the queue would be reduced to 53,207 MW.

Table 11-6 Capacity additions in active or under-construction queues by control zone (MW): At June 30, 2012 (See 2011 SOM, Table 11-6)

	CC	CT	Diesel	Hydro	Nuclear	Solar	Steam	Storage	Wind	Total
AECO	2,797	63	11	0	0	541	138	0	1,419	4,969
AEP	2,950	0	70	70	0	132	362	8	10,998	14,590
AP	930	0	13	75	0	232	869	0	910	3,029
ATSI	3,816	72	10	0	0	94	135	0	849	4,976
BGE	678	256	1	0	1,640	2	0	0	0	2,577
ComEd	1,080	444	103	23	607	95	640	22	9,618	12,631
DAY	0	0	2	112	0	23	12	0	895	1,044
DEOK	20	135	0	0	0	0	0	0	0	155
DLCO	40	0	0	5	91	0	0	0	0	136
Dominion	5,774	595	4	0	1,594	140	397	20	718	9,242
DPL	2,078	1	4	0	0	297	22	27	330	2,760
JCPL	2,770	47	30	0	0	960	0	0	0	3,806
Met-Ed	1,910	0	18	0	58	83	0	0	0	2,069
PECO	698	7	8	0	490	10	0	5	0	1,217
PENELEC	905	20	31	0	0	32	146	0	1,469	2,603
Pepco	4,057	0	25	0	0	10	0	0	0	4,092
PPL	4,476	11	4	3	100	86	0	20	485	5,185
PSEG	3,608	77	9	0	50	280	60	2	20	4,106
Total	38,587	1,728	342	288	4,630	3,017	2,781	104	27,710	79,186

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 11-7 Capacity additions in active or under-construction queues by LDA (MW): At June 30, 2012[13]

	CC	CT	Diesel	Hydro	Nuclear	Solar	Steam	Storage	Wind	Total
EMAAC	11,950	195	62	0	540	2,088	220	34	1,769	16,858
SWMAAC	4,735	256	26	0	1,640	12	0	0	0	6,669
WMAAC	7,291	31	53	3	158	201	146	20	1,954	9,856
Non-MAAC	14,610	1,246	202	285	2,292	716	2,415	50	23,987	45,802
Total	38,587	1,728	342	288	4,630	3,017	2,781	104	27,710	79,186

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.

13 WMAAC consists of the Met-Ed, PENELEC, and PPL 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.

Table 11-8 Existing PJM capacity: At June 30, 2012[14]

	CC	CT	Diesel	Hydroelectric	Nuclear	Solar	Steam	Storage	Wind	Total
AECO	164	701	21	0	0	40	1,110	0	8	2,043
AEP	4,900	3,682	59	1,072	2,071	0	21,677	0	1,553	35,014
AP	1,129	1,215	34	80	0	0	8,451	27	799	11,735
ATSI	685	1,661	71	0	2,134	0	7,890	0	0	12,441
BGE	0	835	10	0	1,714	0	3,007	0	0	5,566
ComEd	1,763	7,257	86	0	10,438	0	6,275	0	2,254	28,073
DAY	0	1,369	48	0	0	1	4,368	0	0	5,785
DEOK	0	842	0	0	0	0	2,257	0	0	3,099
DLCO	244	15	0	6	1,777	0	955	0	0	2,997
Dominion	4,030	3,762	174	3,589	3,581	3	8,285	0	0	23,422
DPL	1,125	1,822	96	0	0	0	1,800	3	0	4,847
External	974	990	0	0	439	0	6,367	0	185	8,955
JCPL	1,693	1,225	33	400	615	22	15	0	0	4,003
Met-Ed	2,051	408	41	20	805	0	844	0	0	4,168
PECO	3,209	836	6	1,642	4,541	3	1,145	1	0	11,383
PENELEC	0	344	46	513	0	0	6,831	0	680	8,413
Pepco	230	1,092	12	0	0	0	4,679	0	0	6,013
PPL	1,793	618	49	582	2,520	0	5,537	0	220	11,317
PSEG	3,091	2,861	12	5	3,493	97	2,017	0	0	11,576
Total	27,080	31,533	797	7,908	34,127	166	93,509	31	5,699	200,848

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

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

Table 11-9 PJM capacity (MW) by age: at June 30, 2012 (See 2011 SOM Table 11-9)

Age (years)	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Solar	Steam	Storage	Wind	Total
Less than 11	18,982	9,255	416	11	0	166	2,399	31	5,664	36,925
11 to 20	6,062	13,064	132	48	0	0	3,261	0	34	22,601
21 to 30	1,594	1,686	56	3,448	15,409	0	8,417	0	0	30,610
31 to 40	244	3,106	43	105	16,353	0	29,664	0	0	49,515
41 to 50	198	4,421	135	2,849	2,365	0	30,544	0	0	40,512
51 to 60	0	0	15	379	0	0	16,145	0	0	16,539
61 to 70	0	0	0	0	0	0	2,904	0	0	2,904
71 to 80	0	0	0	280	0	0	95	0	0	375
81 to 90	0	0	0	549	0	0	79	0	0	628
91 to 100	0	0	0	155	0	0	0	0	0	155
101 and over	0	0	0	84	0	0	0	0	0	84
Total	27,080	31,533	797	7,908	34,127	166	93,509	31	5,699	200,848

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.

Without the planned coal-fired capability in EMAAC, new gas-fired capability would represent 73.0 percent of all new capability in EMAAC and 80.4 percent when the derating of wind capacity is reflected.

There is a planned addition of 1,640 MW of nuclear capacity in SWMAAC. Without the planned nuclear capability in SWMAAC, new gas-fired capability would represent 99.2 percent of all new capability in the SWMAAC. In 2018, this would mean that CC and CT generators would comprise 56.9 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.[15] In these zones, 88.8 percent of all generation 40 years or older is steam (primarily coal). With the retirement of these units in 2018, wind farms would comprise 20.6 percent of total capacity in Non-MAAC zones, if all queued capacity is built.

15 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[16]

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	27.4%	11,950	21,034	48.9%
	Combustion Turbine	2,229	26.9%	7,445	22.0%	195	5,412	12.6%
	Diesel	51	0.6%	168	0.5%	62	179	0.4%
	Hydroelectric	2,042	24.6%	2,047	6.0%	0	620	1.4%
	Nuclear	615	7.4%	8,648	25.5%	540	8,574	19.9%
	Solar	0	0.0%	162	0.5%	2,088	2,250	5.2%
	Steam	3,158	38.1%	6,087	18.0%	220	3,149	7.3%
	Storage	0	0.0%	4	0.0%	34	38	0.1%
	Wind	0	0.0%	8	0.0%	1,769	1,777	4.1%
	EMAAC Total	8,292	100.0%	33,851	100.0%	16,858	43,032	100.0%
SWMAAC	Combined Cycle	0	0.0%	230	2.0%	4,735	4,965	37.5%
	Combustion Turbine	542	10.8%	1,927	16.6%	256	1,640	12.4%
	Diesel	0	0.0%	22	0.2%	26	48	0.4%
	Nuclear	0	0.0%	1,714	14.8%	1,640	3,354	25.3%
	Solar	0	0.0%	0	0.0%	12	12	0.1%
	Steam	4,459	89.2%	7,686	66.4%	0	3,227	24.4%
	SWMAAC Total	5,001	100.0%	11,578	100.0%	6,669	13,246	100.0%
WMAAC	Combined Cycle	0	0.0%	3,843	16.1%	7,291	11,134	77.8%
	Combustion Turbine	559	6.1%	1,369	5.7%	31	842	5.9%
	Diesel	46	0.5%	136	0.6%	53	142	1.0%
	Hydroelectric	887	9.7%	1,114	4.7%	3	1,117	7.8%
	Nuclear	0	0.0%	3,325	13.9%	158	3,483	24.3%
	Solar	0	0.0%	0	0.0%	201	201	1.4%
	Steam	7,702	83.8%	13,211	55.3%	146	5,656	39.5%
	Storage	0	0.0%	0	0.0%	20	20	0.1%
	Wind	0	0.0%	900	3.8%	1,954	2,854	19.9%
	WMAAC Total	9,194	100.0%	23,898	100.0%	9,856	14,314	100.0%
Non-MAAC	Combined Cycle	0	0.0%	13,724	10.4%	14,610	28,335	20.2%
	Combustion Turbine	1,092	2.8%	20,792	15.8%	1,246	20,946	15.0%
	Diesel	53	0.1%	471	0.4%	202	620	0.4%
	Hydroelectric	1,433	3.7%	4,748	3.6%	285	5,032	3.6%
	Nuclear	1,751	4.5%	20,440	15.5%	2,292	20,981	15.0%
	Solar	0	0.0%	4	0.0%	716	719	0.5%
	Steam	34,449	88.8%	66,524	50.6%	2,415	34,490	24.6%
	Storage	0	0.0%	27	0.0%	50	77	0.1%
	Wind	0	0.0%	4,791	3.6%	23,987	28,778	20.6%
	Non-MAAC Total	38,777	100.0%	131,521	100.0%	45,802	139,979	100.0%
All Areas	Total	61,263		200,848		79,186	210,571	

16 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, 15,425.5 MW are planning to deactivate by the end of calendar year 2019. Units planning to retire in 2012 make up 4,168.9 MW, or 27 percent of all planned retirements. Of planned deactivations in 2012, approximately 1,350 MW, or 32.4 percent are located in the ATSI zone. Overall, 3,951.1 MW, or 25.6 percent of all retirements, are expected in the AEP zone. Figure 11-1 shows plant retirements throughout the PJM footprint, with retirements in nearly every PJM state. A total of 1,322.3 MW retired in 2011, and a total of 2,261 MW retired between January and June 2012. It is expected that a total of 19,008.8 MW will have retired by 2019, with most of this capacity retiring by the end of 2015.

Table 11-11 Summary of PJM unit retirements (MW): Calendar year 2011 through 2019[17]

	MW
Retirements 2011	1,322.3
Retirements 2012	2,261.0
Planned Retirements 2012	4,168.9
Planned Retirements Post-2012	11,256.6
Total	19,008.8

Table 11-12 Planned deactivations of PJM units in Calendar year 2012 as of June 30, 2012[18] (See 2011 SOM, Table 11-12)

Unit	Zone	MW	Projected Deactivation Date
Benning 15-16	Pepco	548.0	01-Jul-12
SMART Paper	DEOK	24.9	10-Aug-12
Vineland 10	AECO	23.0	01-Sep-12
Albright	APS	283.0	01-Sep-12
Armstrong 1-2	APS	343.0	01-Sep-12
R Paul Smith 3-4	APS	115.0	01-Sep-12
Rivesville 5-6	APS	121.0	01-Sep-12
Willow Island 1-2	APS	217.0	01-Sep-12
Bay Shore 2-4	ATSI	419.0	01-Sep-12
Eastlake 4-5	ATSI	822.0	01-Sep-12
Niles 1	ATSI	109.0	01-Oct-12
Elrama 4	DLCO	171.0	01-Oct-12
Potomac River 1-5	Pepco	482.0	01-Oct-12
Fisk 19	ComEd	326.0	31-Dec-12
Conesville 3	AEP	165.0	31-Dec-12
Total		4,168.9	

17 These totals include the retirements of Fisk 19 and Crawford 7&8.

18 See "Pending Deactivation Requests," <http://pjm.com/planning/generation-retirements/~/media/planning/gen-retire/pending-deactivation-requests.ashx> (Accessed July 15, 2012).

Figure 11-1 Unit retirements in PJM Calendar year 2011 through 2019 (See 2011 SOM, Figure 11-1)

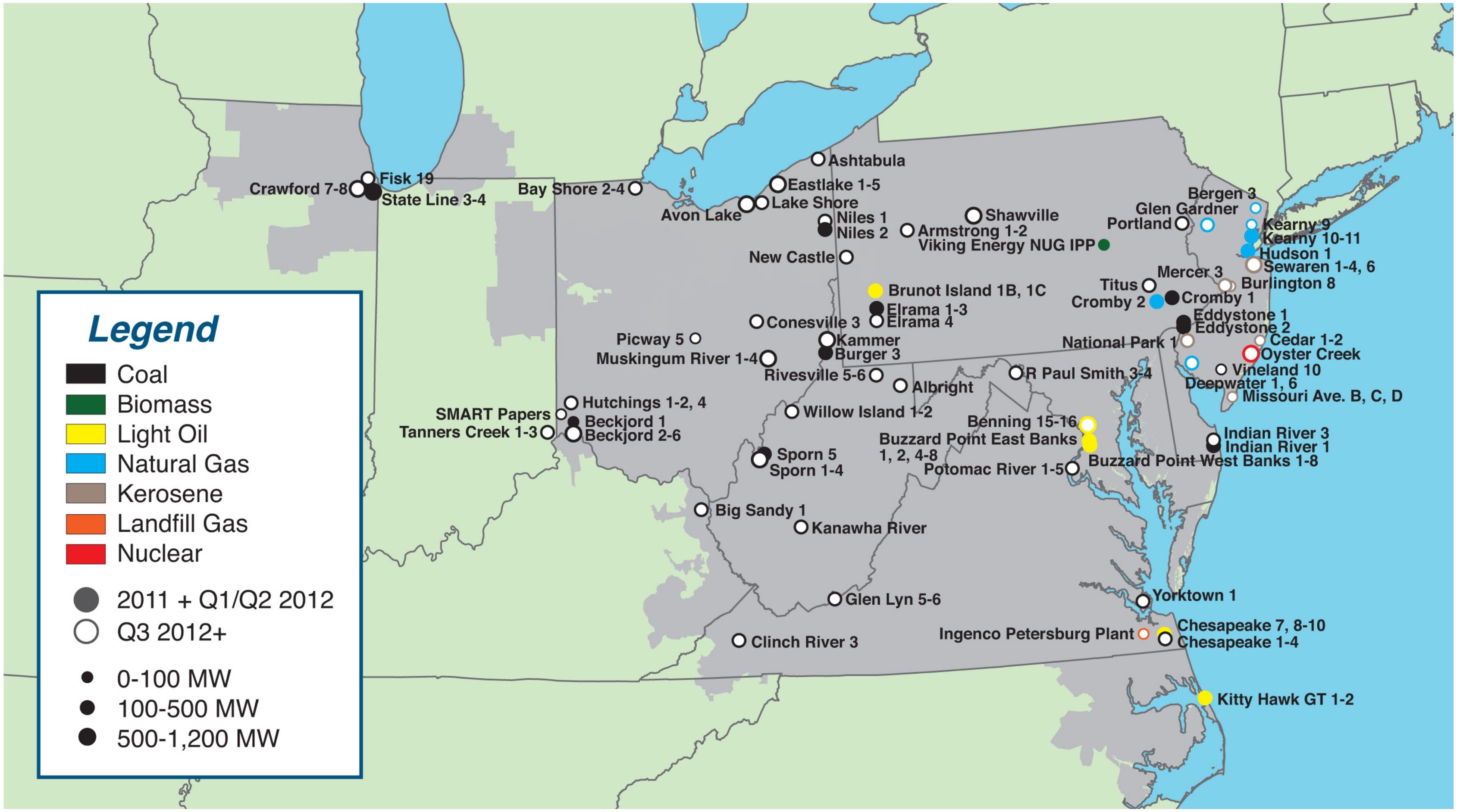

Table 11-13 Planned deactivations of PJM units after calendar year 2012, as of June 30, 2012 (See 2011 SOM, Table 11-13)

Unit	Zone	MW	Projected Deactivation Date
Ingenco Petersburg Plant	Dominion	2.9	31-May-13
Hutchings 4	DAY	61.9	01-Jun-13
Kearny 9	PSEG	21.0	01-Jun-13
Indian River 3	DPL	169.7	31-Dec-13
Crawford 7-8	ComEd	532.0	31-Dec-14
Chesapeake 1-2	Dominion	222.0	31-Dec-14
Yorktown 1	Dominion	159.0	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
Glen Gardner	JCPL	160.0	01-May-15
Cedar 1-2	AECO	67.7	31-May-15
Deepwater 1, 6	AECO	158.0	31-May-15
Missouri Ave B, C, D	AECO	60.0	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 1-2	DAY	97.3	01-Jun-15
Bergen 3	PSEG	21.0	01-Jun-15
Burlington 8	PSEG	21.0	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
Chesapeake 3-4	Dominion	354.0	31-Dec-15
Oyster Creek	JCPL	614.5	31-Dec-19
Total		11,256.6	

Table 11-14 HEDD Units in PJM as of June 30, 2012[19]

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

19 See "Current New Jersey Turbines that are HEDD Units," <http://www.state.nj.us/dep/workgroups/docs/apcrule_20110909turbinelist.pdf> (Accessed July 1, 2012)

Actual Generation Deactivations in 2012

Table 11-15 shows unit deactivations for 2012.[20] A total of 2,261 MW retired in January through June 2012, including 440.0 MW from American Electric Power Company, Inc., 515.0 MW from Edison International, 16.0 MW from GDF Suez, 94.0 MW from Duke Energy Corporation, 240.0 MW from Pepco Holdings, Inc, 309.0 MW from Exelon Corporation, 397.0 MW from GenOn Energy, Inc., and 250.0 MW from Public Service Enterprise Group Incorporated. The retirements were 1,755.0 MW of coal steam generation, 16.0 MW of wood waste generation, 240.0 MW of light oil generation, and 250.0 MW of natural gas generation. Of these retirements, 440.0 MW were in the AEP zone, 515.0 MW were in the ComEd zone, 16.0 MW in the PPL zone, 94.0 MW in the DEOK zone, 240.0 MW in the Pepco zone, 309.0 MW in the PECO zone, 108.0 MW in the ATSI zone, 289.0 MW in the DLCO zone, and 250.0 MW in the PSEG zone.

Table 11-15 Unit deactivations: January through June 2012 (See 2011 SOM, Table 11-15)

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

Transmission Planning

On May 17, 2012, the PJM Board of Managers approved approximately $2 billion in transmission facilities upgrades, including more than 130 separate transmission upgrades. The upgrades are needed to maintain system reliability in response to anticipated retirements of generating units.[21] The upgrades include upgrading existing transmission lines to higher MW capacity, constructing new transmission lines, installing new transformers, installing new substation, and adding capacitors and SVCs. Transmission projects above $5 million are shown in Table 11-16, Table 11-17 and Table 11-18 for the Eastern, Western and Southern regions of PJM.[22]

20 *"PJM Generator Deactivations,"* PJM.com <http://pjm.com/planning/generation-retirements/gr-summaries.aspx> (July 10, 2012).

21 *"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 July 16, 2012).

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 July 16, 2012).

Table 11-16 Major upgrade projects in Eastern Region (New Table)

Zone	Upgrade Description	Cost (Millions)
Pepco	Reconductor 230 kV line 23032 and 23034 with high temperature conductor	$16.0
PENELEC	Construct a 115 kV ring bus at Claysburg Substation	$5.3
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	Convert the Lewis Run Farmers Valley 115 kV line to 230 kV	$46.8
PPL	Install a new North Lancaster 500/230 kV substation	$42.0
JCPL	Construct a new Whippany to Montville 230 kV line	$37.5

Table 11-17 Major upgrade projects in Western Region (New Table)

Zone	Upgrade Description	Cost (Millions)
AEP	Reconductor Kammer West Bellaire 345 kV	$20.0
AEP	Install a new 765/345 substation at Mountaineer and build a ¾ mile 345 kV line to Sporn	$65.0
AEP	Terminate Transformer #2 at SW Lima in a new bay position	$5.0
AEP	Add four 765 kV breakers at Kammer	$30.0
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	Install a 345/138 kV transformer at the Inland Q-11 station	$7.2
ATSI	Convert Eastlake units 1, 2, 3, 4 and 5 to synchronous condensers	$100.0
ATSI	Convert Lakeshore 18 to synchronous condensers	$20.0
ATSI	Re-conductor the Galion GM Mansfield Ontario - Cairns 138 kV line	$9.8
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	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 Mansfield - Northfield Area 345 kV line	$184.5
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 Harmon Brookside + Harmon - Longview 138 kV line	$9.2
ATSI	Create a new Five Points Area 345/138 kV substation by looping in the Lemoyne Midway 345 kV line	$30.0
ATSI	Build a new 345-138kV Substation at Niles	$32.0
ATSI	Build a new substation near the ATSI-AEP border and a new 138kV line from new substation to Longview	$17.7
ATSI	Build new Allen Jct - Midway - Lemoyne 345kV line	$86.3
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 Toronto to Harmon 345 kV line	$218.3
ATSI	Build a new Toronto 345/138 kV substation	$41.8
ATSI	Build a new West Fremont Groton Hayes 138 kV line	$45.0
ATSI	Reconductor the ATSI portion of South Canton Harmon 345 kV line	$6.0
ATSI	Add a new 150 MVAR SVC and 100 MVAR capacitor at New Castle	$31.7
DLCO	Install a third 345/138 kV transformer at Collier	$8.0

Table 11-18 Major upgrade projects in Southern Region (New Table)

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

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." [23,24] Such criteria "must not be unduly discriminatory or preferential."[25]

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.[26] 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.[27]

Order No. 1000 allows, but does not require, competitive bidding to solicit transmission projects or developers.[28] The rule does not override or otherwise affect state or local laws concerning construction of transmission facilities, such as siting or permitting.[29]

On July 19, 2012, the Commission denied a complaint filed by Primary Power, LLC, finding that "PJM acted in accordance with its current Operating Agreement in selecting the alternative projects," which were sponsored by incumbents.[30] 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."[31] The MMU also pointed out that Primary Power's complaint demonstrated that the concepts of "sponsorship," "upgrades" and new versus revised projects needed clarification.[32] 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."[33]

The MMU recommends that PJM include in its Order No. 1000 compliance filing, due October 11, 2012, rules that clarify how nonincumbents can compete to provide transmission projects. This should allow nonincumbents to compete on a physical basis by having the opportunity to compete to provide transmission projects and to compete on a financial basis by having the opportunity to compete directly to finance such projects.

23 Order No. 1000, FERC Stats. & Regs. ¶31,323 (2011).
24 Order No. 1000 at PP 323–327.
25 *Id.* at PP 323–324.
26 *Id.* at PP 313–322.
27 *Id.* at P 318–319.
28 *Id.* at P 321 & n.302.
29 *Id.* at PP 337, 339.
30 140 FERC ¶ 61,054 at P 69.
31 Motion for Leave to Answer and Answer of the Independent Market Monitor for PJM, filed in Docket No. EL12-69-000 (June 22, 2012).
32 *Id.* at 3–4.
33 140 FERC ¶ 61,054 at P 83.

