Generation and Transmission Planning

Overview

Planned Generation and Retirements

- **Planned Generation.** At December 31, 2011, 90,725 MW of capacity were in generation request queues for construction through 2018, compared to an average installed capacity of 180,000 MW in 2011 including the June 1, 2011, ATSI integration. Wind projects account for approximately 37,792 MW, 41.7 percent of the capacity in the queues, and combined-cycle projects account for 34,138 MW, 37.6 percent of the capacity in the queues.

- **New Generation.** Five large plants (over 500 MW) began generating in PJM in 2011. These include York Energy Center in the PECO zone, Bear Garden Generating Station in the Dominion zone, Longview Power in the APS zone, Dresden Energy Facility in the AEP zone, and Fremont Energy Center in the ATSI zone.[1] This is the first time since 2006 that a plant rated at more than 500 MW has come online in PJM. Overall, 5,008 MW of nameplate capacity were added in PJM in 2011 (excluding the integration of the ATSI zone), the most since 2002.

- **Generation Retirements.** A total of 1,322.3 MW of generation capacity retired in 2011, and it is expected that a total of 18,886 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 7,189 MW, or 41 percent of all planned retirements. Overall, 5,191.1 MW, or 29.6 percent of all retirements, 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, although changes in environmental regulations have had an impact on coal units throughout the footprint.

Generation and Transmission Interconnection Planning Process

- Any entity (developer or applicant) that requests interconnection of a generating facility, including increases to the capacity of an existing generating unit, or 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 and time associated with interconnecting to the grid potentially create barriers to entry by creating uncertainty for potential entrants.

- The queue contains a substantial number of projects that are not likely to be built. These projects may also create barriers to entry for projects that would otherwise be completed by creating uncertainty and increasing interconnection costs.

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 typically 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; Mid-Atlantic Power Pathway (MAPP); Potomac – Appalachian Transmission Highline (PATH); and Susquehanna – Roseland. The total planned costs for all of these projects are approximately five 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

1 Fremont Energy Center entered PJM after the June 1, 2011 integration of ATSI, and is included in the 5,008 MW of nameplate capacity reported above.

2 OATT Parts IV & VI.

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.[3] The goal of transmission planning should be the incorporation of transmission investment decisions into market driven processes as much as possible.

- **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.[4,5] A key limitation is the ability to retain ROFR for upgrades to the existing transmission infrastructure.

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 the end of 2011, 90,725 MW of capacity were in generation request queues for construction through 2018, compared to an average installed capacity of approximately 180,000 MW following the ATSI integration in 2011. Although it is clear that not all generation in the queues will be built, PJM has added capacity annually since 2000 (Table 11-1).[6]

Table 11-1 Year-to-year capacity additions from PJM generation queue: Calendar years 2000 through 2011[7]

	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

In 2011, five new plants of over 500 MW came online in PJM, the first time since 2006 a plant rated at over 500 MW came online. Combined cycle plants accounted for four of the five plants to come online in PJM, while a coal steam plant was the fifth. Fremont Energy Center came online after the integration of the ATSI zone on June 1, 2011.

Table 11-2 Capacity additions of plants greater than 500 MW: Calendar year 2011

Plant Name	Zone	Unit Type	ICAP (MW)
Dresden Energy Facility	AEP	Combined Cycle	545
Longview Power	APS	Coal Steam	700
Fremont Energy Center	ATSI	Combined Cycle	685
Bear Garden Generating Station	Dominion	Combined Cycle	590
York Energy Center	PECO	Combined Cycle	565

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 eight year period beginning in 2011 and ending in 2018 increased by 14,309 MW from 76,415 MW in 2010 to 90,725 MW in 2011, or 19 percent (Table 11-3).[8] Queued capacity

3 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).

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

5 *Id.* at PP 313–322.

6 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.

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

8 See the *2010 State of the Market Report for PJM* (March 10, 2011), pp. 205-206, for the queues in 2010.

scheduled for service in 2011 decreased from 25,378 MW to 13,737 MW, or 46 percent. Queued capacity scheduled for service in 2012 increased from 13,261 MW to 13,447 MW, or 1 percent. The 90,725 MW includes generation with scheduled in-service dates in 2011 and units still active in the queue with in-service dates scheduled before 2011, listed at nameplate capacity, although these units are not yet in service.

Table 11-3 Queue comparison (MW): December 31, 2011 vs. December 31, 2010

	MW in the Queue 2010	MW in the Queue 2011	Year-to-Year Change (MW)	Year-to-Year Change
2011	25,378	13,737	(11,641)	(46%)
2012	13,261	13,447	186	1%
2013	11,244	13,051	1,808	16%
2014	13,888	17,036	3,148	23%
2015	5,960	19,251	13,291	223%
2016	1,350	9,288	7,938	588%
2017	2,140	1,720	(420)	(20%)
2018	3,194	3,194	0	0%
Total	76,415	90,725	14,309	19%

Table 11-4 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.[9]

Data presented in Table 11-5 show that through 2011, 40.6 percent of total in-service capacity from all the queues was from Queues A and B and an additional 6.9 percent was from Queues C, D and E.[10] As of December 31, 2011, 31.8 percent of the capacity in Queues A and B has been placed in service, and 9.6 percent of all queued capacity has been placed in service.

The data presented in Table 11-5 show that for successful projects there is an average time of 802 days between entering a queue and the in-service date. The data also show that for withdrawn projects, there is an average time of 483 days between entering a queue and completion or exiting. For each status, there is substantial variability around the average results.

Table 11-4 Capacity in PJM queues (MW): At December 31, 2011[11,12]

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	1,086	555	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	0	3,978	4,482
N Expired 31-Jan-05	177	2,143	173	7,913	10,407
O Expired 31-Jul-05	966	1,471	872	4,283	7,592
P Expired 31-Jan-06	502	2,625	655	4,908	8,690
Q Expired 31-Jul-06	1,109	1,454	3,408	8,643	14,614
R Expired 31-Jan-07	4,587	1,366	608	16,194	22,755
S Expired 31-Jul-07	2,337	3,198	383	11,475	17,393
T Expired 31-Jan-08	11,425	927	471	14,845	27,667
U Expired 31-Jan-09	6,005	226	621	26,506	33,357
V Expired 31-Jan-10	10,837	152	1,800	4,332	17,122
W Expired 31-Jan-11	13,659	22	1,179	9,420	24,280
X Expires 31-Jan-12	28,121	0	104	1,602	29,827
Total	79,745	31,403	10,980	204,931	327,059

Table 11-5 Average project queue times (days): At December 31, 2011

Status	Average (Days)	Standard Deviation	Minimum	Maximum
Active	844	648	0	4,420
In-Service	802	668	0	3,602
Suspended	2,448	925	704	4,103
Under Construction	1,211	826	0	4,370
Withdrawn	483	490	0	3,186

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. There has been a substantial increase in combined cycle units added to the queues. On December 31, 2011, there were 34,788 MW of capacity from combined cycle units in the queue, compared to 16,451 MW in 2010, an increase of 111.5 percent.

9 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.

10 The data for Queue X include projects through December 31, 2011.

11 The *2011 State of the Market Report for PJM* contains all projects in the queue including reratings of existing generating units and energy only resources.

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

Table 11-6 Capacity additions in active or under-construction queues by control zone (MW): At December 31, 2011

	CC	CT	Diesel	Hydro	Nuclear	Solar	Steam	Storage	Wind	Total
AECO	1,775	753	9	0	0	685	15	0	2,541	5,779
AEP	4,355	0	77	70	0	118	1,346	0	13,026	18,991
AP	930	0	8	98	0	223	597	32	1,065	2,954
ATSI	268	72	22	0	30	52	135	0	947	1,525
BGE	678	0	29	0	1,640	0	132	0	0	2,479
ComEd	1,080	483	103	23	607	95	1,366	0	14,841	18,597
DAY	0	0	2	112	0	33	12	0	1,685	1,844
DLCO	0	0	0	0	91	0	0	0	0	91
Dominion	6,171	595	12	0	1,669	90	429	52	984	10,002
DPL	1,759	56	0	0	0	337	22	34	850	3,058
JCPL	2,729	27	30	0	0	1,178	0	0	0	3,964
Met-Ed	3,510	0	21	0	39	183	0	3	0	3,756
PECO	663	7	6	0	490	21	0	2	0	1,189
PENELEC	905	20	5	0	0	56	146	0	1,565	2,697
Pepco	5,547	0	6	0	0	10	0	0	0	5,563
PPL	1,354	11	4	3	1,700	146	34	20	268	3,540
PSEG	3,065	1,083	9	0	50	361	105	2	20	4,695
Total	34,788	3,108	343	306	6,316	3,589	4,339	145	37,792	90,725

Table 11-7 Capacity additions in active or under-construction queues by LDA (MW): At December 31, 2011[13]

	CC	CT	Diesel	Hydro	Nuclear	Solar	Steam	Storage	Wind	Total
EMAAC	9,990	1,926	54	0	540	2,583	142	38	3,411	18,684
SWMAAC	6,225	0	35	0	1,640	10	132	0	0	8,042
WMAAC	5,769	31	30	3	1,739	385	180	23	1,833	9,993
Non-MAAC	12,804	1,150	224	303	2,397	611	3,885	84	32,548	54,005
Total	34,788	3,108	343	306	6,316	3,589	4,339	145	37,792	90,725

Table 11-8 Existing PJM capacity: At December 31, 2011[14] (By zone and unit type (MW))

	CC	CT	Diesel	Hydroelectric	Nuclear	Solar	Steam	Storage	Wind	Total
AECO	154	661	21	0	0	37	1,110	0	8	1,990
AEP	4,912	3,676	59	1,073	2,094	0	21,571	0	1,553	34,938
AP	1,129	1,180	36	80	0	0	8,451	27	799	11,702
ATSI	685	1,661	52	0	2,134	0	7,998	0	0	12,530
BGE	0	835	7	0	1,705	0	3,007	0	0	5,554
ComEd	1,763	7,178	86	0	10,421	0	6,790	0	1,945	28,183
DAY	0	1,369	48	0	0	1	4,368	0	0	5,785
DLCO	244	15	0	6	1,777	0	1,244	0	0	3,286
Dominion	4,025	3,761	167	3,589	3,558	0	8,283	0	0	23,383
DPL	1,125	1,773	96	0	0	0	1,825	0	0	4,819
External	974	990	0	66	439	0	6,289	0	185	8,943
JCPL	1,693	1,225	33	400	615	0	15	0	0	3,980
Met-Ed	2,041	416	42	20	805	0	844	0	0	4,167
PECO	3,209	836	7	1,642	4,541	3	1,505	1	0	11,743
PENELEC	0	344	46	513	0	0	6,834	0	630	8,366
Pepco	230	1,327	12	0	0	0	4,679	0	0	6,248
PPL	1,810	618	49	581	2,470	0	5,527	0	220	11,274
PSEG	2,960	2,863	5	5	3,493	83	2,125	0	0	11,534
Total	26,953	30,725	764	7,975	34,051	124	92,464	28	5,339	198,424

13 WMAAC consists of the Met-Ed, PENELEC, and PPL Control Zones.
14 The capacity described in this section refers to all installed capacity in PJM, regardless of whether the capacity entered the RPM auction.

Table 11-6 shows the projects under construction or active as of December 31, 2011, by unit type and control zone. Most of the steam projects (93.7 percent of the MW) and most of the wind projects (90.9 percent of the MW) are outside the Eastern MAAC (EMAAC)[15] and Southwestern MAAC (SWMAAC)[16] locational deliverability areas (LDAs).[17] Of the total capacity additions, only 18,684 MW, or 20.5 percent, are projected to be in EMAAC, while 8,042 MW or 8.9 percent are projected to be constructed in SWMAAC. Of total capacity additions, 36,719 MW, or 40.4 percent of capacity, is being added inside MAAC zones. Overall, 70.5 percent of capacity is being added outside EMAAC and SWMAAC, and 59.5 percent of capacity is being added outside MAAC zones.

Wind projects account for approximately 37,792 MW of capacity or 41.7 percent of the capacity in the queues and combined-cycle projects account for 34,788 MW of capacity or 37.6 percent of the capacity in the queues.[18] Wind projects account for 3,423 MW of capacity in MAAC LDAs, or 14.3 percent. While there are no wind projects in the SWMAAC LDA, in the EMAAC LDA wind projects account for 3,411 MW of capacity, or 18.3 percent.

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 shows that in the EMAAC LDA, gas burning unit types account for 60.3 percent of the capacity additions. Steam additions (coal) account for 0.8 percent of the MW and solar projects account for 13.8 percent of the MW in the queue for the EMAAC LDA. Nuclear and gas capacity comprise 97.8 percent of the MW capacity additions in the SWMAAC LDA. The wind and solar capacity in this section are reported at nameplate capacity and not at derated levels.

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. Elsewhere in the PJM footprint, continued reliance on steam (mainly coal) seems likely, although changes in environmental regulations and natural gas costs are expected to have an impact on coal units throughout the footprint.

Table 11-9 shows the age of PJM generators by unit type. As most steam units in PJM are from 30 to 60 years old, it appears likely that significant and disproportionate retirements of steam units will occur within the next 10 to 20 years, particularly if stricter environmental regulations make steam units more costly to operate. While steam units comprise 46.6 percent of all current MW, steam units 40 years of age and older comprise 81.1 percent of all MW 40 years of age and older and 87.2 percent of such MW if hydroelectric is excluded from the total. Approximately 7,930 MW of steam units 40 years of age and older are located in EMAAC and SWMAAC, or 15.7 percent of all steam units 40 years and older.

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. In 2018, CC and CT generators would account for 57.9 percent of EMAAC generation, an increase of 9.4 percentage points from 2011 levels. Accounting for the fact that about 925 MW of steam units over 40 years old are gas-fired, the result would be an increase in the proportion of gas-fired capacity in EMAAC from 51.2 percent to 57.9 percent. The proportion of gas-fired capacity in EMAAC would increase to 62.0 percent if the derating to 13 percent of nameplate for wind capacity is reflected, meaning that the effective capacity additions are 15,716 MW.

15 EMAAC consists of the AECO, DPL, JCPL, PECO and PSEG Control Zones.
16 SWMAAC consists of the BGE and Pepco Control Zones.
17 See the *2011 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography" for a map of PJM LDAs.
18 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 38,301 MW of wind resources and 3,589 MW of solar resources, the 90,725 MW currently active in the queue would be reduced to 55,620 MW.

Table 11-9 PJM capacity (MW) by age: at December 31, 2011

Age (years)	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Solar	Steam	Storage	Wind	Total
Less than 11	19,000	8,814	400	11	0	124	1,864	28	5,305	35,547
11 to 20	5,927	12,557	113	48	0	0	3,390	0	34	22,069
21 to 30	1,584	1,700	55	3,448	15,359	0	7,870	0	0	30,017
31 to 40	244	2,935	43	105	16,344	0	28,862	0	0	48,533
41 to 50	198	4,719	138	2,915	2,349	0	30,418	0	0	40,737
51 to 60	0	0	15	379	0	0	16,971	0	0	17,365
61 to 70	0	0	0	0	0	0	2,939	0	0	2,939
71 to 80	0	0	0	284	0	0	95	0	0	379
81 to 90	0	0	0	549	0	0	54	0	0	603
91 to 100	0	0	0	151	0	0	0	0	0	151
101 and over	0	0	0	84	0	0	0	0	0	84
Total	26,953	30,725	764	7,975	34,051	124	92,464	28	5,339	198,424

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	2.2%	9,141	26.8%	9,990	18,933	42.5%
	Combustion Turbine	2,484	28.0%	7,358	21.6%	1,926	6,801	15.3%
	Diesel	53	0.6%	162	0.5%	54	162	0.4%
	Hydroelectric	2,042	23.0%	2,047	6.0%	0	620	1.4%
	Nuclear	615	6.9%	8,648	25.4%	540	8,574	19.3%
	Solar	0	0.0%	123	0.4%	2,583	2,706	6.1%
	Steam	3,472	39.2%	6,580	19.3%	142	3,250	7.3%
	Storage	0	0.0%	1	0.0%	38	39	0.1%
	Wind	0	0.0%	8	0.0%	3,411	3,419	7.7%
	EMAAC Total	8,863	100.0%	34,067	100.0%	18,684	44,503	100.0%
SWMAAC	Combined Cycle	0	0.0%	230	1.9%	6,225	6,455	44.2%
	Combustion Turbine	777	14.8%	2,162	18.3%	0	1,384	9.5%
	Diesel	0	0.0%	19	0.2%	35	54	0.4%
	Nuclear	0	0.0%	1,705	14.4%	1,640	3,345	22.9%
	Solar	0	0.0%	0	0.0%	10	10	0.1%
	Steam	4,459	85.2%	7,686	65.1%	132	3,359	23.0%
	SWMAAC Total	5,236	100.0%	11,801	100.0%	8,042	14,607	100.0%
WMAAC	Combined Cycle	0	0.0%	3,851	16.2%	5,769	9,620	60.7%
	Combustion Turbine	559	6.1%	1,377	5.8%	31	850	5.4%
	Diesel	46	0.5%	136	0.6%	30	120	0.8%
	Hydroelectric	887	9.6%	1,113	4.7%	3	1,116	7.0%
	Nuclear	0	0.0%	3,275	13.8%	1,739	5,014	31.7%
	Solar	0	0.0%	0	0.0%	385	385	2.4%
	Steam	7,737	83.8%	13,205	55.5%	180	5,648	35.7%
	Storage	0	0.0%	0	0.0%	23	23	0.1%
	Wind	0	0.0%	850	3.6%	1,833	2,683	16.9%
	WMAAC Total	9,228	100.0%	23,807	100.0%	9,993	15,838	100.0%
Non-MAAC	Combined Cycle	0	0.0%	13,731	10.7%	12,804	26,535	18.3%
	Combustion Turbine	900	2.3%	19,829	15.4%	1,150	20,079	13.8%
	Diesel	53	0.1%	447	0.3%	224	619	0.4%
	Hydroelectric	1,434	3.7%	4,814	3.7%	303	5,118	3.5%
	Nuclear	1,734	4.5%	20,423	15.9%	2,397	21,086	14.5%
	Solar	0	0.0%	1	0.0%	611	612	0.4%
	Steam	34,811	89.4%	64,994	50.5%	3,885	34,068	23.5%
	Storage	0	0.0%	27	0.0%	84	111	0.1%
	Wind	0	0.0%	4,482	3.5%	32,548	37,030	25.5%
	Non-MAAC Total	38,931	100.0%	128,749	100.0%	54,005	145,257	100.0%
All Areas	Total	62,258		198,424		90,725	220,206	

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.

Without the planned coal-fired capability in EMAAC, new gas-fired capability would represent 64.3 percent of all new capability in EMAAC and 76.5 percent when the derating of wind capacity is reflected.

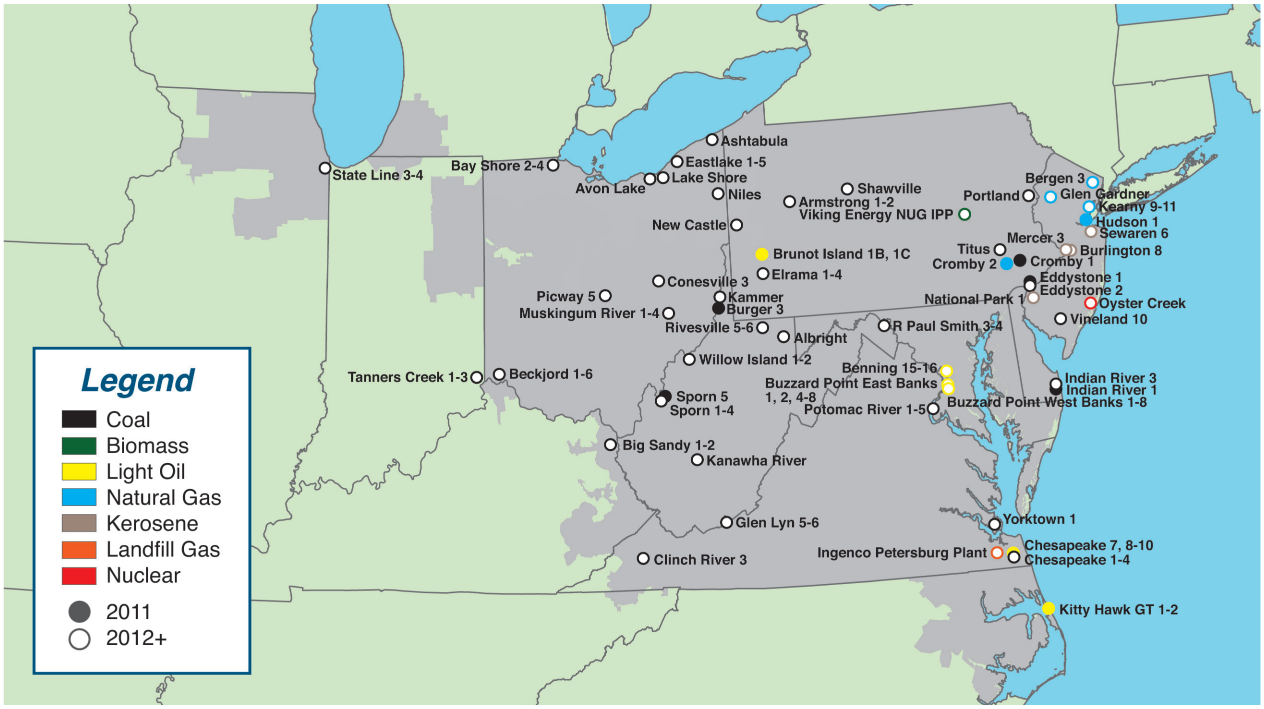
There is a planned addition of 1,640 MW of nuclear capacity in SWMAAC. Without the planned nuclear capability in SWMAAC, new gas-fired capability would represent 97.2 percent of all new capability in the SWMAAC. In 2018, this would mean that CC and CT generators would comprise 53.7 percent of total capability 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.[20] In these zones, 89.4 percent of all generation 40 years or older is steam (primarily coal). With the retirement of these units in 2018, wind farms would comprise 25.7 percent of total capacity in Non-MAAC zones, if all queued capacity is built.

Planned Deactivations

As shown in Table 11-12, 17,563.7 MW are planning to deactivate by the end of calendar year 2019. Units planning to retire in 2012 make up 7,189 MW, or 41 percent of all planned retirements. Of planned deactivations in 2012, approximately 2,185 MW, or 30.4 percent are located in the ATSI zone. Overall, 5,191.1 MW, or 29.6 percent of all retirements, are expected in the AEP zone. More retirements due to aging units lacking emission control technology are expected, particularly to comply with environmental regulations that will be in effect by 2015. Figure 11-1 shows plant retirements throughout the PJM footprint, with notable retirements in nearly every PJM state. Table 11-12 and Figure 11-1 do not include the planned retirements of Fisk 19 and Crawford 7&8, due to uncertain deactivation dates. Fisk 19, a 328 MW unit in the ComEd zone, will retire by December 31, 2012. Crawford 7&8 (532 MW total) will retire by December 31, 2014, but could retire as early as 2012.[21] A total of 1,322.3 MW retired in 2011, and it is expected that a total of 18,886 MW will have retired by 2019, with most of this capacity retiring by the end of 2015.

Figure 11-1 Unit retirements in PJM Calendar year 2011 through 2019



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

21 See "Edison International Reports 2011 Results" <http://www.edison.com/pressroom/pr.asp?bu=&year=0&id=7865> Accessed March 1, 2012

Table 11-11 Summary of PJM unit retirements (MW): Calendar year 2011 through 2019[22]

	MW
Retirements 2011	1,322.3
Planned Retirements 2012	7,189.0
Planned Retirements Post-2012	10,374.7
Total	18,886.0

Table 11-12 Planned deactivations of PJM units in Calendar year 2012 as of March 1, 2012[23,24,25]

Unit	Zone	MW	Projected Deactivation Date
Sporn 5	AEP	440.0	31-Dec-11
State Line 3-4	ComEd	515.0	01-Apr-12
Viking Energy NUG IPP	PPL	16.0	01-Mar-12
Beckjord 1-3	DEOK	316.0	01-May-12
Benning 15-16	Pepco	548.0	31-May-12
Buzzard Point East Banks 1, 2, 4-8	Pepco	112.0	31-May-12
Buzzard Point West Banks 1-8	Pepco	128.0	31-May-12
Eddystone 2	PECO	309.0	31-May-12
Niles	ATSI	217.0	01-Jun-12
Elrama 1-4	DLCO	460.0	01-Jun-12
Kearny 10-11	PSEG	250.0	01-Jun-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
Ashtabula	ATSI	210.0	01-Sep-12
Bay Shore 2-4	ATSI	419.0	01-Sep-12
Eastlake 1-5	ATSI	1,149.0	01-Sep-12
Lake Shore	ATSI	190.0	01-Sep-12
Potomac River 1-5	Pepco	482.0	01-Oct-12
Total		6,863.0	

Table 11-13 Planned deactivations of PJM units after calendar year 2012, as of March 1, 2012[26]

Unit	Zone	MW	Projected Deactivation Date
Ingenco Petersburg Plant	Dominion	2.9	31-May-13
Indian River 3	DPL	169.7	31-Dec-13
Big Sandy 1-2	AEP	1,078.0	31-Dec-14
Clinch River 3	AEP	230.0	31-Dec-14
Conesville 3	AEP	165.0	31-Dec-14
Glen Lyn 5-6	AEP	325.0	31-Dec-14
Kammer	AEP	600.0	31-Dec-14
Kanawha River	AEP	400.0	31-Dec-14
Muskingum River 1-4	AEP	790.0	31-Dec-14
Picway 5	AEP	95.0	31-Dec-14
Sporn	AEP	580.0	31-Dec-14
Tanners Creek 1-3	AEP	488.1	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	01-Jan-15
Beckjord 4-6	DEOK	802.0	01-Apr-15
Avon Lake	ATSI	732.0	01-Apr-15
New Castle	ATSI	330.5	01-Apr-15
Titus	Met-Ed	243.0	01-Apr-15
Shawville	PENELEC	597.0	01-Apr-15
Glen Gardner	JCPL	160.0	01-May-15
Kearny 9	PSEG	21.0	01-May-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 6	PSEG	105.0	01-Jun-15
Chesapeake 3-4	Dominion	354.0	31-Dec-15
Oyster Creek	JCPL	614.5	31-Dec-19
Total		9,842.7	

As shown in Table 11-14, 6,663.5 MW of capacity is at risk for retirement due to its status as a High Electric Demand Day unit in the state of New Jersey. Of these HEDD units, 4,271.5 MW or 64 percent, are in the PSEG zone. While some of these units may retire due to lacking the emission controls needed, others will likely be retro-fitted to comply with New Jersey environmental regulations. Of these, 714 MW have already submitted a retirement notice to PJM.

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

23 See "Pending Deactivation Requests" <http://pjm.com/planning/generation-retirements/~/media/planning/gen-retire/pending-deactivation-requests.ashx> (Accessed March 1, 2012).

24 Sporn 5 retired February 13, 2012, following a decision by the Ohio PUC.

25 See "GenOn Reports 2011 Results and Announces Expected Deactivation of Generation Units"<http://phx.corporate-ir.net/phoenix.zhtml?c=124294&p=irol-newsArticle&ID=1667152&highlight=> (Accessed March 1, 2012)

26 See "AEP Shares Plan For Compliance With EPA Regulations" <http://www.aep.com/newsroom/newsreleases/?id=1697> (Accessed March 1, 2012)

Table 11-14 HEDD Units in PJM as of December 31, 2011[27]

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 2011

Table 11-15 shows unit deactivations for 2011.[28] A total of 1,322.3 MW retired in 2011, including 94.0 MW from FirstEnergy Corp., 90.0 MW from NRG Energy Inc., 101.3 MW from Dominion Resources, Inc., 30.0 MW from GenOn Energy, Inc., 624.0 MW from Exelon Corporation, and 383.0 MW from Public Service Enterprise Group Incorporated. The retirements were 607.0 MW of coal, 131.3 MW of light oil, and 584.0 MW of natural gas generation. Of these retirements, 624.0 MW were in the PECO zone, 30.0 MW in the DLCO zone, 101.3 MW in the Dominion zone, 90.0 MW in the DPL zone, 94.0 MW in the ATSI zone, and 383.0 MW in the PSEG zone.

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

28 "*PJM Generator Deactivations*," PJM.com <http://pjm.com/planning/generation-retirements/gr-summaries.aspx> (January 1, 2012).

Generation and Transmission Interconnection Planning Process

Any entity (developer or applicant) that requests interconnection of a generating facility, including increases to the capacity of an existing generating unit, or requests interconnection of a merchant transmission facility, must follow the process defined in the PJM tariff to obtain interconnection service.[29] The process is complex and time consuming as a result of the nature of the required analyses. The cost and time associated with interconnecting to the grid potentially create barriers to entry by creating uncertainty for potential entrants.

The queue contains a substantial number of projects that are not likely to be built. These projects may also create barriers to entry for projects that would otherwise be completed by creating uncertainty and increasing interconnection costs. The rules should create the possibility for units that are ready to begin construction to move ahead of units that are not ready and are not making real progress toward being ready to begin construction. The rules should also address the efficient disposition of capacity injection rights associated with retired or mothballed units to ensure that they are not used to block units in the queue from proceeding.

On February 29, 2012, PJM filed interconnection queue process reforms with the Commission that PJM explained "are intended to relieve bottlenecks in the interconnection queue and provide for greater certainty and transparency."[30] The specific proposals include: (i) six-month queue cycles, (ii) "sliding" queues for projects that seek to modify the size of their request by more than a specified amount; (iii) an "alternate queue" for projects less than or equal to 20 MW determined not to have an impact on the PJM grid; (iv) clarified timeframes for notifying PJM if a project is using Capacity Interconnection Rights transferred from a deactivating generator; (v) reduced suspension rights when there is a negative impact on a subsequent project; (vi) modified deposits for certain small projects; and (vii) clarified provisions on the data required for System Impact Studies. The MMU generally supports these proposals in substance and as an indicator of PJM's efforts to address interconnection issues.[31]

29 OATT Parts IV & VI.

30 PJM Filing in Docket No. ER12-1177-000.

31 *Id.*

Table 11-15 Unit deactivations: Calendar year 2011

Company	Unit Name	ICAP	Primary Fuel	Zone Name	Age (Years)	Retirement Date
Dominion Resources, Inc.	Kitty Hawk GT1	18.0	Light Oil	Dominion	39	Mar 15, 2011
Dominion Resources, Inc.	Kitty Hawk GT2	16.0	Light Oil	Dominion	39	Mar 15, 2011
Dominion Resources, Inc.	Chesapeake 8	17.5	Light Oil	Dominion	41	Mar 15, 2011
Dominion Resources, Inc.	Chesapeake 9	16.9	Light Oil	Dominion	41	Mar 15, 2011
Dominion Resources, Inc.	Chesapeake 10	16.9	Light Oil	Dominion	41	Mar 15, 2011
Dominion Resources, Inc.	Chesapeake 7	16.0	Light Oil	Dominion	40	Apr 08, 2011
NRG Energy Inc.	Indian River 1	90.0	Coal	DPL	50	May 01, 2011
Exelon Corporation	Cromby 1	144.0	Coal	PECO	55	May 31, 2011
Exelon Corporation	Eddystone 1	279.0	Coal	PECO	49	May 31, 2011
GenOn Energy, Inc.	Brunot Island 1B	15.0	Light Oil	DLCO	39	Jun 01, 2011
GenOn Energy, Inc.	Brunot Island 1C	15.0	Light Oil	DLCO	39	Jun 01, 2011
FirstEnergy Corp.	Burger 3	94.0	Coal	ATSI	61	Sep 01, 2011
Public Service Enterprise Group Incorporated	Hudson 1	383.0	Natural Gas	PSEG	39	Dec 08, 2011
Exelon Corporation	Cromby 2	201.0	Natural Gas	PECO	54	Dec 31, 2011

Table 11-16 Generation and transmission interconnection timeline

Process Step	Start on	Complete by	Days to complete	Days to decide whether to continue
Feasibility Study	January 31	April 30	90	30
	April 30	July 31		
	October 31	October 31		
	January 31	January 31		
System Impact Study	January 31	June 01	120	30
	April 30	September 01		
	July 31	December 01		
	October 31	March 01		
Facilities Study	Upon acceptance of the Facilities Study Agreement	Varies	Varies	60
Interconnection Service Agreement	Upon acceptance of an Interconnection Service Agreement	Varies	Varies	60
Interconnection Construction Service Agreement	Upon acceptance of Interconnection Construction Service Agreement	Varies	Varies	NA

Table 11-17 Impact Study Agreement deposit requirements

Project Size	Non-Refundable Deposit	Non-Refundable Cost per MW	Refundable Cost per MW	Maximum Deposit
<= 2MW	$5,000	$0	$0	NA
> 2 MW, <= 20 MW	$10,000	$0	$0	NA
> 20 MW, <= 100 MW	$0	$500	$0	NA
> 100 MW	$50,000	$0	$300	$300,000

Participation in the PJM Capacity Market requires procurement of capacity interconnection rights. These rights persist during the unit's lifetime, and expire one year after a unit is retired.[32] The rights persist if, during that additional year, the unit owner submits a new interconnection request at the same point of interconnection.[33]

Any entity (developer or applicant) that requests interconnection of a generating facility, including increases to the capacity of an existing generating unit, or requests interconnection of a merchant transmission facility, must follow the PJM interconnection process.[34] With the assumption that a facilities study is not required, and accounting for the time required by PJM to complete the required studies, it takes approximately ten months from the initial request for interconnection to the point where the applicant can begin to negotiate an Interconnection Service Agreement. Upon execution of the Interconnection Service Agreement, the parties can then develop an Interconnection Construction Service Agreement, which is used to develop an agreed upon schedule of work for construction (Table 11-16).

Initiating the Planning Process

To initiate the interconnection planning process, an applicant must submit a Feasibility Study Agreement to PJM for execution along with required information about the project and the appropriate fees.[35] The applicant is obligated to pay the actual costs of studies conducted on its behalf. The feasibility study fees depend on when the request is submitted and the size of the interconnection request but the initial deposit cannot exceed $100,000. Resources that are 20 MW or less, or qualify as small resources, can often use an expedited queue process, under which a small resource can receive interim Capacity Interconnection Rights if a queue project is ready to be put in service ahead of other queued projects.

Feasibility Study

A developer is required to elect capacity resource status or energy only resource status. Capacity resource status allows the generator to meet capacity obligations through RPM, while energy resource status allows the unit to participate in the energy market only. In order to qualify as a capacity resource, sufficient transmission capability must exist to ensure the deliverability of the generator output to network load and to satisfy the reliability requirements of the NERC region in which the generator is located.[36]

Feasibility studies are performed four times each year. The feasibility studies are performed by PJM and the affected Transmission Owners (TO), who provide verification of PJM results. The TOs also provide preliminary cost estimates for the project. The feasibility study is limited to short-circuit studies and load-flow analysis of probable contingencies, and does not include a stability analysis. In general, the feasibility study will be completed within 90 days.

System Impact Study

If the developer decides to proceed with the System Impact Study, they must pay the transmission provider a deposit (Table 11-17).[37]

The System Impact Study is a comprehensive regional analysis of the impact of adding the new generation or transmission facility to the system including the impact on deliverability to PJM load in the region where the generator or transmission facility is located. The System Impact Study identifies the system constraints relating to the new project and the necessary attachment facilities, local upgrades and network upgrades required to maintain reliability and deliverability in the region. The System Impact Studies are performed by PJM staff, in coordination with the affected TOs, who provide verification of PJM results. The TOs also provide more comprehensive cost estimates for the project than provided with the feasibility studies. System Impact Studies are performed four times each year.

The System Impact Study considers relationships among the new generator or transmission facility,

32 OATT § 230.3.3.

33 *Id.*

34 The material in this section is based on PJM Manual M-14A: Generation and Transmission Interconnection Process. "M-14A: Generation and Transmission Interconnection Process", Revision 9 (April 12, 2011).

35 The Feasibility Study Agreements are identified as Attachment N of the PJM Open Access Transmission Tariff (OATT) for generation interconnection requests and Attachment S of the PJM OATT for merchant transmission interconnection requests.

36 The PJM footprint includes all or part of Reliability*First* and the SERC Reliability Corporation (SERC) NERC regions.

37 See OATT § 204.3A.

other planned generators in the queue, and the existing system. The System Impact Study includes projects that were in the queue ahead of the project being studied. The Study attempts to model each project in the queue to appropriately identify the dependencies among the projects.

Facilities Study

If the applicant decides to proceed with a Facilities Study, the applicant must submit a required refundable deposit in the amount of $100,000 or the estimated amount of its Facilities Study cost responsibility for the first three months of work on the study, whichever is greater. If the applicant requests a Facilities Study, the results of the System Impact Study are incorporated in the Regional Transmission Expansion Plan (RTEP) Process.

The Facilities Study provides an estimate of the cost to the applicant for attachment facilities, local upgrades and network upgrades necessary to accommodate the project, and an estimate of the time required to complete the design and construction of the facilities and upgrades. The Facilities Studies are performed by the affected TOs. The TOs also provide more accurate cost estimates for the project than provided with feasibility studies and system impact studies. The time to complete a Facilities Study varies depending on the elements under study.

Interconnection Service Agreement

If the applicant decides to proceed with an Interconnection Service Agreement, they must provide PJM with a letter of credit or other acceptable form of security in the amount equal to the estimated costs of new facilities or upgrades for which the applicant is responsible. The applicant must also demonstrate: completion of a fuel deliverability agreement and water agreement (if necessary); control of any necessary rights-of-way for fuel and water interconnections (if necessary); acquisition of any necessary local, county and state site permits; and a signed memorandum of understanding for the acquisition of major equipment. PJM may also request milestone dates for permitting, regulatory certifications, or third party financial arrangements.

Interconnection Construction Service Agreement

Once an Interconnection Service Agreement is executed, PJM is required to tender an Interconnection Construction Service Agreement among the applicant, PJM and the affected Interconnection Transmission Owner(s) within 45 days. The applicant then has 60 days to execute the Interconnection Construction Service Agreement. If the Transmission Owner and the applicant cannot agree upon the terms of the Interconnection Construction Service Agreement, dispute resolution may be requested, and the customer has the option to design and install all or any portion of the Transmission Owner Interconnection Facilities under the "Option to Build" clause.[38]

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 typically 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; Mid-Atlantic Power Pathway (MAPP); Potomac – Appalachian Transmission Highline (PATH); and Susquehanna – Roseland. The total planned costs for all of these projects are approximately five billion dollars.[39]

On August 18, 2011, the PJM Board of Managers instructed Pepco Holdings, Inc. (PHI) to delay the construction of the MAPP transmission line. The PJM RTEP analysis, using the most current economic forecasts, demand response commitments and potential new generation, showed that the MAPP project can be delayed. As a result, the initial MAPP in-service date of 2015 has been moved to 2019-2021. The PJM Board of Managers advised PHI to sustain efforts needed to allow the MAPP project to be resumed when it is needed.[40]

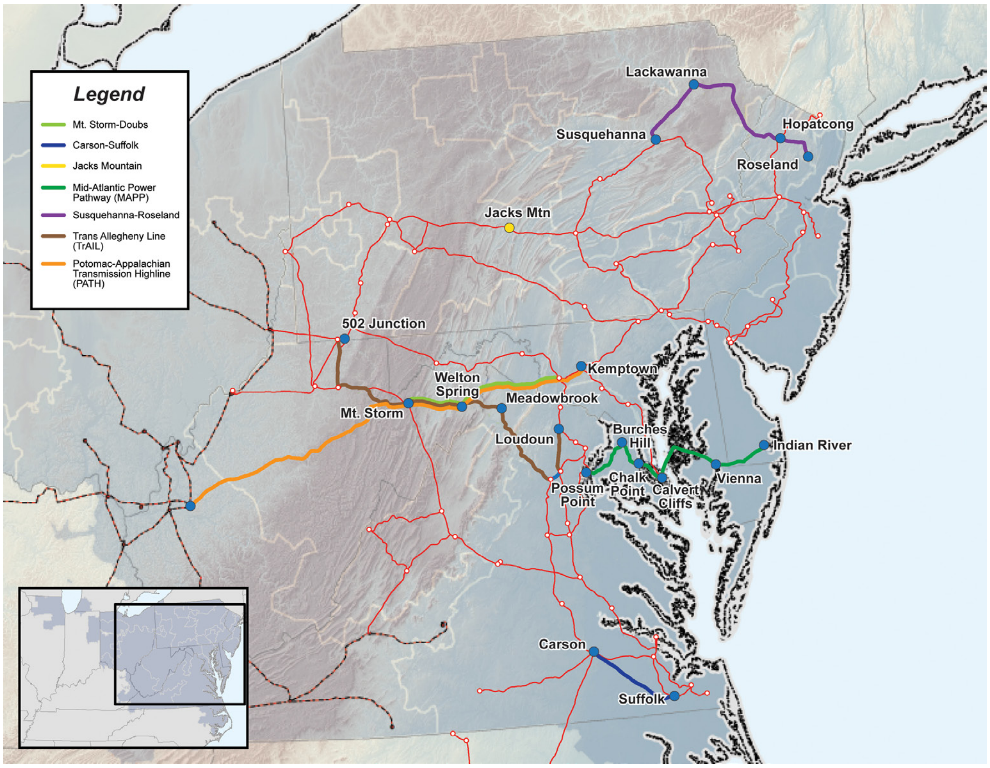
38 See PJM. "PJM Open Access Transmission Tariff", Sixth Revised Sheet No. 224CC (Effective March 1, 2007) Section VI.212.6.

39 Total estimated cost calculated from the backbone project cost estimates found in the "Construction Status Database" located at <http://www.pjm.com/planning/rtep-upgrades-status/backbone-status.aspx>.

40 See "PJM Board directs delay in MAPP Transmission Line,", <http://www.pjm.com/about-pjm/newsroom/newsletter-notices/state-lines/2011/september.aspx#Article_4> (Accessed October 22, 2011).

In early October 2011, the Interagency Rapid Response Team for Transmission named the Susquehanna-Roseland power line project to the initial list of seven transmission line projects for rapid review and permit process. The Rapid Response Team is a federal interagency team consisting of the Department of Agriculture, the Department of Commerce, the Department of Defense, the Department of Energy, the Department of the Interior, the Environmental Protection Agency, the Federal Electric Regulatory Commission, the Advisory Council on Historic Preservation and the White House Council on Environmental Quality.[41] The Rapid Response Team for Transmission was implemented to coordinate, improve and accelerate the permitting process for critical transmission line projects in order to improve overall reliability of the US power grid.[42]

Figure 11-2 Map of Backbone Projects[43]



Mount Storm – Doubs

The Mount Storm – Doubs transmission line includes 65.7 miles in West Virginia, 30.7 miles in Virginia and 2.8 miles in Maryland. Under this project, the existing transmission towers will be replaced, resulting in an increase in capacity of about 60 percent. The construction will occur within the existing right-of-way. The required in-service date for this project is June 2020. The project is currently estimated to cost between $320 and $370 million.[44,45]

Jacks Mountain

The Jacks Mountain project includes a new 500 kV substation at Jacks Mountain and 1,000 MVARs of capacitors. The project requires the replacement of a wave trap (a device used to divert communication signals sent on the transmission line from the remote substation to the telecommunications/protection panel in the substation control room) and an upgrade of a section at the Keystone 500 kV bus, the replacement of two wave traps at the Juniata 500 kV bus as well as relay changes at the Juniata 500 kV substation. This project has been deemed necessary to resolve voltage problems for load deliverability reliability criteria violations starting on June 1, 2013, and is required to be in service by that date.

Currently, all land required for this project has been procured. The transmission line engineering design is in process, and the detailed substation engineering design is expected to be completed in the summer of 2013. The procurement of transmission line hardware and substation equipment has been scheduled for the middle of 2013, for delivery in 2014. The 500 kV breakers have been ordered, and are scheduled for delivery in October

41 See "Interagency Rapid Response Team for Transmission," <http://www.whitehouse.gov/administration/eop/ceq/initiatives/interagency-rapid-response-team-for-transmission> (Accessed October 28, 2011).

42 See "Energy Projects Energy Infrastructure Update for September 2011," <http://www.ferc.gov/legal/staff-reports/10-21-11-energy-infrastructure.pdf> (Accessed January 30, 2012).

43 Source: PJM © 2011. All rights reserved.

44 See PJM.com. "Mount Storm – Doubs," <http://www.pjm.com/planning/rtep-upgrades-status/backbone-status/mount-storm-doubs.aspx> (Accessed January 1, 2012)

45 See Dominion. "Mt. Storm – Doubs 500kV Rebuild Project,"<http://www.dom.com/about/electric-transmission/mtstorm/index.jsp> (Accessed January 1 ,2012)

2014 and January 2015. The necessary 500 kV capacitor banks are also on order, with a scheduled delivery of January 2015. The 500 kV disconnect switches are on order, with a scheduled delivery of October 2014.[46]

Mid-Atlantic Power Pathway (MAPP)

The MAPP transmission project will serve the District of Columbia, Maryland and Delaware. This project will consist of approximately 69 miles of alternating current lines and 83 miles of direct current lines. The majority of this line will be built on, or adjacent to, existing transmission lines. The project requires a new 500 kV transmission line from the Possum Point to the Calvert Cliffs substations, and two 500 kV High Voltage Direct Current (HVDC) circuits from a new substation in Calvert Cliffs, MD, to a new substation in Wicomico County, MD and to a new substation in Sussex County, DE. Included in these circuits is a submarine cable crossing of the Chesapeake Bay.

Potomac – Appalachian Transmission Highline (PATH)

The Potomac - Appalachian Transmission Highline (PATH) project is required to resolve reliability criteria violations. The PATH project consists of a 765 kV transmission line extending approximately 275 miles from the Amos Substation, which is located in southwestern West Virginia, to the proposed Kemptown (765/500 kV) Substation, located in central Virginia. The project also includes a new Welton Spring (765/500 kV) Substation.

Currently, right-of-way issues are being discussed in West Virginia, Virginia and Maryland. The property for the Welton Spring and Kemptown substations has been acquired. The preliminary engineering design work, as well as the preliminary procurement activities, is in progress. Construction will be scheduled to begin following receipt of state commission approvals to construct. The required in-service date for the PATH line is June 1, 2015.[47]

PJM is in the process of considering new information, including fuel cost estimates, emissions costs, future generation scenarios, load forecast updates and demand response projections.

Susquehanna – Roseland (S-R)

The Susquehanna - Roseland project is a new 500 kV transmission line from Susquehanna, located in central eastern Pennsylvania, to Roseland, located in north central New Jersey, which is required to resolve reliability criteria violations starting on June 1, 2012. The project will require an upgrade of seven 230 kV and one 500 kV substations, as well as three new 500 kV substations, two with a 500/230 kV transformers.

Currently, construction and right-of-way permit applications have been submitted with the National Park Service (NPS). A decision on the applications is not expected from the NPS until October of 2012. Additionally, the issuance of a New Jersey Department of Environmental Protection (NJDEP) Wetland and Flood Hazard Area Permit has also been delayed. While PJM has required an in-service date of June 1, 2012, construction of the project has been delayed as a result. The expected in-service date for the Roseland to Hopatcong portion is June 2014, with the remainder of the project to be completed by June 2015.[48]

In early October 2011, the Interagency Rapid Response Team for Transmission named the Susquehanna–Roseland power line project to the initial list of seven transmission line projects for rapid review and permit process.

Trans Allegheny Line (TrAIL)

The Trans Allegheny Line (TrAIL) project is necessary to meet growing demand in the Mid-Atlantic region and is required to resolve reliability criteria violations starting June 1, 2011. The project includes a new 500 kV transmission line extending from 502 Junction to Loudoun substation, and includes: a 76.8 mile segment from the 502 Junction bus to the Mt. Storm bus; a 60.1 mile segment from the Mt. Storm bus to the Meadowbrook bus; and an 80.8 mile segment from the Meadowbrook bus to the Loudoun bus.

The TrAIL project was completed on May 19, 2011.[49]

46 See PJM.com. "Jacks Mountain," <http://www.pjm.com/planning/rtep-upgrades-status/backbone-status/jacks-mountain.aspx> (Accessed January 30, 2012).

47 See PJM.com. "Potomac – Appalachian Transmission Highline (PATH) <http://www.pjm.com/planning/rtep-upgrades-status/backbone-status/path.aspx>. (Accessed January 1, 2012)

48 See PJM.com. "Susquehanna – Roseland," <http://www.pjm.com/planning/rtep-upgrades-status/backbone-status/susquehanna-roseland.aspx>. (Accessed January 30, 2012).

49 See TrAIL. (2012) <http://www.aptrailinfo.com/index.php>. (2012)

Economic Planning Process

Transmission system investments can be evaluated on a reliability basis or on an economic basis. The reliability evaluation examines whether a transmission upgrade is required in order to maintain reliability on the system in a particular area or areas, using specific planning and reliability criteria.[50] The economic evaluation examines whether a transmission upgrade, including reliability upgrades, results in positive economic benefits. The economic evaluation is more complex than a reliability evaluation because there is more judgment involved in the choice of relevant metrics for both benefits and costs.

As an RTO, PJM is responsible to constantly evaluate the need for transmission investments related to reliability and to help ensure the construction of needed facilities. As the operator and designer of markets, PJM also needs to engage in the economic evaluation of transmission system investments. PJM has made some significant progress in this area.

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. While the RPM construct does provide that qualifying transmission upgrades may be submitted as offers, there have been no such offers. More generally, network transmission is not built based directly on market signals because the owners of network transmission are compensated through a non-market mechanism, typically under traditional regulation.

Economic Valuation Metrics

Although the PJM Tariff does not yet comprehensively address the issue of competition between transmission and generation projects to solve congestion problems, PJM has taken a first step towards integrating transmission investments into the market through the use of economic evaluation metrics.[51] Economic evaluation metrics can be used to determine whether there are positive economic benefits associated with an investment in transmission that might warrant the investment even when it is not required for reliability. The goal of transmission planning should be the incorporation of transmission investment decisions into market driven processes as much as possible.

PJM performs a market efficiency analysis to compare the costs and benefits of (i) accelerating reliability-based enhancements or expansions already included in the regional transmission plan that, if accelerated, also could relieve one or more economic constraints; (ii) modifying reliability-based enhancements or expansions already included in the regional transmission plan that, as modified, would relieve one or more economic constraints; (iii) new enhancements or expansions that could relieve one or more economic constraints, but for which no reliability-based need has been identified.[52] These economic constraints include, but are not limited to, constraints that cause significant historical gross congestion, significant historical unhedgeable congestion, pro-ration of Stage 1B ARR requests or significant congestion as forecasted in the market efficiency analysis. The market efficiency analysis uses the Benefit/Cost Ratio, defined as the present value of the total annual project benefit for each of the first 15 years divided by the present value of the project cost for the first 15 years of the project. To be included in the RTEP, the benefit/cost ratio must be greater than or equal to 1.25.

In the event that the annual review shows changes in the costs and benefits of particular projects, PJM reviews the changes with the TEAC and recommends to the PJM Board whether the project continues to provide measurable benefits and should remain in the RTEP. This yearly evaluation includes changes in cost estimates of the economic-based enhancement or expansion and changes in system conditions such as load forecasts,

50 See PJM OA Schedule 6.

51 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).

52 The process is defined in Section 1.5.7 of the PJM Tariff. See PJM. "PJM Open Access Transmission Tariff" (September 17, 2010) (Accessed January 28, 2012) <http://www.pjm.com/documents/~/media/documents/agreements/tariff.ashx>. Each year, the assumptions to be used in performing the market efficiency analysis are presented to the PJM Transmission Expansion Advisory Committee (TEAC) for review and comment and the PJM Board approves the assumptions in June of each year.

anticipated merchant transmission facilities, generation and demand response.

This annual review process has the potential to create substantial uncertainty for those building transmission facilities and for all market participants affected by the changes to the transmission system that would result from the completion of these facilities. Significant transmission projects, like the backbone facilities, have substantial impacts on energy and capacity markets and thus on the economics of both generation and load. The locational supply and demand of energy are affected and thus locational energy prices are affected. Changes in expected energy prices determine expected revenues from the energy market and expected payments to the energy market. The locational supply and demand of capacity are affected and thus locational capacity prices are affected. Changes in expected capacity prices determine expected revenues from the capacity market and expected payments to the capacity market. The uncertainty about transmission projects affects decisions about whether to invest in new generation and whether to continue to invest in existing generation. The uncertainty about transmission projects affects decisions about where to locate new load and decisions about whether to invest in demand side resources.

The MMU recommends that PJM propose modifications to the transmission planning process that would limit significant changes in the status of major transmission projects after they have been approved, and thus limit the uncertainty imposed on markets by the use of evaluation criteria that are very sensitive to changes in forecasts of economic variables.

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."[53,54] Such criteria "must not be unduly discriminatory or preferential."[55]

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.[56] 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.[57] Order No. 1000 allows, but does not require, competitive bidding to solicit transmission projects or developers.[58] The rule does not override or otherwise affect state or local laws concerning construction of transmission facilities, such as siting or permitting.[59]

53 *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, FERC Stats. & Regs. ¶31,323 (2011); *see also Primary Power, LLC*, 131 FERC ¶61,015 (2010) (reh'g pending); *Central Transmission, LLC v. PJM Interconnection L.L.C.*, 131 FERC ¶61,243 (2010).
54 Order No. 1000 at PP 323–327.
55 *Id.* at PP 323–324.
56 *Id.* at PP 313–322.
57 *Id.* at P 318–319.
58 *Id.* at P 321 & n.302.
59 *Id.* at PP 337, 339.